Overland
Consulting

Audit of Relationships and Transactions Between Public Service Electric and Gas Company and its Affiliates and a Comprehensive Management Audit of Public Service Electric and Gas Company

Submitted to:

New Jersey Board of Public Utilities

Submitted by:

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Introduction

The Overland audit was generally supported by both PSEG and PSE&G personnel. The company provided dedicated personnel to support our discovery and audit task requirements. We appreciate the cooperation provided to us in the conduct of our review, which allowed the development of thorough consideration of most areas of corporate operations included in this report.

This report is organized in a manner that is generally consistent with the structure of the scope of effort requested by the New Jersey Board of Public Utilities (NJBPU) RFP guidelines. Our work was organized into two Phases – Phase I: Audit of Affiliate Transactions; and Phase II: Comprehensive Management Audit.

The primary period of analysis was the three-year period from January 1, 2007 to December 31, 2009. However, depending on the subject area, we also provided historical data prior to January 1, 2007. In other instances, we included 2010 and 2011 information regarding corporate operations. However, as with any corporate organization, PSEG is continuously reviewing its corporate processes, and is subject to external events that may impact this analysis relative to present circumstances.

Overview of Audit Analysis and Summary of Key Findings and Recommendations

We found that PSEG currently has a highly qualified senior management team. Our audit identifies a number of continuing challenges facing the Company. The following represents those recommendations that we believe have the greatest potential impact in terms of financial materiality, quality of service, or regulatory compliance.

- The PSEG Corporate Governance Committee and the entire Board should consider board member nominees who possess accounting and/or regulated utility executive experience when next adding to or replacing current members. We believe that the size of the Board should be increased by one or two members to improve the diversity of expertise on the Board and to provide additional resources associated with Board responsibility. (Chapter 6)
- The President of PSE&G should be added to the PSE&G Board of Directors, consistent with general industry practice. (Chapter 6)
- During the course of the audit, Overland observed a deterioration in the relationship between PSEG and its regulators and policy makers. This is a condition that PSEG management should address and improve upon as a priority objective. (Chapter 9)
- PSE&G and PS Power should develop compliance plans for ensuring utility and PS Power personnel operate independently to the maximum extent practical. (Chapter 16)
- PSE&G should review the advantages and disadvantages of outsourcing BGSS Gas procurement to ER&T. (Chapter 16)
- PSE&G should improve its internal controls over charges to PS Power. (Chapter 17)

- PSE&G should enter into a Services Agreement with PS Power. (Chapter 17)
- PSE&G should improve its internal controls over charges from PS Power. (Chapter 17)
- PSE&G should reassess the value of its Gas Requirements Contract by either:
    - Issuing a competitive bid request for proposals to prequalified bidders, or
    - Preparing a study and cost/benefit analysis of terminating the ER&T contract and submit the study in its next BGSS proceeding. (Chapter 18)
- PSE&G should consider actions to reduce the average level of overtime, particularly for field workers, without sacrificing reliability. (Chapter 19)
- PSE&G should develop a program that prioritizes the replacement of all short sections of cast-iron pipe operating above utilization pressure. The program should have a definitive start and end date consistent with prudent distribution system risk management. (Chapter 20)
- PSE&G should conduct an in-depth study to explore the benefits of accelerating its cast-iron replacement program. The final study along with its underlying assumptions should be formally presented and discussed with the New Jersey Board of Public Utilities. (Chapter 20)
- In the short term, PSE&G should take the necessary steps to improve customer satisfaction so that it meets or exceeds levels measured prior to the iPower project implementation. In the long run, the achievement of top quartile ratings should be the goal as is the case for most operating statistics. (Chapter 22)
- On December 15, 2011 the Long Island Power Authority (LIPA) announced that it chose PSEG to operate LIPA's electric transmission and distribution system. We recommend that the implications of this agreement be given specific scrutiny in the next BPU management audit. Issues to be considered should include are the cost implications of operating the LIPA system, the potential for PSEG to cross-subsidize LIPA activities with revenues from PSE&G, and the possible diversion of utility management expertise and attention.
- Overland was restricted in our ability to analyze PSEG's unregulated operations, except to the extent that activities could be directly associated with PSE&G utility operations. Also, forecasted data was highly restricted, also greatly inhibiting our ability to assess corporate and financial planning. We recommend that the BPU Staff and the auditors selected to perform the next BPU audit of PSEG address and resolve these scope issues at the outset of the next audit.

Project Background and Scope of Audit

Request for Proposal

On April 27, 2009, the NJBPU Division of Audits issued a Request for Proposal to perform an affiliate transaction and management audit of PSE&G, PSEG and its affiliates. Overland submitted its proposal on June 12, 2009, and was ultimately selected to conduct the audit pursuant to an agreement dated October 7, 2009. Substantive work commenced in October 2009.

Project Scope

The scope of the affiliate transaction and management audits as defined by the RFPs released by the Division of Audits has generally been consistent as applied to New Jersey utilities in recent years. The Overland workplan was developed consistent with the RFP released by the BPU. The position of PSEG representatives regarding the scope of the Overland review limited our assessment of corporation operations with regard to the following areas of inquiry and analysis.

- Overland was restricted in our ability to analyze PSEG's unregulated operations, except to the extent that activities could be directly associated with PSE&G utility operations.
- Forecasted data was highly restricted, also greatly inhibiting our ability to assess corporate and financial planning.

Overland has not encountered similar restrictions in management audits of other New Jersey utilities. However, we chose not to pursue a formal process to challenge these matters in the conduct of this review. However, we recommend that the BPU Staff and the auditors selected to perform the next BPU audit of PSEG address and resolve these scope issues at the outset of the next audit. We believe that the authority of the BPU and its auditors to conduct a review across all corporate operations is well established, and arises from the Commission's Order in Docket No. EM8507774 dated January 17, 1986, which permitted the creation of PSEG. This Order references the BPU's intent to reserve the authority to review the books and records of the holding company and unregulated affiliates where potential problems may arise regarding transfer prices, cross-subsidization or anticompetitive behavior.

During the course of the audit, Overland reviewed PSEG documents that indicated an expectation of a review spanning all PSEG entities. The next management audit of PSE&G, and its affiliates should be allowed to conform with the scope of effort defined by the Division of Audits, consistent with the standard of review established in the conduct of other New Jersey utilities.

Approach to the Project

Initial Meeting with BPU Staff and Rate Counsel

Prior to finalizing our project workplans and commencing the technical analysis, Overland met with representatives of the BPU Staff and the New Jersey Rate Counsel. This meeting addressed various concerns about PSE&G that the parties felt were within the intended scope of our review. This meeting allowed Overland the opportunity to assure that our analysis would incorporate any legitimate issues that were of concern to these public entities.

Conduct of Interviews

The audit review was facilitated by the conduct of informal interviews with company personnel, including subject matter experts, senior management and the PSEG Board of Directors. Most of these interviews were conducted on-site at various locations within the PSEG service area with the primary site being the PSEG headquarters in downtown Newark, New Jersey.

The interviews were considered "informal", as they were not taken under oath and there was no transcript taken or recording made. In a number of instances, no attorneys were present. Aside from the Overland representative and the company interviewee, the company generally had one or two individuals present who were assigned to support the audit process. The primary purpose of the interviews was to gain an understanding of corporate operations, and to identify and clarify documents and reports available to support our technical analysis. To the extent possible, Overland did not rely directly on the information gathered in interviews. Written data requests were used as the primary basis for our analysis, findings and conclusions.

Overland interviewed several members of the PSEG Board of Directors. While it appeared that company representatives had briefed each director on the subject matter likely to be covered in the interview, we were generally able to elicit information and opinions concerning matters relevant to our review of the company.

A complete list of the 66 interviews conducted by Overland is provided in Attachment 1-1.

Written Discovery

Overland developed written discovery requests as the primary basis for its technical analysis, which is relied upon in the development of this report. Over the course of our audit, Overland issued 1,506 data requests. Many of the documents produced were classified as confidential by the company. Certain information was further classified as “Restricted” or “Restricted on-site only” material, which was provided under more limited conditions. Overland believes that the classification and limitations placed on the material produced was generally justified, and that the procedures agreed upon with regard to this material actually facilitated our work by providing reasonable access to highly sensitive material requested during the audit.

Other Sources of Material Relied Upon

Overland also reviewed documents from sources external to the written discovery and interview process described above. We have reviewed: financial material from various sources including investment services and rating agency publications, New Jersey BPU reports and Orders relevant to the PSE&G audit, and industry publications in the public domain. To the extent that this information was relied upon in our report, we have identified it in our footnoted references.

Review of Draft Report

Prior to the release of our report, an intense review process was imposed to ensure a complete, balanced and accurate presentation of our analysis. Aside from the internal review of the work product, Overland solicited and considered the comments of both BPU staff and PSEG prior to the release of this final audit report. Overland made an independent determination of whether to modify our report based on the comments provided. The review and comment process involving PSEG was focused on factual accuracy of the document. An exit conference with PSEG was held upon a review of the final draft. This review process occurred over a nine to ten month period, culminating shortly before the report release.

PSEG and Business Unit Overview

PSEG is a diversified energy company primarily engaged in competitive energy generation, sales, supply, trading, marketing, and risk management (competitive); and electricity and natural gas delivery (regulated services). Headquartered in Newark, New Jersey, it is one of the ten largest electricity providers in the United States. Its principal businesses include:

- Power – The power business integrates power generation with wholesale energy sales, fuel supply, and energy trading and risk management. Power, natural gas, capacity and emissions and congestion credits are principal sources of revenue. Through its Power segment subsidiaries, PSEG owns approximately 13,600 MW of generating capacity in the Northeast and Mid-Atlantic regions.

- Regulated Transmission and Distribution – Regulated T&D is PSEG's largest business. PSE&G is one of the largest combined electric and natural gas utilities in the U.S., currently providing electric service to approximately 2.1 million customers and gas service to 1.7 million customers. PSE&G's electric and gas service territories cover an area where approximately 70 percent of New Jersey's population lives.

- Energy Holdings – The Energy Holdings business owns passive energy-related investments, including energy-related leveraged leases, and 2,400 MW of generating capacity, primarily in Texas.

- PSEG Services Corporation (PSEG Services) – PSEG Services includes approximately 1,000 employees who provide management and administrative services to PSEG's subsidiaries. These include traditional corporate services such as executive management, legal, accounting, treasury, planning, finance and accounting, corporate development and communications, risk management, human resources, and internal audit. PSEG Services also provides operating management and administrative services, including supply chain and transportation management and information technology services. These services are provided pursuant to a service agreement, and are charged to PSE&G and other subsidiaries based on costing methodologies set forth in the agreement. PSEG Services' costs directly charged or allocated to PSE&G for the years ended December 31, 2009, 2008 and 2007 were $240 million, $264 million and $238 million, respectively.

As noted above, with 2.1 million customers and a service territory that covers a majority of New Jersey, PSE&G is one the nation's largest investor-owned utilities. However, as shown in the table below, compared with PSE&G's regulated utility business, the Power business has been far more profitable in recent years.

Table 1 -1 - PSEG Earnings and (Losses), in millions

PSEG Earnings and (Losses), in millions			
Segment	**2007**	**2008**	**2009**
Utility segment	380	364	325
Power segment	1,000	1,115	1,189
Energy Holdings segment	12	(468)	72
Other	(67)	(28)	6
PSEG Total	**1,325**	**983**	**1,592**
Source: SEC Form 10K, Year 2009			

Affiliate Overview (Chapter 2)

The Affiliate Overview chapter contains a summary of findings for all chapters covering affiliate transactions. The findings summarized here are limited to those unique to Chapter 2.

EDECA Affiliates

During the review period PSE&G had two minor affiliates classified as "affected affiliates" under the Electric Discount and Energy Competition Act Affiliate Standards (EDECA). Demand Management Company is a two-employee operation that earns income by sharing electricity savings with customers from the installation of energy efficiency equipment. PSEG Solar Source has five employees. In 2010 it operated solar generation equipment for three facilities, one of which was in New Jersey. Approximately 2 MW out of Solar Source's 29 MW of operational capacity in 2010 was located in New Jersey at the Mars Snack Food plant in Hackettstown. The remaining 27 MW was located in Ohio and Florida. PSE&G's compliance with the EDECA rules with respect to these two minor affiliates is discussed in its Compliance Plan. Overland found nothing during the audit to indicate that PSE&G was not compliant with EDECA with respect to these affiliates. (2-14 to 2-16)

Prior EDECA Audit Recommendations

Six of twenty-four recommendations made in the prior EDECA audit were contested according to the company or the BPU. The disposition of these recommendations was never formally resolved. Some of the recommendations are no longer relevant eight years after being made, but two continue to remain outstanding. In implementing a recommendation made in the prior EDECA audit, an affiliate did not pay all of the accumulated interest it owed to PSE&G. However, this unreimbursed interest only amounted to approximately $8,000 through the end of 2010. (2-16 to 2-22)

PSEG Services (Chapter 3)

Internal Control - Control over service company budgeting, accounting and cost distributions during the review period (2007 through 2009) was adequate to inhibit significant opportunities for cross-subsidization of non-regulated Power and Holdings operations by PSE&G. The operating companies, including PSE&G, participated in the annual service company planning and budgeting process. This provides the operating companies the opportunity to provide input into the level and cost of services billed to them by the service company. We found that in most cases, services are designed to measure and track the cost of activities. Activity-based costing facilitates the proper assignment of cost to cost-objectives and is an important component of an attribution-based cost distribution process. We found that services were segregated by degree of control to provide the operating companies and lines of business the ability to scale service levels to their needs. In most cases, pricing methods established causal links between the activities performed by the service company and the operating companies (OCs) receiving the services. Service prices were designed to recover costs on a fully-distributed basis, meaning that the prices included applicable labor loadings and service company overheads and were designed to recover, as a group, all incurred service company costs. The percentage of costs distributed using "unattributable" size-based allocators (Enterprise costs) was relatively low and appears to be decreasing as refinements in the analysis and pricing of services continues.

Changes in Enterprise Cost Allocation Methods - In 2009 the service company reduced the number of methods used to distribute Enterprise costs (costs incurred on behalf of the corporation as a whole) from four to one. Specifically, "modified Massachusetts", "revenue-earnings-capX", "headcount" and "Law department historical experience" allocation methods were replaced by a single consolidated method that allocates costs based on a composite of net fixed assets, headcount and O&M expense. The change had little impact on the percentage of Enterprise costs allocated to the Utility and Power OCs (PSE&G's share of Enterprise costs increased from 55.3 percent in 2008 to 56.0 percent in 2009). However, the increased importance of headcount and assets under the new method, both of which are lacking in the Holdings OC, cut allocations to Holdings by more than half. Specifically, Holdings' share of Enterprise costs decreased from 2.3 percent in 2008 to 1.0 percent in 2009, and Enterprise costs allocated to Holdings decreased from $1.6 million in 2008 to $688,000 in 2009.

Reductions in the Enterprise Cost Pool / Reductions in Costs Allocated to Holdings – 2008 cost reclassifications reduced the percentage of costs classified as unattributable Enterprise costs. Specifically, the percentage of service company costs included in the Enterprise cost pool decreased from $81.0 million (20 percent of service company charges) in 2007 to $72.4 million (16 percent of service company charges) in 2008.[1] In percentage terms, the Holdings OC was by far the largest beneficiary of the change. Allocations of Enterprise costs to Holdings dropped from $3.6 million in 2007 to $1.6 million in 2008.

Incurred Service Company Costs - Service company costs did not increase significantly during the review period. Costs were $402 million in 2007 and $416 million in 2009. A higher level of cost in 2008 ($451 million) can be attributed primarily to costs incurred to implement PSE&G's new iPower (customer service) system. 2009 was lower due primarily to completion of the new customer service system and the transfer of approximately $21 million in Environmental, Health and Safety services out of the service company.

Refinements and Changes in Pricing and Cost Allocation Procedures – PSEG Services made various changes in pricing and allocation procedures during the audit period. These had a relatively minor impact on the distribution of service company costs between 2007 and 2009. The percentage of costs charged to PSE&G remained steady at approximately 59 percent. Costs billed to the Power OC increased from 35.7 percent to 37.5 percent. The Holdings OC was the largest beneficiary of the changes. Charges to Holdings dropped by about one-fourth, from $20.2 million to $15.6 million, despite a small overall increase in total costs billed out by the service company. When viewed from the perspective of total distributed cost, and in the context of the procedures and controls in place, we do not believe the changes and refinements made during the review period are a cause for concern.

Recommendation

1. Whenever possible, costs from the service company's Internal Audit professional services should be directly charged based on the "clients" for whom audits are performed. Although professional internal audit services appear to be charged at an hourly rate as a professional service, the distribution of audit services among operating companies from year to year during the review period was virtually identical (e.g. 53 percent PSE&G in 2007, 55 percent in 2008 and 56 percent in 2009) and very close to the Enterprise allocator, suggesting that a type of size-based allocation factor is driving the charges. It is appropriate to charge "corporate" audits benefiting the corporation as a whole using a size-based factor such as the Enterprise allocator. However, many audits are performed specifically for the benefit of particular operating companies and segments. Time should be charged to each audit, and the cost of the audit should be billed to the appropriate

[1] In 2009, Enterprise costs were $69.1 million (17 percent of service company charges).

operating company "client," just as it would if it were provided by an outside professional service provider.

Appliance Services (Chapter 4)

The Appliance Service Business (ASB) is part of the Utility (PSE&G) operating company and legal entity. Most of the resources used by the ASB are also used by and integrated with PSE&G (i.e. technicians, vehicles, facilities, support services, etc.). Most internal activities involving the ASB are technically not affiliate transactions because they occur within PSE&G. However, because appliance services are competitive and are not restricted by prices established by regulators in rate proceedings, they can be subsidized by services that are rate-regulated. As such, PSE&G remains subject to the competitive services rules set forth in the BPU's Affiliate Standards. (4-2 to 4-3)

PSE&G annually trains employees in Appliance Services on the Affiliate Standards. Appliance service technicians are trained on how to provide service to customers in a non-discriminatory manner. They are also trained to properly record their tasks through job codes to prevent cross-subsidization between tariffed and non-tariffed activities and costs. (4-4)

ASB's financial results show that it operated with pre-tax margin of no less than 21% during the 2007-2009 audit period. We reviewed the costs attributed to the ASB and determined that appropriate categories of direct and indirect operating costs and appropriate overheads were attributed to the ASB. Thus, Overland concludes that as a business, ASB charged prices sufficiently high to exceed its fully allocated cost of providing services. (4-7 to 4-8)

The ASB has several competitive advantages over its local appliance services competitors. These include affiliation with PSE&G and the utility's recognized brand and logo, economies of scale, access to the utility's billing envelope for advertising purposes, use of the customer information system, and use of the utility's customer call center. There are also a few competitive disadvantages, including association with the utility's monopolistic type of business, rate restrictions and Affiliate Standards, and the incurrence of corporate overhead costs associated with the utility holding company. Overland was not able to determine if the ASB was charged for using the utility's logo and brand. (4-12 to 4-13)

Although the ASB's prices were high enough overall to conclude that the business was not being cross-subsidized by rate-regulated utility services, we found that the ASB's floor rates were not high enough to recover the fully allocated cost of providing appliance repair contracts and services in 2009. The hourly service floor rate was $190 in 2009 and increased to $230 in 2010. In 2009 the $190 hourly service rate charged by the ASB was less than the fully allocated costs for the HVAC (Heating, Ventilation, and Air Conditioning) and APSO (Appliance Parts and Service Orders) product lines within the ASB. However, appliance service revenue per hour was significantly *higher* than floor price and fully allocated cost. Furthermore, the floor rate was lower than fully allocated costs for 4 of the 18 types of appliance service contracts in 2009 (cooktop, clothes dryer, clothes washer, and dishwasher). However, the amount charged for the category contract repairs was significantly higher than both the floor price and the fully allocated cost to provide the contracted service. PSE&G completed its ASB financial reporting process and filing with the BPU in February 2010 and issued a revision to the competitive services tariffs, which increased the floor rate to $230 per hour, so that it exceeded the 2009 fully allocated cost of providing appliance services. The revised tariff was effective on March 24, 2010. (4-8 to 4-11)

Recommendation

1. PSE&G should monitor its fully allocated cost per hour on a more frequent basis (e.g. monthly or quarterly) to ensure that its floor price covers the fully allocated cost of providing appliance services, thereby ensuring continuous compliance with EDECA standards.

Organizational Structure (Including Nuclear Operations) (Chapter 5)

PSEG's management organization is structured to serve the four major operating subsidiaries, with a heavy emphasis on the utility, Public Service Electric and Gas (PSE&G). PSE&G accounts for approximately 61 percent of PSEG employees. PSEG Power accounts for approximately 28 percent of employee resources. In addition to its operating subsidiaries in fossil and nuclear energy, PSEG Power also contains an energy trading function called PSEG Energy Resources & Trade. PSEG Services Corporation accounts for approximately 10 percent of PSEG employees and includes the senior executives of PSEG. Lastly, PSEG Energy Holdings accounts for 1 percent of PSEG employees. This subsidiary contains two unregulated organizations: PSEG Global and PSEG Resources. (5-1 to 5-2)

PSEG Nuclear is a PS Power subsidiary that is looking to potentially expand in the future. The nuclear division already wholly owns one nuclear generating station and has part ownership in two others. In the time subsequent to our audit, PSEG Nuclear has filed an application for an Early Site Permit with the Nuclear Regulatory Commission to build a new nuclear reactor. PSEG also has plans to invest nearly $600 million in upgrading its existing nuclear facilities within the next five years. (5-7 to 5-8)

Executive Management and Corporate Governance (Chapter 6)

We generally found the PSEG Board of Directors to be comprised of an acceptable mix of expertise and experience relevant to oversight of corporate planning, reporting, and operations. The PSEG Board of Directors has a strong independent presence, supported by an experienced lead independent director. The remaining directors on the Board are all independent, except for the Chairman, who is the CEO of PSEG.

Key Recommendations:

- Overland recommends the PSEG Corporate Governance Committee and the entire Board consider board member nominees who possess accounting and/or regulated utility executive experience when next adding to or replacing current members. We believe that the size of the board should be increased by one or two members to improve the diversity of expertise on the board and to provide additional resources associated with Board responsibility.

- The President of PSE&G should be added to the PSE&G Board of Directors, consistent with general industry practice for the composition of utility subsidiary boards.

- Reassess the weightings assigned to incentive compensation goals for utility executives so that non-financial objectives are given more emphasis. In addition, consider the establishment of a threshold that must be achieved for non-financial objectives before executive incentive compensation is paid.

Board Compensation and Stock Ownership

The Corporate Governance Committee retained outside consultants from Mercer to provide analysis, information and advice on the level of compensation for the directors who are not executive officers. Mercer's report showed that director compensation at PSEG is competitive with its peer group. During the period of the audit, each director was required to own 4,000 shares of PSEG common stock within three years of being elected to the Board. Of the companies listed in PSEG's peer group according to its 2008 Proxy Statement, the requirement for PSEG's directors appears to be on the lower end of the stock ownership requirement for the directors of the peer group companies. (6-10 to 6-16)

Executive Management

PSEG and its subsidiaries are governed by a select group of senior officers, who are a part of what PSEG designates as the Executive Officer Group (EOG). As of March 2010, this group of senior officers was: Mr. Ralph Izzo, Chairman, President, and CEO; Ms. Caroline Dorsa, EVP and CFO; Mr. Derek DiRisio, Controller; Mr. J.A. "Lon" Bouknight, Jr., EVP and General Counsel; Mr. Randall E. Mehrberg, EVP – Strategy and Development; plus the presidents of PSEG Power, PSEG Energy Holdings, PSE&G, and PSEG Services Corporation. Members of the EOG, including the senior officers, meet to report on and discuss policies, initiatives, issues, and developments pertaining to the economics, operations, and business objectives of the subsidiaries and the enterprise generally. (6-23)

Succession Planning

PSEG has a process for succession planning that includes its executive management positions. The plan for each position is reviewed by the EOG each year. Potential successors can be identified as: Ready Now, Ready in 1-2 years, or Ready in 3-5 years. Of the fifteen most senior positions at PSEG and PSE&G in November 2010, only one-third of them had a "ready now" succession candidate or were in a position that would be realigned in a subsequent reorganization if a sudden vacancy occurred. (6-23 to 6-24)

Executive Compensation

In designing an executive compensation program, total direct compensation (consisting of salary and short-term and long-term incentive compensation) is the focus rather than individual components. The company targets the median of compensation of similar positions within an identified peer group of energy companies adjusted for performance and experience. (6-24 to 6-26)

While it would not be appropriate to draw any definitive conclusions about the reasonableness of PSEG's executive compensation by comparing it to other New Jersey utilities because of the differences in corporate size, executive tenure, and executive experience; PSEG's named executive officers were all expected to be compensated within a reasonable range of the competitive median in 2010. (6-30 to 6-33)

PSEG executives' short and long-term incentive compensation was highly dependent on the achievement of financial goals. (6-27 to 6-31)

Sarbanes-Oxley Compliance

Neither PSEG nor PSE&G identified any material weaknesses in internal controls over financial reporting as of year-end in 2008 or 2009, and the external auditors issued unqualified opinions on PSEG's internal control assessments for these two dates.

Ethics and Compliance

PSEG uses a governing document entitled "Business Conduct Compliance Program" (BCCP) to provide guidance in carrying out an effective ethics and compliance program. The Executive Officer Group (EOG) has overall responsibility for the BCCP and its implementation; however PSEG has created a Compliance Council that has more specific oversight responsibility for the BCCP. Hugh Mahoney serves as the General Compliance Counsel to the Council. (6-33)

An assessment of the Compliance function was completed by Peter Veniero of Sills, Cummis, and Gross in 2007. One of the recommendations from the assessment was that the person that has day-to-day guidance of the Compliance function should be more visible in the leadership of the company, the organization chart and among employees. This led to Mr. Mahoney beginning to make regular presentations to the Audit Committee in 2008. (6-33)

The Ethics and Compliance function at PSEG has an Integrity Line where employees can disclose any observances or complaints regarding accounting, auditing, and internal control matters; any misappropriation of company assets or proprietary information; and any violation of company or government laws and regulations. PSEG initiates approximately 200 compliance cases per year that originate from the Integrity Line. (6-36)

Risk Management (Chapter 7)

The Risk Management Committee (RMC) is responsible for setting the level of risk that the company is willing to accept. The RMC is governed by a charter and reports directly to the Audit Committee and Finance Committee of the PSEG Board of Directors. The Enterprise Risk Management Department (ERMD) is responsible for identifying areas within the organization where risks are created and putting in place processes to assure that these risks are regularly measured on a consistent basis. The Chief Risk Officer is the lead for the ERMD and reports directly to the CFO of PSEG. (7-1 to 7-2)

The Risk Management Department has transitioned from a financial risk management focus to a broader "enterprise" risk management focus over the past five years by expanding the PSEG-wide focus encompassing the improvement of existing processes through a joint effort of various organizations across PSEG. The Risk Management function at PSEG was reviewed by PriceWaterhouseCoopers (PWC) in 2008. PWC made a few recommendations as a result of their analysis. These recommendations were:

- Hire a PhD level lead quantitative resource with energy commodity experience.
- Document the relationships between the risk functions in the different operating companies.
- Move the ER&T middle and back office functions to an independent function or controller group.
- In ER&T Compliance and Controls, distinguish the roles of compliance advisor and independent compliance monitor.

PSEG implemented these recommendations through the following actions:

- PSEG hired a Senior Quantitative Analyst with the recommended qualifications in January 2009.
- PSEG combined the different operating companies' risk functions into the RMC.
- PSEG moved the ER&T middle and back office functions to the Services Company.
- PSEG moved the ER&T compliance function to the ERMD and kept the advisory function in the ER&T business unit. (7-4 to 7-6)

Strategic Planning (Chapter 8)

PSEG's strategic plan is to grow an operationally excellent, integrated generation, transmission, and distribution business in competitive and/or carbon-constrained domestic markets. This strategic plan is developed and refined by the Executive Officer Group. The strategic planning process is centrally coordinated between three operating entities (PSE&G, PSEG Power and PSEG Energy Holdings). (8-1 to 8-2)

The strategic planning function has two components: Corporate Strategy and Emerging Technologies and Technology Transfer. Corporate Strategy is responsible for leading any strategic studies done by PSEG and creating the five-year business plan that is presented to the Board of Directors. The Emerging Technologies and Technology Transfer group works with the utility on short-term system monitoring and long-term technology developments. (8-3 to 8-4).

While there has been consistent activity in mergers and acquisitions within the utility industry, PSEG has not been active in considering utility acquisitions. Rather, it has been seeking opportunities to acquire assets, specifically generating assets, as a means of expansion. It is management's view that utility acquisitions are unlikely to create meaningful value to shareholders, absent known synergies that can be retained by the shareholders. (8-7 to 8-8)

PSEG is actively involved in federal and state energy policies and programs that help its customers reduce their energy consumption. PSEG invests in renewable energy projects as well as green energy initiatives to combat the effects of climate change and global warming. (8-8)

PSEG Commitment to Non-Regulated Business Units. Like many other utility holding companies, PSEG has investments in generating assets and regulated utility transmission and distribution operations. PSEG has two major subsidiaries that fall into the category of non-regulated business units: PSEG ER&T and PSEG Energy Holdings. PSEG Energy Holdings maintains a portfolio of international leveraged lease investments as well as a few domestic generation investments. PSE&G has operations that are not directly related to its utility operations. These operations are maintained for economic development and financing purposes and contain assets worth approximately $23 million. (8-8 to 8-11)

PSEG uses the SWOT (strengths, weaknesses, opportunities, and threats) analysis as a tool for strategic planning. PSEG believes that its strengths are its assets, location and consistent operating cash flows, while its weaknesses pertain to the aging of its assets, specifically employee resources and infrastructure. PSEG also noted several opportunities and threats that could enhance its strengths or further expose its weaknesses. (8-11 to 8-13)

External Relations (Chapter 9)

The External Relations function is comprised of four separate business units at PSEG: State Governmental Affairs, Federal Affairs, Policy and Environment, Health and Safety and Corporate Social Responsibility and Sustainability. PSEG has placed a high emphasis on sustainability programs to the point of earning EEI's Edison Award for 2010 "in recognition of its bold and innovative growth strategy geared toward clean energy, energy efficiency, and job creation". (9-1, 9-7 to 9-8)

This function experienced some changes in the past few years. PSEG determined that this function was a better fit under the Strategy and Development group and moved it there from the General Counsel group in 2009 following an analysis of the External Relations function. The External Relations group has grown from approximately 50 employees to about 60 employees during 2010. (9-2)

PSEG's External Relations department takes part in a benchmarking study through the Public Affairs Council. The study included utility companies as well as companies in other industries. Compared to these other companies, PSEG has a fairly large external relations group. According to the 2008 study, PSEG had 56 employees in its public affairs group, while the median company in the study had only 22. Also in the study, PSEG had a public affairs budget of two to three times the median. (9-4)

The State Governmental Affairs has four core functions: advocacy, corporate responsibility, public affairs & policy support, and the PSEG Foundation. The Federal Affairs and Policy core functions are: public policy development, congressional and federal relations, and state relations outside of New Jersey. These two groups have registered lobbyists and other employees that regularly meet with legislators and government administrators to address matters that are important to PSEG. Both groups also use outside lobbyists to help them meet their objectives. In 2009 PSEG spent more than $1 million in outside lobbying services for federal governmental affairs and approximately $500,000 at the state level. PSEG also spent over $500,000 in environmental lobbying services in 2009. Both the state and federal groups place a high emphasis on sustainability programs in the energy sector in the specific areas of clean energy, energy efficiency, and job creation. (9-4 to 9-13)

The PSEG Foundation provides programs and assistance supporting PSEG's three priority areas of giving: education, environment, and community and economic development. Although, contributions from PSEG to the Foundation have been generally increasing, PSEG's corporate contributions are consistently less than its peers on a pre-tax income basis. (9-13 to 9-14)

PSEG is committed to community development and outreach. The Community Development group communicates with its stakeholders via a monthly newsletter within PSEG and outside the company. (9-14 to 9-15)

There are several initiatives that the External Relations department will look to implement in the future. For the entire corporation, these initiatives are centered on the topics of: national transmission policy, climate change, dividend tax rates, and competitive markets. For the operating companies (utility and power affiliates), these initiatives are centered on the topics of: nuclear support, base rate case, Susquehanna-Roseland Line, coal combustion by-product, offshore renewable energy credits, cooling towers, over-the-counter trading rules, emission credits trading, and support for compressed air energy storage. (9-16 to 9-18)

Key Recommendations:

- Overland observed that all of the metrics for the External Affairs function were met, except one in 2009. We recommend that PSEG review its External Relations metrics and incorporate stretch goals into their benchmarks in the balanced scorecards in the future.
- PSEG should increase its annual level of contributions to the PSEG Foundation as it is consistently below the median amount of corporate foundation giving amongst its peers.
- A critical asset for any regulated utility is a positive relationship between it and its regulations and policy makers. During the course of the audit, Overland observed a deterioration in these relationships, a condition the PSEG management should address and improve on as a priority objective.

Finance (Chapter 10)

Credit Ratings

PSEG and PSE&G's credit ratings have been generally stable during the audit period. Both PSEG and PSE&G have the goal of maintaining or improving their credit rating. PSE&G specifically has an objective to keep their secured debt credit rating at the "A" level. Both PSEG and PSE&G have maintained investment grade ratings throughout the audit period.

Both PSEG and PSE&G maintained stable credit ratings in 2009 according to S&P and Moody's. S&P rated PSEG and PSE&G BBB on their corporate credit rating. Moody's rated PSEG Baa2 on its corporate credit rating and PSE&G Baa1 on its corporate credit rating. (10-13 to 10-15)

Dividend Policy

As a wholly-owned subsidiary of PSEG, PSE&G's common stock is not publicly traded. PSE&G uses its earnings, dividends to PSEG and capital infusions from PSEG to manage its equity ratios and also indirectly, its credit ratings. (10-2, 10-5)

PSEG's dividend policy is set by the Finance Committee of the PSEG Board. The policy has objectives that are targeted by the committee to ensure the financial stability of the company. The objectives include: achieving a payout ratio range of 40% - 50%, meeting the dividend expectations of the financial community, providing a competitive yield when compared to PSEG's peer group and maintaining PSEG's long-term earnings profile. PSEG's actual dividend payout ratio from 2007 to 2009 (45%, 55%, and 42%) was comparable to its peers and in line with its objectives. As mentioned above, PSE&G pays dividends to PSEG in an amount that allows the utility to comply with its capital structure policy. (10-4 to 10-6)

Cost of Capital and Capital Structure

PSEG's cost of equity was compared to that of its utility peers, both those with predominantly regulated operations and those with predominantly unregulated operations. PSEG's cost of equity was more aligned with those utility companies with predominantly unregulated operations. The comparison is considered reasonable as more than 70% of PSEG's operating income from 2007 to 2009 was from PSEG Power, which is an unregulated subsidiary of PSEG. PSE&G's target capital structure and cost of equity is established in rate cases, the most recent of which occurred in 2009. In that rate case, PSE&G sponsored a capital structure with a target equity ratio of 51.2% and a cost of equity of 11.5%. The utility has had an equity ratio of 53% or higher during most of the audit period. The cost of equity authorized in the settlement of the most recent rate case was 10.3%. (10-6 to 10-10)

All of PSEG's debt is held at the subsidiary level. Approximately 70 percent of PSE&G's debt is scheduled to mature within 10 years. The utility issues its debt through public placement as this method has the most liquid market and lowest debt issuance costs. (10-10 to 10-12)

Other

PSEG has collateral requirements for both its regulated and unregulated businesses. Substantially all of the regulated utility's assets are pledged under the utility's First and Refunding Mortgage. Any third party encumbrances on regulated business assets are subordinate to the First and Refunding Mortgage. PSEG Power, an unregulated business, unconditionally guarantees payments for its subsidiaries to help them obtain more favorable credit ratings. PSEG Power is also required to post collateral or margin on commodity-related contracts. PSEG Energy Holdings, another unregulated business, has collateral pledged in the form of letters of credit. (10-16 to 10-17)

PSEG management believes it has taken the necessary steps to insulate PSE&G from the potential financial difficulties of its non-regulated affiliates, which include both structural separation and restrictions related to cross-subsidization. An example of the former is PSE&G's non-participation in the PSEG money pool. (10-17 to 10-18)

During the credit market crisis in the latter half of 2008, PSE&G was able to continue accessing the capital markets. This was evidenced by the issuance of $275 million of debt in December 2008. (10-18 to 10-19)

PSE&G supplements its day-to-day working capital needs with a $600 million syndicated credit facility. From January 2008 to October 2009, the maximum amount of commercial paper outstanding under this facility was $485 million. (10-19 to 10-21)

PSEG Resources LLC, which is a wholly-owned subsidiary of PSEG Energy Holdings LLC, has entered into several leveraged leases. The deductions for these leases were disallowed by the IRS from 1997-2003.

PSEG has filed a protest of the IRS's position and has made a diligent effort to divest its interests in the leveraged leases.

PSEG also took an impairment charge in the second quarter of 2008 related to these leases due to the change in projected cash flows. The charge that PSEG took was $485 million before tax and $355 million after tax. PSEG believes that if it were unable to successfully defend its position in the matter, it would have to record an additional impairment charge of $100 to $120 million. During 2009, PSEG sold its interests in 14 leveraged leases, 12 whose prior years' deductions had been disallowed by the IRS. Proceeds from the sales were $830 million and the after-tax gain was $70 million. As of December 31, 2009, PSEG's total gross investment in its remaining leverage lease interests was $347 million. (10-22 to 10-23)

Rates and Regulation (Chapter 11)

Regulatory Organization

During the time period subsequent to our audit, the PSE&G Corporate Rate Counsel (CRC) was split into two groups. The legal function of the CRC was shifted to PSEG's Law Department, while the finance group within the CRC was merged with PSE&G's finance group. (11-1 to 11-3)

PSE&G monitors the electric and gas delivery rates that are charged to its customers by comparing them to the rates charged by other utility companies in its peer group. For all types of customers (commercial, industrial, and residential) and for both electric and gas rates, PSE&G customers have rates that are very competitive when compared to PSE&G's peer group. (11-3 to 11-7)

Rate Case Filings

On May 29, 2009, PSE&G filed its request with the NJBPU for an increase in electric and gas base rates. The request called for a $134 million or 1.93% increase in electric distribution revenues, a $97 million or 2.95% increase in gas distribution revenues, and other peripheral requests. In the summer of 2010, the BPU approved a $73.5 million increase in electric rates and a $26.5 million increase in gas delivery rates. S&P and Moody's viewed the outcomes as favorable, while PSEG management and its Board were was disappointed with the BPU's decision. This disparity in the reaction of the financial community and the negative view of PSEG senior executives and the Board, raises serious questions regarding the process necessary to evaluate reasonable outcomes on the basis of key components supporting the rate filings. (11-7 to 11-8)

Morris Energy Group Order

The Morris Energy Group and the New Jersey Large Energy Users Coalition entered into a supplemental proceeding in the rate case filing to address certain specific issues. These issues concerned tariff rates, rate discrimination, and the societal benefits charge. In December 2010, these issues were settled by the parties mentioned above and PSEG, and the settlement was approved by the NJBPU. (11-8 to 11-9)

Cost Recovery Mechanisms

The BPU has permitted PSE&G to recover the costs of certain programs outside the context of base rate case proceedings. Examples of such programs are those that encourage energy efficiency, investment in renewable energy, and economic activity in the state of New Jersey. In the limited detail disclosed to us, we observed no costs that fell outside the broadly-defined scope of these programs. (11-9 to 11-17)

Since the beginning of 2008, the company asserts that it has not deferred any prior year costs in any of its cost recovery mechanisms. This was a point of contention between the company and other parties in the past. Overland did not independently verify the company's assertion. (11-10 to 11-11)

The most significant non-rate related revenues in recent years are associated with tax gross-ups on contributions in aid of construction, the required offset to amortization of Repair Allowance & Restructuring, and gains and losses on sales of property. While the company proposed to share with ratepayers one-half of gains on the sale of property based on a five-year average in its most recent electric and gas rate filings, overall rates were subject to a settlement which was silent on the matter of gains sharing. (11-17 to 11-21)

Accounting and Property Records (Chapter 12)

PSE&G's accounting is largely handled by PSEG Services Corporation under the direction of the corporate CFO, using a third-party software platform designed by SAP. The performance of the accounting-related departments as measured against balanced scorecards generally exceeded management expectations during the time period we reviewed. However, PSEG was trailing top performers in controlling payroll processing costs according to 2008 benchmarking results. (12-3 to 12-15)

Internal controls over financial reporting are the subject of extensive review by the Internal Audit Department (now reporting administratively to the CFO), the Internal Controls group, and the external auditors – Deloitte & Touche. Neither PSEG nor PSE&G identified any significant deficiencies or material weaknesses with internal control over financial reporting for the years 2007 through 2009, and Deloitte & Touche opined that PSEG maintained effective internal controls over financial reporting during this same time period. Likewise, Sarbanes-Oxley testing results showed year-over-year improvement in the number of total internal control failures identified and those that remained unremediated at year-end. (12-16 to 12-22)

PSE&G has not recorded any asset impairments since the beginning of 2007, and those impairments recorded by affiliates have been relatively insignificant to overall consolidated earnings. (12-24 to 12-25)

Key Recommendations:

- Re-align the Internal Auditing Services group so that it reports administratively to the PSEG CEO rather than the CFO. By doing so, the company would conform to industry guidance and promote the appearance of independence.

- Provide the BPU a cost estimate and periodic updates concerning the remediation of a significant control weakness associated with manual non-purchase order checks which has been outstanding for an extended period of time.

Power Supply Management (Chapter 13)

PSE&G spends $3.5 billion a year on purchased power. The power markets are subject to considerable uncertainty. Concerns about wholesale market design and high prices have halted the trend towards deregulation in the United States. (13-2 to 13-3)

Power supply management should be a priority for PSE&G. PSE&G does not devote sufficient resources to power supply management. PSE&G's power supply function does not have adequate management direction or oversight.

PSE&G's power supply objectives are to: (1) purchase power at prices consistent with competitive market conditions; (2) provide a modest level of price stability; and (3) protect the company against supplier defaults. (13-19)

PSE&G's overall strategy is to: (1) purchase default supply in the BGS auctions; (2) sell the power it buys under NUG contracts into PJM markets; and (3) comply with BPU directives concerning demand response, renewable generation and energy efficiency.

PSE&G is opposed to using long-term contracts and utility-owned generation for default supply. PSE&G views those as uneconomic state intervention into competitive markets. Transmission enhancements can reduce energy and capacity prices by reducing transmission constraints. PSE&G is opposed to PJM's economic transmission planning process.

PSE&G's Energy Acquisition Group (EAG) is responsible for default supply procurement. The Transmission Business Strategy Group (TBSG) is responsible for managing PJM and FERC market design issues. The Electric Delivery Planning Group (EDPG) is responsible for transmission system planning. None of those groups are adequately staffed. The EAG does not have the staffing needed to identify and assess least-cost power procurement strategies for default supply customers. The TBSG does not have the staffing needed to independently analyze PJM market rules and promote the interests of BGS customers at PJM or FERC. The EDPG does not have the staffing needed to prepare economic planning studies of transmission enhancements. (13-20 to 13-25)

PSE&G does not prepare power supply plans. PSE&G does not analyze power supply alternatives or market conditions. PSE&G does not undertake any meaningful analysis of power supply issues. (13-25 to 13-26)

Demand Response, Energy Efficiency and Renewable Generation (Chapter 14)

PSE&G's only demand response program is an air conditioning cycling program for residential and small commercial customers. The cycling program currently has a capacity value of about 62 MW. PSE&G is expanding the program to 192 MW. (14-12 to 14-13)

PSE&G does not have any plans or strategies for promoting participation in PJM demand response programs. PSE&G's BPU filings are the only documentation of its demand response plans and strategies. (14-5)

PJM has two basic types of demand response programs, capacity and energy. (14-5)

PSE&G has been highly critical of PJM's capacity program. According to PSE&G, the capacity program provides substantial payments to participants "for doing very little without incurring very much risk." PSE&G recommends eliminating the PJM capacity program. (14-10)

PSE&G also recommends: (1) reducing the amount of capacity that can participate in the capacity program; and (2) stricter qualification and verification requirements for demand response resources. (14-11)

The PJM demand response capacity program has three different products; (1) Limited DR; (2) Extended Summer DR and (4) Annual DR. PJM believes the Extended Summer DR product is a good fit for air conditioning cycling programs. PSE&G currently bids its cycling program as a Limited DR product. Extended Summer DR products can potentially receive higher reliability pricing model (RPM) capacity prices than Limited DR products. PSE&G should consider qualifying its cycling programs as an Extended Summer DR resource. (14-5 to 14-12)

Participation levels in PJM's economic demand response program are very low. The FERC recommended increasing the compensation paid to economic program participants in March 2010. PSE&G opposed that recommendation. PSE&G has not analyzed the factors impacting economic program participation or the potential for future growth in the program. PSE&G has not made any efforts to promote the economic program. PSE&G should prepare an assessment of PJM economic program potential and develop strategies for promoting optimum participation levels. (14-17 to 14-21)

The New Jersey Office of Clean Energy (OCE) has primary responsibility for implementing energy efficiency programs in New Jersey. The BPU sets the policies, goals and budgets for the programs. (14-21)

PSE&G implemented several temporary energy efficiency programs in 2008 and 2009. The programs include both electric and gas energy efficiency and focus on low-income enterprise zones and specific industries. PSE&G's programs are designed to complement the OCE's programs. The low income and industry "carve-out" avoids duplication of OCE programs. The PSE&G programs have a 2011 budget of $58 million. (14-28)

The combined OCE and PSE&G 2011 budget for electric energy efficiency in PSE&G's service territory is approximately $158 million. The 2011 electric energy efficiency budget equals $73 per customer. Electric energy efficiency funding is relatively modest compared to PSE&G's power supply costs. PSE&G spends approximately $3.0 billion a year on BGS-FP power purchases. (14-28)

According to PSE&G: (1) aggressive deployment of cost-effective energy efficiency needs to be a key element of New Jersey's Energy Master Plan; and (2) New Jersey residents and businesses are not investing in efficiency at nearly the rate necessary to meet the state's goals. (14-28)

Energy efficiency measures are a cost-effective way to reduce power supply costs. PSE&G's power supply costs are among the highest in the nation. High power supply costs justify a strong focus on energy efficiency. PSE&G should work to fully integrate energy efficiency into its power supply planning process. (14-29)

Energy efficiency programs can bid as capacity resources in PJM's RPM auctions. The resources must comply with PJM measurement and verification requirements. PSE&G's existing programs do not comply with those requirements and are not eligible to participate in the RPM. PSE&G has not assessed the costs and benefits of designing future programs to comply with RPM requirements. PSE&G should investigate the feasibility, costs and benefits of bidding future energy efficiency programs into the RPM. (14-29 to 14-32)

PSE&G supports renewable energy development. Solar generation is the most viable renewable energy development opportunity in PSE&G's service territory. PSE&G has two programs for promoting solar generation.

- Solar Loan Program - financing for 81 MW of customer-owned solar capacity.
- Solar 4 All (S4A) Program - installation of 80 MW of utility-owned solar capacity.

PSE&G's investment in the Solar Loan Program will be approximately $240 million once the programs are fully subscribed and the projects are in-service. The loans cover approximately fifty percent of the installation costs. In addition to the loans, customers are eligible for federal tax credits.

The S4A approved budget is $515 million. The S4A program consists of two 40 MW segments: (1) centralized solar installations; and (2) utility pole-top installations. The utility pole-top segments consist of 200,000 distributed solar systems mounted on utility and street light poles. The pole-top installation is the largest in the world. (14-38 to 14-41)

PSE&G is currently selling the pole-top solar output in the PJM energy and capacity markets. Treating the output as a reduction in BGS-FP load may be a better alternative. PSE&G should investigate the advantages and disadvantages of treating the pole-top units as BGS-FP load reducers. (14-42 to 14-44)

Non-Utility Generation Contracts (Chapter 15)

PSE&G purchases power under seven non-utility generation (NUG) contracts. PSE&G paid $375 million for power under its NUG contracts in 2009. The three largest contracts are non-unit specific. The other four contracts are much smaller.

The NUG contracts were entered into prior to electric industry restructuring pursuant to the federal Public Utility Regulatory Policies Act of 1978 (PURPA). PURPA required utilities to buy power from non-utility cogeneration and small renewable energy plants at prices equal to the utility's avoided costs. PSE&G's NUG contracts were approved by the BPU over an eight-year period beginning in August 1984 and ending in June 1992. The contract prices were based on projections of avoided costs that soon proved to be unrealistically high. As a result, prices under the NUG contracts are well above market prices.

PSE&G sells the power received under the NUG contracts to PJM. The excess of the NUG contract costs over the resale revenues is recovered from ratepayers through the BPU approved Non-Utility

Generation Charge (NGC). In 2009, the NUG contract costs exceeded resale revenues by $194 million. (15-2 to 15-3)

The three largest contracts accounted for 93 percent of PSE&G's NUG costs and 96 percent of its above-market NUG costs in 2009. Those contracts were originally contracts for the output of cogeneration units located in PSE&G's service territory. PSE&G restructured the contracts in 2000 and 2001. The restructurings provided operating flexibility to the sellers in exchange for price reductions and lump-sum payments to PSE&G.

The restructuring converted the three large contracts into non-unit specific contracts for the financial settlement of energy and capacity obligations. PSE&G does not physically receive any energy or capacity under the restructured contracts. The restructured contracts provide the seller with significant energy scheduling flexibility. That flexibility reduces the revenues that PSE&G receives from the financial settlement of the energy. The restructurings also significantly reduced the capacity revenues received by PSE&G. The resale revenues obtained by PSE&G are consistent with the restructured contract terms. (15-3 to 15-7)

The opportunities for mitigating PSE&G's above-market NUG costs are limited. The three large contracts expire in 2013 and 2014. Those contracts do not result in the delivery of power. Because the seller does not actually deliver power, operational factors do not provide a basis for changing the contract terms. PSE&G does not anticipate any significant future mitigation efforts. (15-14 to 15-15)

PSE&G's management of its NUG mitigation function was adequate in 2007, 2008 and 2009, with one exception. PSE&G engaged in negotiations on two significant issues with the sellers under the three large contracts in 2008. Both negotiating teams included ER&T's senior commercial attorney. ER&T has extensive commercial relationships with the sellers.

Including ER&T's senior commercial attorney on the negotiating teams created the risk that PSE&G's interests would be consciously or unconsciously compromised to preserve ER&T's business relationships with the sellers. The senior ER&T commercial attorney should not have been included on the negotiating teams. (15-16 to 15-18)

Power Supply and Transmission Affiliate Issues (Chapter 16)

PS Power owns 11,807 MW of generating capacity in PJM. Nuclear plants account for approximately 60 percent of PS Power's PJM generation. PS Power is highly profitable. During the most recent four-year period, PS Power's return on equity averaged 27 percent. (16-5, 16-11)

PS Power's competitive advantages include having a low-cost generation fleet with many units located near large load centers east of PJM transmission constraints. According to PS Power, its balanced generation portfolio is in an ideal position to serve BGS load. PS Power provides 36 percent of New Jersey's BGS-FP power supply. PS Power provided 43 percent of PSE&G's BGS-FP power in 2009. (16-12 to 16-13)

Market power is a serious concern in PJM and northern New Jersey. PJM's market power mitigation rules are critical to protecting consumers from market power abuses. (16-15)

PS Power owns 33 percent of all of the generating capacity in PJM's Eastern Mid-Atlantic region and 90 percent of the generating capacity in PSE&G's transmission zone. The number of BGS-FP tranches awarded to PS Power is consistently close to the overall state and PSE&G load caps established by the BPU. That implies that PS Power has a significant cost advantage compared to other bidders. PS Power's high profit levels and the magnitude and persistence of its BGS market share raise concerns about the competitiveness of BGS power procurement. (16-13 to 16-15)

The joint ownership of a regulated utility and non-regulated affiliates creates an incentive to subordinate the economic interests of the utility to those of the non-regulated affiliates. The reality of the incentive, the subtlety with which it can work, and the clear conscience with which a manager can often respond to it all argue for regulatory oversight of affiliate relations. Regulatory oversight is a necessary substitute for the incentives normally created by an arms-length relationship. (16-26 to 16-28)

According to PSE&G, the BPU's Affiliate Relations Rules do not apply to PS Power because it does not offer competitive services to retail customers in New Jersey. The FERC's Affiliate Restrictions require PS Power employees to operate separately from utility employees to the maximum extent practical. The FERC Affiliate Restrictions only apply to utilities with captive customers. According to PSE&G, the FERC Affiliate Restrictions do not apply because PSE&G does not have any captive retail or wholesale customers. (16-28)

Functional separation is a key affiliate relations safeguard. PSE&G does not have any written plans or procedures for ensuring the operational separation of most PSE&G and PS Power employees. PSE&G should develop compliance plans for ensuring that utility and PS Power employees operate independently to the maximum extent practical. PSE&G should also develop a compliance plan to limit PS Power's access to non-public utility information. (16-35 to 16-37)

PS Power provides BGSS gas supply services to PSE&G under a full requirements contract. The contract was implemented in 2002 and is currently scheduled to expire in March 2012.

PS Power has a large portfolio of pipeline transportation and storage contracts. PS Power uses those contracts to provide gas supply for its generating plants and PSE&G's BGSS customers. PS Power allocates the costs of those contracts between BGSS and generation gas supply. (16-43 to 16-46)

The FERC Affiliate Restrictions prohibit utilities from sharing fuel procurement employees with merchant generation affiliates. FERC prohibited the sharing of fuel procurement employees because they would have an incentive to allocate lower-priced fuels to the merchant affiliate. The joint management of BGSS and PS Power generation gas supply creates the risk that BGSS ratepayers will be required to subsidize PS Power's fuel costs. The current arrangement also has adverse market power implications. (16-32 to 16-33)

PSE&G has not reviewed the costs and benefits of outsourcing BGSS gas procurement to PS Power since the initial proceeding in 2002. It is time for a substantive review. PSE&G should prepare a study of the advantages and disadvantages of the current approach compared to the alternatives of: (1) performing the gas supply function internally; and (2) purchasing the services from a non-affiliated vendor. (16-45 to 16-46)

PJM market rules have a significant impact on PSE&G's power supply costs. PSEG directs and controls the management of its subsidiaries, including PSE&G. PSEG's policy is to take one unified corporate position on issues before FERC and PJM. PSEG has a profit motive to adopt unified corporate positions that favor merchant generation interests.

PSEG tends to caucus with generation interests at PJM and FERC. PSEG usually votes for the positions favored by the majority of generation owners at PJM Members Committee meetings. PSEG's positions at FERC frequently coincide with those taken by generation interests.

PSE&G advocates the PSEG unified corporate position. The alignment of PSE&G and generation owner positions raises concerns that PSE&G's positions are being shaped to advance the interests of its merchant generation affiliates. (16-48 to 16-51)

The process of developing the unified PSEG corporate positions includes extensive commingling of utility and merchant generation interests and views. PSE&G defers to PS Power's market expertise on PJM issues because of its superior knowledge of the issues. Relying on PS Power for expertise on market issues provides it with an opportunity to advance merchant interests. (16-51 to 16-53)

PSEG balances the interests of the utility's distribution customers and PS Power when developing the unified corporate positions. That balancing process is completely undocumented. The lack of contemporaneous documentation impedes regulatory oversight. (16-55)

The joint development and mandatory advocacy of unified corporate positions creates risks for utility customers without any offsetting benefits. The utility should independently develop and advocate positions at PJM and FERC that advance the interests of its distribution customers, while preserving the utility's financial position. (16-56)

Interconnection and Non-Power Services (Chapter 17)

FERC and PJM control the interconnection process for new generation. That protects consumers against anti-competitive behavior in the interconnection process. The interconnection process has not been a problem in PSEG's zone. Very few large generating stations have been proposed for PSE&G's zone. (17-5 to 17-8)

PSE&G does not oppose or support merchant transmission projects that export power to New York City. According to PSE&G, it does not have the capability to discourage the development of merchant transmission projects. (17-8 to 17-11)

PSE&G prepared a transmission impact study for PS Power in 2009 outside of the PJM interconnection process. The study identified network upgrades required for adding a new nuclear unit adjacent to Hope Creek and Salem on Artificial Island. The study utilized ratepayer-funded expertise and resources. The transmission impact study provided an opportunity to coordinate PSE&G's PJM transmission planning positions with PS Power's interests.

PJM only prepares transmission impact studies after the receipt of a valid interconnection application. The interconnection request establishes the developer's position in the interconnection queue which impacts the developer's responsibility for system upgrade costs. PJM publishes the transmission impact studies it prepares on its website. Providing unpublished transmission impact studies to merchant generation affiliates without an interconnection application may provide an unfair competitive advantage to the affiliate.

PSE&G charged a lump-sum fee of $105,000 for the transmission impact study. PSE&G did not track the actual costs of preparing the study. Regulatory oversight of affiliate charges is difficult when the costs of providing services are not tracked. PSE&G should track the labor hours and costs of providing services to PS Power. (17-11 to 17-15)

PSE&G standardized its interconnection agreements with PS Power in 2010. The new agreements will improve PSE&G's internal controls over interconnection service billings. PSE&G's charges to PS Power for interconnection attachment facility maintenance appear to be reasonable with limited exceptions. PSE&G did not charge PS Power for meter inspection and testing services prior to 2011. PSE&G will charge approximately $200,000 a year for those services under the new interconnection agreements. PSE&G should require PS Power to pay the metering costs it did not bill during the period 2000 through 2009. (17-15 to 17-19)

The station power values PSE&G reported for PS Power's Essex, Bergen and Linden plants were below industry benchmarks in 2009. PSE&G should explain the reasons for those low values in its response to this report. PSE&G should improve its internal controls over the measurement of net generation at PS Power generation plants.

PSE&G uses local distribution facilities to deliver station power to PS Power generating plants. PSE&G provides most of those services at a steep discount from tariff rates. The discounts totaled approximately $4.3 million in 2009.

PSE&G should charge tariff rates for the station power delivered to PS Power over local distribution facilities. If PSE&G believes discounts are justified by a legitimate by-pass threat, it should provide estimates of PS Power's by-pass costs and explain its discounting strategy. (17-19 to 17-29)

PSE&G and PS Power provide large amounts of non-power goods and services to each other. PSE&G charged $7 million to PS Power for equipment maintenance and construction in 2009. From an internal control perspective, PSE&G treats the work it performs for PS Power the same as utility work. PSE&G's management reports and internal reviews are inadequate. PSE&G should improve its internal controls over charges to PS Power. (17-30)

PS Power billed approximately $16 million of non-power goods and services to PSE&G in 2009. Most of the services were provided by PS Power's Maplewood Testing Services (MTS), System Maintenance Division and Central Maintenance Shop. MTS provides specialized testing services covering all of the equipment in PSE&G's distribution and transmission system. MTS is PSE&G's sole source for those services. The 2010 budget for MTS charges to PSE&G was $7.0 million. (17-41 to 17-43)

The BPU's Holding Company Rules prohibit PSE&G from purchasing any services from affiliates that PSE&G can obtain "on more advantageous terms" by other means. The rules require PSE&G to review its purchases from affiliates every three years for compliance with the most advantageous terms requirement. The initial review is required by April 2012. PSE&G should review its purchases from PS Power for compliance with that requirement. (17-45)

PSE&G's internal controls over charges from PS Power are inadequate. From an internal control perspective PSE&G treats the charges from PS Power the same as internal utility charges. PSE&G does not implement any controls beyond those that apply to work it performs internally. PSE&G's management reports for charges from PS Power are inadequate. PSE&G should improve its internal controls over charges to and from PS Power and also enter into a Services Agreement with PS Power. (17-46 to 17-49)

Gas Procurement and Supply (Chapter 18)

This assessment focuses on PSE&G's management of gas procurement and supply activities for the distribution of gas to customers. The central components of gas procurement and supply examined included the demand forecast, cost of gas, and the delivery of sufficient gas supply at PSE&G's city gate stations to meet customer demand. The subject of gas price hedging strategies is addressed in the 2009 BPU study entitled Analysis of the Gas Purchasing Practices and Hedging Strategies of the New Jersey Major Gas Distribution Companies, which evaluated New Jersey gas utilities' natural gas hedging activities between 2001 and 2007. (18-1)

PSE&G is responsible for preparing a forward-looking annual demand forecast. PSE&G uses a modified Heating Degree Day Index, which should better reflect the effect of weather on sales demand during the shoulder months. Shoulder months are the critical months where large day-to-day demand swings are more likely, and gas from storage may not be available. The current monthly demand forecast model methodology shows very good correlation to actual monthly billing data, but communicates no information about forecast uncertainty. Additional insight into the underlying assumptions in monthly demand and peak-day demand can be gained through Monte-Carlo Simulation. Furthermore, since the peak-day forecast is affected by the customer class mix, the forecast model should be recalibrated. PSEG Energy Resources and Trade (ER&T) is obligated to meet the peak-day and seasonal needs of the firm customers of PSE&G as forecasted by PSE&G. (18-8 to 18-10)

PSE&G is well positioned to administer gas procurement and supply, but not manage this function. The gas procurement and supply function, and in effect its management, is outsourced to PSEG ER&T. PSEG ER&T is responsible for securing capacity at the most reasonable rate, while considering reliability and the location of the receipt and delivery points. PSEG ER&T has a high level of skills and capabilities and sophisticated tools and methodologies to manage gas procurement and supply program. The relationship between PSE&G and PSEG ER&T is one of codependent, rather than independent.

PSE&G does not measure month-to-month volatility. PSE&G reports the weighted average inventory method of accounting for gas purchases, which eliminates any significant volatility for its residential gas supply portfolio. Use of an accounting method that dampens the volatility is no reason not to monitor the actual price volatility. (18-11)

In Docket Number GM00080S64, dated April 7, 2002, the New Jersey Board Public Utilities ordered PSE&G to transfer all gas commodity and capacity agreements and related instruments to its unregulated affiliate PSEG ER&T. The Gas Requirements Contract provides for PSEG ER&T to negotiate contracts that, in its good faith judgment, are necessary and useful for fulfilling its obligations under the Contract, without notice, review, or approval of PSE&G and for which PSE&G could be obligated when the Gas Requirements Contract is terminated. Furthermore, PSE&G lacks adequate measures to assess effectively PSEG ER&T's performance with regard to the Gas Requirements Contract, Gas Supply, Storage and Transportation Procurement, and Price Hedging Strategy. (18-3, 18-24 to 18-27)

PSE&G has a solid internal auditing program. The annual audits of PSEG ER&T's adherence to policies, procedures, contacts, and transactions assure a high level of compliance. As long as PSEG ER&T has a plausible basis for its allocations, PSE&G internal audit can be expected to accept the allocation, even if better methods are available. PSEG internal audit cannot be expected to aggressively challenge questionable cost allocations between PSEG Power and BGSS. Regulatory oversight is needed to protect BGSS customers. (18-27)

Key Recommendations:

- PSE&G should employ Monte-Carlo Simulation or similar techniques to better communicate the gas demand drivers and forecast uncertainty. Likewise, PSEG ER&T should employ similar techniques to better communicate to PSE&G the forecast price and cost of gas to PSE&G delivery points.

- PSE&G should establish written performance expectations of ER&T that address transparency, accountability, and accuracy. Such performance measure considerations include (1) price volatility; (2) potential cost and out-of-market outcomes tolerance; (3) utilization of firm capacity; and (4) capacity release target.

- PSE&G should re-assess the value of its Gas Requirements Contract by either (1) issuing a competitive bid request for proposals to pre-qualified bidders, or (2) preparing a study and cost/benefit analysis of terminating the ER&T contract and submitting the study in its next BGSS proceeding.

- PSE&G should amend the Gas Requirements Contract to provide for (1) advance written notification of any negotiations which could pose an obligation to PSE&G when the Gas Requirements Contract is terminated; and (2) written support demonstrating the need, cost, and benefits of all negotiated contracts which pose an obligation to PSE&G when the Gas Requirements Contract is terminated.

- The Gas Requirements Contract should be modified to address (1) audits performed on behalf of the NJBPU; (2) provision for intra-day nominations; (3) approval of changes in Storage and Transpiration contract quantities; and (4) approval of firm gas supply contracts of longer than one year.

Distribution Operations and Maintenance - Electric (Chapter 19)

PSE&G has well-structured operations, maintenance programs, and systems in place to track its performance. O&M spending level per customer has tracked first quartile utilities and is below the median level. Vegetation management programs appear to be effective as tree-related outages have steadily decreased over the 2005 to 2009 period. PSE&G should continue its proactive focus on reliability-centered maintenance. (19-4 to 19-8)

PSE&G's Energy Utility Technology Degree Program, established in 2003 has been very successful at attracting new technical hires (68 through mid-year 2009) and is endorsed by three participating unions. Overtime statistics are averaging between 26% and 27%, with peaks as high as 30% among certain groups. This is in line with recent findings of other large utilities, but in our opinion is endemic of the technical workforce shortfall affecting utilities across the country. In our opinion, these levels are excessive. PSE&G should consider actions to reduce the average level of overtime, particularly for field workers, without sacrificing reliability, and should continue and consider expanding its Utility Technology Degree Program to attract additional potential technical resources on a fast-track basis to mitigate expected attrition through retirements. (19-10)

PSE&G appears to realistically design, plan and execute its work. Over the past two years, the variance between planned and executed work orders has been approximately 99%, and PSE&G performs maintenance and inspections in conformance with industry best practices and in some areas exceeds industry averages. Its inspection backlog is virtually zero. (19-11 to 19-12)

PSE&G is highly focused on system reliability performance, and pays constant attention to the reliability performance of the system. PSE&G has consistently maintained top of class reliability performance and was recognized by the PA Consulting Group as the winner of its National Reliability Excellence Award for its reliability performance in the years 2004, 2005, 2007, and 2008. PSE&G was also recognized by the PA Consulting Group as its Regional winner in the Mid-Atlantic Region for the utility's reliability performance in the years 2004, 2005, 2006, 2007, and 2008.

PSE&G conducts its own peer survey for reliability and participates in the I.E.E.E. annual national reliability survey and consistently ranks in first quartile both for CAIDI and SAIFI. (19-18 to 19-26)

PSE&G has a well-conceived and applied emergency response capability which includes industry best practices; for example, PSE&G employs outside assistance from mutual assistance crews as needed, but only had to call on these resources twice in the past six years; and the Emergency Response Plan contains provision for developing, recording, and acting on lessons learned following major events through a formal process. (19-26 to 19-28)

PSE&G employs state-of-the-art techniques in the load forecasting process and adheres to the Company's internal Design Standards which, in turn, conform with the Industry Standard Specifications, and PSE&G closely coordinates with PJM for transmission planning and operations. (19-29 to 19-30)

PSE&G has an annual, multi-step, and multi-level corporate budgeting process, where the budgets undergo several levels of review before they are finalized. Close attention is given to the possible impact on reliability due to budget changes. Corporate and division management monitor budgets and reliability from a corporate score card perspective and will make adjustments as necessary to meet the KPIs. There were no T&D capital budget reductions over the 2005 to 2008 period; however, there were small reductions in O&M budgets over the same period averaging 2.3% annually, mainly reflecting modified scope. PSE&G's capital expenditures per customer have increased slightly over the 2004 to 2008 period. PSE&G has a robust project estimation protocol to ensure realistic estimates at each stage of project development. Further, the Company measures project success on the basis of schedule, scope, and budget; these metrics are part of the key performance indicators. (19-33 to 19-39)

PSE&G does well in ensuring NERC compliance via self-assessments and mock audits, but the Company fears that NERC ruling changes will lead costs to exceed benefits. PSE&G would like to see NERC standards be more results or performance based. The utility should engage PJM and work toward achieving NERC standards being based on results and performance. (19-45 to 19-46)

PSE&G's philosophy of Smart Grid is focused on reliability and is an important factor contributing to its reliability leadership. The Company has taken an aggressive lead in smart grid initiatives which can also provide benefits in the areas of safety, operations, and renewables for the customer. (19-46 to 19-49)

PSE&G is among the most advanced users of dedicated IT systems among large electric utilities, and the Company has made significant improvements over the past ten years, and most systems are integrated to promote efficiency and accuracy.

Key Recommendations:

- PSE&G should continue and consider expanding its Utility Technology Degree Program to attract additional potential technical resources on a fast-track basis to mitigate expected attrition through retirements.
- PSE&G should consider actions to reduce the average level of overtime, particularly for field workers, without sacrificing reliability
- PSE&G should engage PJM and work toward achieving NERC standards being based on results and performance.
- PSE&G should engage the BPU to better define its role in demand side management.

Distribution and Operations Management – Gas (Chapter 20)

PSE&G's gas distribution system is older than most of the distribution systems in the rest of the country. Almost half of its mains and services were installed prior to the Federal Pipeline Safety Regulations enacted in 1970. In addition there is no other US utility with more cast iron/ductile iron in its gas distribution system than PSE&G, with 4,342 miles or almost 25% of its system being cast iron. The Company does not have defined goals for achieving total replacement of its cast-iron mains. Based on the present rate of replacement, PSE&G expects some of its cast iron to last as long as 195 years from the original date of installation. (20-4 to 20-18)

The key to distribution system integrity for PSE&G is a strong focus on inspecting, maintaining, and replacing the cast iron and bare steel systems; and the Company does conduct a number of maintenance/inspection activities or practices to help ensure the reliability and safety of its system which exceed regulatory requirements. Leakage rates compare favorably to the companies with relatively similar main systems, but PSE&G main leakage rates are nearly twice the national average when compared to utilities with newer distribution systems. Cast iron is being replaced at a rate that will allow the annual break/mile rate to stay close to first quartile performance when compared to a very limited benchmark panel. (20-19 to 20-34)

PSE&G has an annual, multi-step and multi-level corporate budgeting process, where the budgets undergo several levels of review before they are finalized. During the process close attention is given to the possible impact on reliability due to budget changes. Corporate and division management monitor budgets and reliability from a Corporate scorecard perspective and will make adjustments as necessary to meet established KPIs. (20-34 to 20-42)

System designs are performed with a focus on reliability and in adherence with federal and state codes. Quality assurance or verification of design standards and codes for gas projects includes: use of the Gas Delivery Design Manual by design engineers, use of the Gas Delivery Gas Distribution Standards Manual by field personnel, Operator Qualifications or OQ Plan certification and frequent field interaction. (20-42 to 20-47)

Gas procurement and supply is managed by PSE&G, the regulated utility. However, PSEG Energy Resource and Trade, a non-regulated entity reporting to Public Service Enterprise Group, performs the actual gas supply procurement. Load forecasting reports with various time horizons are prepared by the Electric and Gas Sales and Forecasting group and the Asset Management group within PSE&G's Gas Delivery. Respective reports are complementary to the gas procurement and system design effort. (20-47 to 20-48)

Key Recommendations:

- Conduct an in-depth study to explore the benefits of accelerating its cast-iron replacement program. The study should be accompanied with an assessment of possible regulatory cost recovery mechanisms. The finalized study along with its underlying assumptions should be formally presented and discussed with the New Jersey Board of Public Utilities.
- Expand the makeup of the Peer Panel Benchmarking companies to include those with greater amounts of cast iron remaining in their system. This would permit a more balanced assessment of performance in this critical area.
- Develop a program that prioritizes the replacement of all short sections of cast-iron pipe operating above utilization pressure. The program should have a definitive start and end date consistent with prudent distribution system risk management.

Contractor Performance (Chapter 21)

In our evaluation, we reviewed the excavation damage program, field audits conducted at contractor facilities, accuracy of mark outs, management of outside contractors, project management approach, contractor performance, and contractor inspection procedures. Both Gas Delivery and Electric Delivery maintain a trained and experienced internal workforce with skills necessary to perform required work activities. PSE&G utilizes its internal workforce for most electric and gas distribution activities. Much of the work contracted represents work required at peak periods, or on large or specialized projects. (21-1 to 21-2)

All damage prevention locates are performed by PSE&G employees, resulting in the Company taking "site ownership" and achieving significant reductions in third-party damages. Quality is assured through field audits that are completed quarterly for all locators normally assigned to perform locates; the audit process includes verification of the marks and accuracy of the documentation; results are documented and shared as lessons learned. This program has been increasingly effective since from 2004 through 2009, Gas and Electric Delivery has reduced the total number of damages to its distribution system by 44%. (21-2 to 21-6)

In 2008 PSE&G formed the Delivery Projects and Construction (DP&C) organization. Included within this group is a project management/control structure, a mobile construction workforce, a work integration group and safety oversight. This organization is currently evolving through a multi-year implementation plan. In the first quarter of 2009, workflows were put together for cost control, scheduling, scope management, and estimating with the expectation of enhanced project execution. The processes that were developed to support a more detailed project management approach are embodied in a document entitled Project Construction Oversight dated June 9, 2009. Later in 2009, the Company introduced an enhanced vendor invoice management process and initiated design requirements for Primavera P6 software. Full implementation of the Electric Delivery Project Portfolio was scheduled for the end of 2010. (21-7 to 21-10)

In connection with outsourced construction activity, PSE&G ensures and monitors the quality of its contractors' performance using a thorough Project Construction Oversight and field monitoring processes for larger projects. Procedures are in place to ensure system safety is ultimately PSE&G's responsibility, regardless of whether a contractor performs the work or not. (21-10 to 21-12)

Projects that are generally more standard and smaller projects are routinely initiated and managed within Gas Delivery or Electric Delivery, while larger more complex and specialized projects are managed by Delivery Projects and Construction. These larger projects are subjected to a four-stage risk analysis and contingency assignment to develop costs. These include: Office Level Estimate (less than a 50% confidence level), Study Level Estimate (50% confidence level), Conceptual Level Estimate (70% confidence level), and the Definitive Level Estimate (90% confidence level). (21-12 to 21-14)

Customer Service and Meter Reading (Chapter 22)

PSE&G's Customer Operations organization is housed within PSE&G unlike many other back-office administrative functions. A primary focus of this group in recent years has been the replacement of the company's 28-year old customer information system. The new customer information system along with a number of other customer service system upgrades and enhancements were globally referred to as "iPower". (22-3 to 22-6)

The roll-out of iPower was met with mixed reaction. On the one hand, the iPower implementation won industry awards and peer company accolades, and management was successful in bringing the project in under budget. On the other hand, expectations of many different constituents (such as customers, the BPU Staff, company management, and the PSEG Board of Directors) were not met. During the transition to the new system, customer service performance metrics as measured by a balanced scorecard temporarily "dipped". (22-6 to 22-13)

As benchmarked against other utilities, PSE&G's customer service functions were average at best during the period we reviewed. This was most likely due to the "dip" in statistics associated with the system conversion, unfavorable cost comparisons that result from operating in a service territory with a high cost of living, and a relative lack of automation in terms of advanced metering infrastructure. (22-13 to 22-21)

Customer satisfaction, especially among small business customers, was below average in nearly half of the categories measured in the third quarter of 2009. PSE&G has assigned the task of improving customer satisfaction to Perception Working Teams. (22-22 to 22-24)

In 2009 and 2010, the company experienced problems with customer-submitted meter read data. The company asserted that a system defect that was responsible for these problems had been corrected in November 2010. However, we did not independently verify this assertion. (22-25 to 22-26)

The company operates call centers from three different locations in New Jersey, two of which handle emergency calls. In order to minimize customer wait times, PSE&G increased the number of personnel assigned to call centers between 2007 and 2010. The company also focused on improving the customer service experience of callers who do not speak English as a first language. (22-27 to 22-29)

As part of the iPower roll-out, web self-service was introduced. The company expects that the usage of this tool to increase dramatically in the near term. (22-29)

Key Recommendations:

- Take the necessary steps to improve customer satisfaction so that it meets or exceeds levels measured prior to the iPower project implementation. Over time, this will allow the company to achieve top quartile ratings, which is the goal for most operating statistics.
- Either subject customer-submitted meter reads using the interactive voice response unit to immediate validation, or inform the customer that his/her reading is subject to final validation. This would eliminate situations in which a customer-submitted reading is rejected without the customer being made aware of the situation.
- The company should consider limiting the number of balanced scorecard metrics tracked for major functional areas (e.g. Finance, Customer Operations, etc.) to those most critical to the assessment of the entire organization.

Salary, Wage and Compensation, and Benefits (Chapter 23)

PSEG's compensation philosophy is designed to foster a "Total Rewards Mentality". It consists of both regular compensation and incentive payments. For middle and upper level positions, the company uses national level data for comparison purposes and regional and local area data is used for lower level positions. PSE&G targets the 50th percentile of the peer group of energy services companies for compensation levels and managing pay delivery. PSEG uses lump sum payments, promotions, cash bonuses and equity adjustments to differentiate employee compensation. (23-6 to 23-12)

PSEG indicates it has designed an Executive Compensation Program (Program) to attract, motivate and retain high-performing executives who are critical to its long-term success. Compensation for executives is based on the median compensation of similar positions in PSEG's peer group of energy companies, adjusted for performance and experience, business factors, and relative pay positioning among executives. This methodology is reviewed at least annually by the Organization and Compensation Committee of the Board of Directors with the help of independent outside consultants. (23-3 to 23-6)

The system utilized to perform Non-Represented Employee Performance Evaluations, Empower, is very effective. Some of the advantages of Empower have been: a stronger link between individual performance and PSEG business goals and initiatives, enhanced communication between managers and employees, improved managerial planning and coordination, shift of focus from a single event to an ongoing process that supports the company's culture and enhances results, and balanced results with desired behaviors and continued growth and development of employees. (23-12 to 23-19)

Three separate incentive programs cover non-union, non-executive staff, executive staff, and the most senior executive staff. PSEG's Senior Management Incentive Compensation Program is designed to foster the attainment of financial and operating objectives among executives and other important positions. The Performance Incentive Plan for Certain Employees is designed to foster financial and operating objectives among employees. PSEG's Management Incentive Compensation Plan is designed for key officers and executive level employees. (23-15 to 23-36)

PSEG has a large number and wide variety of benefit programs. However, despite the number of plans and the benefits provided, PSEG compares favorably with its Peers regarding the cost of its benefits programs. (23-36 to 23-40)

Key Recommendations:

- While the performance evaluation processes for Represented Employees are strong, there is a need for clarification and simplification of the forms related to the electrical and gas delivery evaluations.
- Position descriptions should be expanded and provided for all positions.
- The large number and wide variety of PSEG benefits programs are difficult to follow and presumably to administer. The company could benefit from a summary document of these various programs by type, eligible employee, and benefits provided.
- PSE&G should develop an organizational manual and reconsider some spans of control.

Productivity and Utilization Level of the Workforce (Chapter 24)

PSE&G utilizes several mechanisms to manage employee productivity. Our review of the elements of the productivity management system included sample Balance Scorecards, Operational Excellence Models and Work Management Systems. We found them to be in place and effective. (24-1 to 24-3)

The Workforce Planning Process is well-defined and effective. The main drivers of this process are: translate strategy into talent implications, diagnose strategic talent gap, select talent management strategies, and implement and measure. Each year during the business planning process, each PSEG company reviews its current staffing levels for both non-union and union employees and determines if these levels are sufficient to meet their specific business operating needs. It appears that spans of control can be improved by decreasing some, but mostly, by increasing many. (24-6 to 24-11)

Development, Training, Evaluation, and HR Ability to Access Personnel Information and Perform Assigned Duties (Chapter 25)

PSEG has a very structured process for recruiting and hiring its employees. The process is well documented in its HR Practices manual. The Company believes that its practices ensure that it selects the best candidate for a job, through fair and consistent processes. The average number of days to accept a position is 45 days. In comparison to its peers, this is better than the median and close to the top quartile. (25-1 to 25-2)

PSE&G has effective training, development, and evaluation techniques. Training is delivered through various means, traditional instructor/student, face to face in the classroom, using a staff of subject matter experts, full time instructors, operational line of business experts acting as instructor adjuncts; contract adjuncts and out-sourced training. Alternative computer based training supplements the classroom instruction. The Company annually provides mandatory online Affiliate Compliance training to all MAST employees and in-person training to all represented employees. The Performance & Development Group of Human Resources tracks the training and maintains participant lists and any cost data. (25-3 to 25-12)

Access to Personnel information is adequate through the use of SAP and Empower. Human Resources utilizes SAP as the official system of record for employee information. (25-12 to 25-15)

Key Recommendation:

- PSEG should develop an organizational manual and develop position descriptions for all significant positions.
- PSEG should also make greater use of technology in its recruitment efforts.
- In order to expand it recruitment efforts, PSEG should continue and increase its outreach to students.
- PSE&G should consider establishing mentorship programs for high potential employees that managers consider to be appropriate candidates for promotion within the Company.

Labor Relations, Affirmative Action, and Equal Employment Opportunity (Chapter 26)

PSE&G has open communications with its unions. There are over 6,300 union employees at PSE&G. There are six unions, four of which are in New Jersey, one in Albany, New York and one in Connecticut. (26-1)

PSE&G provides adequate labor relations training to its managers and supervisors. The Company's Supervisory Academy provides training to all first line supervisors who will supervise union employees on the terms and conditions of the collective bargaining agreements, positive discipline, performance management and managing availability. The Company also provides training to its union employees. This training includes safety training, driver training, diversity training, and sexual harassment training, among others. The Company should enhance its labor relations training by keeping executive level management, as well as, supervisory line management aware of National Labor Relations Board case developments as well as federal court decisions that may impact the scope and application of such matters. (26-2)

PSE&G has good constructive relationships with its unions. PSE&G's labor relations philosophy is to work in an environment of mutual respect and trust. PSE&G has a very structured dispute resolution process. The number of grievances filed by PSEG's bargaining unit employees is lower than the top quartile for the Industrial Relations Benchmark. (26-3 to 26-4)

PSEG Equal Employment Opportunity (EEO) and Affirmative Action (AA) programs have been widely recognized to be successful and effective. PSEG has an Affirmative Action Compliance Manager at each of its locations. There are 75 Affirmative Action plans; at least one for each location. PSEG has three specific AA programs. There are AA programs for women and minorities, AA plans for disabled employees, and AA programs for veterans. PSEG also maintains a Diversity and Inclusion Policy as well as a number of Diversity Outreach Partnerships. The Company should increase the amount and frequency of diversity training that it provides to its bargaining unit employees in order to enhance a culture of inclusion. (26-4 to 26-9)

Remediation Costs (Chapter 27)

The BPU periodically reviews the costs associated with remediating former PSE&G manufactured gas plant sites. In the most recent reviews, no adverse findings or recommendations were noted. However, the company has agreed to file additional information to aid the Staff in carrying out these reviews. (27-2 to 27-4)

Internal Audit identified three areas of concern in 2007 when it reviewed remediation cost activity. BPU Staff has expressed its satisfaction with management's response to the recommended action plans submitted by Internal Audit. (27-4 to 27-5)

Key Recommendation:

- Add the following to the minimum requirements associated with PSE&G's annual remediation adjustment charge filing:
  - The disclosure of all internal control deficiencies, significant deficiencies, or material weaknesses related to Remediation Adjustment Charge expenditures or cost recoveries,
  - The identification of remedial steps taken by management to correct such deficiencies, significant deficiencies, or material weaknesses, and
  - The summarization of additions, deletions, or amendments to the company's Site Remediation Project Directives during the applicable RAC period under review.

Support Services (Chapter 28)

Support services include the following:

- Information Technology (IT)
- Security and Claims
- Law
- Corporate Records Management
- Fleet Management
- Supply Chain

Information Technology (IT) - IT is the most significant support function in PSEG Services Corporation. Approximately 225 IT employees accounted for more than 38 percent of the service company's total incurred cost (excluding convenience payments) during the period 2007 through 2009. Nearly three-fourths of IT's cost was charged to the PSE&G; however, this was skewed to some degree by the iPower project, which comprises a significant percentage of the $111 million in Utility. (28-2 to 28-8)

During the audit period IT maintained an average of approximately two dozen scorecard metrics. For those in 2008 and 2009 for which both target and achieved data were available, IT exceeded its targets for a majority of its metrics. Results are summarized in table 28-4. (28-8 to 28-10)

Key information systems managed by IT during the audit period included:

- SAP Enterprise – The SAP Enterprise group of systems cover accounting and financial reporting, human resources, supply chain management, work management, and environmental, health and safety management.
- iPower – iPower was implemented in 2009 and is PSE&G's new customer information system. It also includes functions that replace older gas services and meter data systems. At the time of our review, a service dispatch module was scheduled to be added in 2012.
- Outage Management (OMS) and Geographic Information (GIS) Systems – OMS manages electric distribution service interruptions. It tracks the location of outages, estimates affected customers, and dispatches outage-related work. It was upgraded in 2007 and hardware upgrades were scheduled for 2011. The GIS supports OMS and provides facilities' locations and maintains customer-to-transformer circuit linkage information.
- Delivery Work Management System (DWMS) – Through connections with mobile data terminals, DWMS plans, assigns and manages most work activities in the field. It was upgraded in 2007, and hardware upgrades were scheduled for 2011.
- Energy Management System and SCADA – The EMS and SCADA systems manage the operation of PSEG's transmission system and coordinate the dispatch of power through the system.

Security and Claims – The responsibilities of Security and Claims include asset protection and preparedness, information and infrastructure assurance, facility relocation, claims processing and investigation and financial recovery. PSEG maintains a Master Security Plan and a Security Council. PSEG also works with the BPU and the New Jersey Office of Homeland Security to develop and implement policies that reflect "best security practices." PSEG participated in the development of a utility sector "best practices" manual following September 11, 2001. A command center was implemented after "9/11" to provide centralized, 24/7 security oversight of all critical facilities and was the first of its kind in the region. Claims and Security underwent an organizational redesign between 2007 and 2009, resulting in a reduction of full-time positions from 50 to 44. During this time overall cost declined by approximately $3 million. As of April 2010, the organization had 41 employees, split approximately evenly between security and claims activities. (28-11 to 28-14)

During the audit period, PSEG maintained approximately 20 security and claims performance metrics. Audit period data shows PSEG exceeded most of its targets for those metrics for which both targets and results were available. (28-15 to 28-16)

Law – During the audit period the Law function was divided into the following eight significant service areas:

- Corporate and Commercial – Negotiating, drafting, executing and interpreting transactions and contracts.

- Energy Trading – Analysis of legal issues for physical and financial energy trading.

- Nuclear – Legal matters associated with PSEG's nuclear business.
- General Litigation – Collection, bankruptcy, and property matters.
- Labor and Employment – Federal and state employment laws, court representation on labor matters and human resources legal guidance.
- Regulatory – State and federal regulatory matters and compliance. Represents PSEG before regulatory agencies.
- General Compliance – Compliance in the areas of ethics, corporate governance and code of conduct.
- Business and Administrative Support – Legal function management and administration.

Overall legal costs remained fairly steady during the audit period, rising from $22.8 million in 2007 to $23.3 million in 2009. During the past decade, PSEG has applied competitive procurement practices to the legal function. Consistent with a competitive rather than a relationship-driven process for acquiring outside legal expertise during the audit period, external legal work was spread out over several dozen different firms, with spending per firm seldom exceeding $1 million in a given year.
PSEG participated in the Hildebrandt Law Department benchmarking survey. In 2008 this survey included 26 participants in the Energy and Utilities subgroup. The most important cost efficiency statistics in this survey are legal spending as a percentage of revenue and spending "per lawyer." In terms of Law Department cost efficiency, PSEG scored well against the benchmarks in the two years we reviewed. (28-16 to 28-22)

Corporate Records Management – This organization, which is managed by the Law department, coordinates records management for the PSEG companies. It maintains a records retention policy and schedule, assists with retention compliance, documents storage and destruction in accordance with policy and manages the storage and destruction process. In 2008 and 2009, the Law department maintained one significant statistic for the function: cost per internal client contact. This was $25.58 in 2008. A scorecard target of $23.00 was set for 2009, and a cost of $21.02, exceeding the target and 18 percent below the cost achieved in 2008, was achieved in 2009. (28-22 to 28-25)

Fleet Management – Responsibilities for this function include acquisition, maintenance, disposal and administration of the transportation fleet. In April 2010, the organization consisted of 213 employees, comprised mainly of mechanics and maintenance shop employees. During the audit period, the Fleet function managed approximately 5,700 units of rolling stock stationed in 23 field locations. Benchmark statistics for 2008 show the fleet was a little older than that of the average utility (6.1 years vs. a utility average of 5.6 years). The average number of units per mechanic was lower than average (37 vehicles vs. a utility benchmark average of 54). The number of rolling units per support employee (110) was also below the utility average (137). PSEG's annual cost per vehicle ($13,639) was significantly below the benchmark average ($18,363), while cost per unit of power equipment was somewhat higher ($11,796) than the average ($9,549). The company cited preventative maintenance, fuel efficiency and price management (hedging), relatively high levels of mechanic experience levels and fleet utilization initiatives as factors contributing to lower vehicle costs. Annual vehicle cost-per-utility customer, which averaged $22.84 for the benchmarked utilities, was not available in the 2008 benchmark survey for PSEG. (28-25 to 28-31)

Supply Chain – As of April 2010, the Supply Chain (Procurement) organization had 96 employees divided among strategic sourcing, supply chain management and governance functions. Overall costs increased from $11.2 million in 2007 to $14.9 million in 2009. PSEG began the balanced scorecard process in 2008 for the Supply Chain Division. For the most part, the 2009 results met the targeted goal for the year. One metric that is noticeably under expectations is the measurement of customer satisfaction. The company measures customer satisfaction through a 13-question survey. A couple of the questions that received the lowest scores in the survey related to how well SCM understood the business requirements of their internal (PSEG) customers and how well SCM did in resolving supplier-related performance and quality concerns. (28-32 to 28-37)

Significant Subsequent Events Occurring in 2011

PSE&G's Contract with the Long Island Power Authority

On December 15, 2011 the Long Island Power Authority (LIPA) announced that it chose PSEG and subcontractor Lockheed Martin Services to operate LIPA's electric transmission and distribution system. LIPA owns the transmission and distribution system on Long Island and provides electric service to more than 1.1 million customers. National Grid, a British company which owns electric and gas utilities throughout New York and New England, currently operates the Long Island electric system on behalf of LIPA under a management services agreement that expires December 31, 2013. PSEG will take over operation of the system in January 2014.

In terms of revenue, LIPA is the second-largest municipal electric utility in the U.S. and will be a significant addition to PSEG's operating and management responsibilities. As such, Overland believes it will be a significant area for analysis in the next PSEG management audit. Among the issues for consideration will be the cost implications of operating the LIPA system, the potential for PSEG to cross-subsidize LIPA activities with revenues from PSE&G and the possible diversion of utility management expertise and attention from PSE&G to LIPA. For example, at least to some extent, LIPA's operations will be incorporated into PSEG's enterprise accounting, human resources, outage management, dispatch and field services management systems and procedures. This could require significant project-level efforts from employees of PSEG Services and possibly PSE&G itself over the next couple of years, which in turn could affect New Jersey electric operations.

As the owner of the Long Island gas utility (formerly Brooklyn Union Gas – Long Island), National Grid is currently able to extract certain economies from overlapping electric and gas service territories. PSEG will not be able to realize economies from territory overlap and could face a somewhat higher cost structure as a result. For instance, National Grid's joint electric and gas meter operation on Long Island will not be possible for PSEG. There may be operating and customer facilities currently used by National Grid to serve both its gas and LIPA's electric operations that can no longer be shared by LIPA and National Grid, resulting in the loss of joint-use economies. Depending on how PSEG chooses to staff the management of the Long Island operation - with or without significant transfers of existing National Grid operations managers and engineering professionals - it could require significant time and effort for PSEG to obtain the institutional knowledge necessary to run the system efficiently.

National Grid currently owns much of the power generation serving Long Island. Although it doesn't necessarily affect PSEG's costs, the change in distribution system management from National Grid to PSEG has the potential to affect the Long Island power supply and the prices LIPA and its customers pay for electric power. The political ramifications of increases in electricity prices coincident with a change in system management could reverberate to PSEG.

Finally, it will be important in the next audit to consider the impact of adding Lockheed Martin as a sub-contractor. National Grid has no equivalent subcontractor or cost under its current agreement. Specifically, the audit should consider the potential impact of an additional layer of administration and whether Lockheed has the utility management expertise necessary to justify the cost it adds to the management services contract.

PSEG Nuclear Proposed Expansion

In May 2010 PSEG Nuclear filed an application for an Early Site Permit with the Nuclear Regulatory Commission for a fourth reactor at Artificial Island in Salem County. The utility identified a site north of the Hope Creek plant as a possible location for the new reactor. The proposal also discussed plans for a new access road from the mainland to Artificial Island. A decision from the Nuclear Regulatory Commission is not expected until 2013.

Susquehanna-Roseland Reliability Project Named to Federal Rapid Response Team

In October 2011, the Susquehanna-Roseland project was added to the federal government's Rapid Response Team for Transmission. This team is aimed at coordinating and expediting the federal permitting process for critical infrastructure upgrades.[2]

The Susquehanna-Roseland power line is a joint project of PPL Electric Utilities in Pennsylvania and PSE&G in New Jersey. The line will connect substations in Berwick, PA and Roseland, NJ. The project already has been approved by both the New Jersey Board of Public Utilities and the Pennsylvania Public Utility Commission. In addition to maintaining electric system reliability, the Susquehanna-Roseland project will create more than 2,000 jobs during the multi-year construction of the 145-mile line.[3]

Significant Storm-Related Power Outages

On August 28, 2011, Hurricane Irene affected the service territory of PSE&G, leaving more than 800,000 customers without electricity. All of those customers had their electricity restored within six days, except for approximately 1,000 whose restoration depended on the recession of surrounding flood waters. The hurricane also interrupted the gas service of approximately 30,000 customers. Similar circumstances with flooding led to the delay of full gas service restoration for 16,000 customers.[4]

On October 29, 2011, an early snowstorm affected the service territory of PSE&G, leaving more than 500,000 customers without electricity. The storm was reported by New Jersey Governor Chris Christie to have caused more significant damage to the electric infrastructure than Hurricane Irene.[5] All of those customers had their electricity restored within eight days.[6]

[2] http://www.pseg.com/info/media/newsreleases/2011/2011-10-05.jsp
[3] Ibid.
[4] http://www.pseg.com/info/media/newsreleases/2011/2011-09-04.jsp
[5] http://www.pseg.com/info/media/newsreleases/2011/2011-10-31a.jsp
[6] http://www.pseg.com/info/media/newsreleases/2011/2011-11-06.jsp

INTERVIEW LIST

Date	Interviewer Name	Interviewee Name	Interviewee Title	Subject Matter
1/26/2010	Frank DiPalma/Ramon Saenz	Bill Labos, John Hearon, Bob Felton and Kim Hanemann	Dir Asset Reliability, Mgr Asset Information & System Policy, Dir Utility Operations Services, Dir Delivery Projects & Construction	Contractor Management and Performance, Distribution System Reliability, Distribution Operations and Maintenance,
1/26/2010	Frank DiPalma/Ramon Saenz	Paul Napoli and Jeff Mueller	Dir, Transmission Business Strategy, Mgr ERO/RE Pol & Stn Interface	Pooling, Interchange, and Economic Dispatch
1/25/2010	Frank DiPalma/Ramon Saenz	Esam Khadr and Ken Tanis	Dir Electric Delivery Planning, Design Engineer	Distribution Load Forecast
1/27/2010	Frank DiPalma/Ramon Saenz	Fred Lynk, Joe Prusik, and Ron Wharton	Mgr Mkt Strategy & Planning, Mgr Asset Management Renewables, Dir Electric System Operations Ctr	Distribution Load Management and Control, Electric Supply and Demand Side Management
1/27/2010	Frank DiPalma/Ramon Saenz	Hal Izzo and Tony Mannarino	Distribution Mgr Electric Engineering, Technical Support Team Ldr	Distribution Electric Engineering Design
1/27/2010	Frank DiPalma/Ramon Saenz	Tim McGuire, Ed Gray, Fred Clark and Martin Innis	Asset Integration Ldr, Mgr New Business, Project Mgr, Project Mgr	Distribution Construction Budget, Distribution Construction, Distribution Operations and Maintenance Budget
1/28/2010	Frank DiPalma/Ramon Saenz	John Hearon and Richard Wernsing	Mgr Asset Information & System Policy, RCM Expert	Smart Grid Activities
2/2/2010	Bob Welchlin	Deborah McGrane, and Jeff Blocher	Mgr. Planning Reporting & Analysis (on phone), Mgr Mgt Accounting & Controls	Service company annual and five-year planning, budgeting, reporting, allocation procedures, relationships with practice area analysts.
2/2/2010	Christopher Pioli	John Scarlata, Dave Caffery, John DeAnna	Managing Dir Fuel Supply & Trading, Dir Portfolio Mgr & Regulatory, Mgr Gas Trading	Energy Resources & Trading, Gas Supply
2/2/2010	Frank DiPalma/Ramon Saenz and/or Sal Marano	Tony Fuhrman, Wade Miller, Barbara Altenburg, and Alice MacPhee	Asset Strategy Ldr; Planning & Design Mgr; Pipeline Integrity Mgr, Mgr Asset Information & System Policy	Gas System Planning
2/2/2010	Frank DiPalma/Ramon Saenz and/or Sal Marano	Kevin Powers and Tim Lauder	Mgr Process Operations & Technical Svc, Technical Support Team Ldr	Contract Management and Damage Prevention
2/3/2010	Christopher Pioli	Terry Moran, Calvin Ledford	Dir Retail Business, Mgr Energy Settlements	Third Party Suppliers
2/3/2010	Frank DiPalma/Ramon Saenz and/or Sal Marano	Joseph Martillotti and Greg Kyriacos	Mgr Processes Ops & Resources, District Mgr Gas Distribution & Appl Svc	Distribution Operations and Maintenance and Contractor Management
2/3/2010	Frank DiPalma/Ramon Saenz and/or Sal Marano	Andy Tummino, Allan Rosen, and Tony Fuhrman	Dir Gas Asset Mgmt, Planning & Design Mgr, Asset Strategy Ldr	Gas Asset Management
2/4/2010	Bob Welchlin	Rich Aicher, Joan Hebert, and Jeff Blocher	Mgr SAP Strategy and Planning, Mgr Utility Business Strategy, Mgr Mgt Accounting & Controls	Transactions Between PSE&G (utility) and affiliates
2/4/2010	Bob Welchlin	Joe Bassolino, Rich Aicher	Mgr Business Development, Mgr Mgt Accounting & Controls	Appliance Services
2/4/2010	Christopher Pioli	Steve Beckenstein, Ann Feit	Mgr Internal Audit, Mgr Internal Audit Services - Projects	Internal Audit
2/4/2010	Christopher Pioli	Tony Robinson, Paul Bralczyk	Dir BGS/BGSS, Mgr BGSS	BGS/BGSS
2/23/2010	Christopher Pioli	Daniel Furlong, Chuck Trefurt	Assistant Controller - PSE&G, Mgr PSE&G Revenue & Energy Act	Services Group - Accounting Department
2/23/2010	Frank DiPalma and/or Christopher Pioli	Kim Hanemann, Bill Labos, Tony Furhman	Dir Delivery Projects & Construction, Dir Asset Reliability, Asset Strategy Ldr	T&D Major Projects Group
2/24/2010	Christopher Pioli	Fritz Lark, Mark Kahrer	VP - Business Analysis, VP Finance - PSE&G	Utility Business Topics
2/24/2010	Christopher Pioli	Stephen Wreschnig, Tony Furhman, Jim Westervelt	Dir E&G Sales & Rev Forecasting, Asset Strategy Ldr, Mgr Gas Systems Operations	Gas Utility Forecasting Group
3/2/2010	Gary Harpster	Terrence Moran, Bob Krauss	Dir Retail Business Services, Mgr Credit & Contract Aministration	Power Contract Admin. & Settlement Process
3/3/2010	Gary Harpster	Anthony Robinson, Steve Huber, Sy Wodakow	Director BGS/BGSS Services, Mgr BGS, Mgr NUG Contracts	Power Supply
3/3/2010	Gary Harpster	James Calore, Jodi Moskowitz, Terry Moran, Bob Green	Mgr Interconnection Planning, General Reg Ops/Compliance Counsel	Interconnection Agreements with Generators
4/13/2010	Ken Tatum	Cora Brina, Ramona Blake, Jeff Smith	VP HR Client Services, Diversity and Inclusion Manager, Affirmative Action Compliance Officer	PSEG and affiliate org. structure and Diversity, EEO and AA
4/14/2010	Ken Tatum	Vincent Labbate, Randi Casey	Dir Performance and Development, Director Talent Acquisition	EE Productivity, Performance and Training
4/14/2010	Ken Tatum	Cora Brina, Charlie Miracola, Kevin Duddy, John Tiberi	VP HR Client Services, Mgr Corporate Benefits, Director Business Operations & HR Strategy, Director Labor and Employee Relations	Human Resources Org. Structure and Union Negotiations
4/26/2010	Ken Tatum	Christine De Stefano, John Bolland, Charlie Miracola	VP Comp & Benefits, Manager Corporate Compensation, Manager Corporate Benefits	Compensation
6/7/2010	Robert Welchlin/Chad Epps	Bob Rankin, Joe Jackson	Dir Strategic Sourcing, Mgr Procurement Governance	Supply Chain
6/8/2010	Robert Welchlin/Chad Epps	Rich Franklin, Ginny Walker	Mgr Corp Properties, Mgr Headquarter Services	Facilities
6/8/2010	Robert Welchlin/Chad Epps	Brad Huntington	Assistant Treas - Corporate Finance	Insurance
6/9/2010	Robert Welchlin/Chad Epps	Rick Buro	Mgr Transportation and Equipment	Fleet Services
6/9/2010	Robert Welchlin/Chad Epps	Judy Price	Mgr Records Mgmt & Library Services	Records

INTERVIEW LIST

Date	Interviewer Name	Interviewee Name	Interviewee Title	Subject Matter
6/10/2010	Robert Welchlin/Chad Epps	Bob Czyzewski	Managing IT Business Partner	IT
6/10/2010	Robert Welchlin/Chad Epps	Maria DaSilva, Nancy Sobelson	Mgr Legal Business & Admin Support, Outside Counsel & Client Rlshp Mgr	Legal
6/11/2010	Robert Welchlin/Chad Epps	Libby Price, Frank McCormick, Mark DeVoti	Mgr Projects, Analysis & System Support; Mgr Asset Protection & Preparedness; Homeland Security Mgr.	Security
7/7/2010	Greg Oetting/Howard Lubow	Bill Metzger and Steven Beckenstein	Vice President – Internal Auditing Services, Mgr Internal Audit Services	Internal Auditing
7/7/2010	Greg Oetting/Howard Lubow	Daniel Furlong	Assistant Controller - PSE&G	Organizational responsibilities vs. parent/service company (see DiRisio subjects)
7/8/2010	Greg Oetting/Howard Lubow	Derek M. Di Risio	Vice President and Controller	Internal Controls, Deficiencies, Staffing, Impairments
7/8/2010	Howard Lubow/Greg Oetting	Mark Kahrer	Vice President - Finance (PSE&G) - reports to LaRossa	Organizational responsibilities vs. parent/service company (see Dorsa subjects)
7/9/2010	Howard Lubow/Greg Oetting	Laura L. Brooks	Vice President - Risk Management and Chief Risk Officer	Risk management, historical SOX compliance responsibilities
7/9/2010	Howard Lubow/Greg Oetting	Morton A. Plawner	Vice President and Treasurer	Rating Agency Interaction, Dividend Policy, External Financing, Liquidity, Cash Management
7/20/2010	Chad Epps	Joseph Bassolino	Manager Business Development AS	BPU Appliance Service filing and supporting cost support documentation
7/20/2010	Chad Epps	Jeff Blocher, James Manhart, Gurunath Netravali, Leung Cheung	Mgr Mgt Accounting & Controls, et al	BPU Appliance Service filing and supporting cost support documentation
8/2/2010	Howard Lubow	Anne E. Hoskins / Richard T. Thigpen	Vice President – Federal Affairs and Policy / Vice President State Governmental Affairs (General Counsel's department)	Lobbying, Government Interaction
8/2/2010	Howard Lubow/Greg Oetting	Patricia McLaughlin	Vice President - Finance (Energy Holdings & Serv Corp) - reports to Dorsa	Organizational responsibilities vs. parent/service company (see Dorsa subjects)
8/3/2010	Chad Epps	Arthur Guida	Dir External Affairs & Cmt Dev (Customer Operations department)	External Relations
8/3/2010	Howard Lubow/Greg Oetting	Hugh Mahoney	General Compliance Counsel	Corporate Ethics and Policies
8/4/2010	Howard Lubow/Greg Oetting	Morton A. Plawner	Vice President and Treasurer	Rating Agency Interaction, Dividend Policy, External Financing, Liquidity, Cash Management
8/4/2010	Howard Lubow	Kevin J. Quinn	Vice President - Corporate Planning	Corporate Planning
8/5/2010	Howard Lubow	Margaret Pego	SVP - Human Resources	Human Resources Org. Structure and Union Negotiations
8/5/2010	Howard Lubow/Greg Oetting	J.A. Bouknight, Jr.	Executive Vice President - Law, SVP - Law	Legal Organization, Outside Counsel, Corporate Ethics and Policies, Commitments and Contingencies, Ring-Fencing
8/18/2010	Greg Oetting	Jane Bergen	Dir Customer Contact	Call Centers, Performance Metrics
8/18/2010	Greg Oetting	Vic Viscomi, Mike Kelly	Dir Projects, Mgr Operations - Billing	Billing, bad debts, dunning, deferred payment plans
8/19/2010	Greg Oetting	Joe Bassolino, Robert Blache	Mgr Business Development AS, District Mgr Gas Distribution & Appl Svc	Customer premise work/ appliance service work/ dispatch
8/19/2010	Greg Oetting	Dave Daly	VP Asset Mgmt & Centralized Srvs	iPower Implementation
8/20/2010	Greg Oetting	Bill Nash	Mgr Labor Relations	Customer service process improvement efforts, performance
9/30/2010	Ken Tatum	Kevin Duddy, Joe Maceiras	Dir Business Ops & HR Strategy, Spv Employee Services	Demonstration use of the SAP HR module
10/7/2010	Gary Harpster	Napoli, Marinelli, Wharton	Dir, Transmission Business Strategy, Dir Electric System Operations Ctr, et al.	Utility Operations
10/8/2010	Gary Harpster	Esam Khadr	Dir Electric Delivery Planning	Utility Operations
10/8/2010	Gary Harpster	Al Matos, Fred Lynk	Mgr Mkt Strategy & Planning, et al.	Utility Operations
10/12/2010	Howard Lubow/Greg Oetting	Shirley Ann Jackson	Director, Chairperson of the Finance Committee	Board and Committee Matters
10/13/2010	Howard Lubow/Greg Oetting	Conrad Harper	Director, Chairperson of the Corporate Governance Committee	Board and Committee Matters
10/14/2010	Howard Lubow/Greg Oetting	Albert Gamper, Jr.	Director, Chairperson of the Organization & Compensation Committee	Board and Committee Matters
10/14/2010	Howard Lubow/Greg Oetting	Thomas Renyi	Director, Chairperson of the Audit Committee	Board and Committee Matters
10/14/2010	Howard Lubow/Greg Oetting	Richard Swift	Director, Presiding (Lead) Director	Board and Committee Matters
10/19/2010	Howard Lubow/Greg Oetting	Caroline Dorsa	Executive Vice President and CFO	Financial Objectives, External Financing, Strategic Planning, SOX compliance, Internal Controls, Investor Relations
10/21/2010	Howard Lubow	Randall E. Mehrberg	Executive Vice President - Strategy & Development	Strategic Planning, Budgeting, Balanced Scorecard
10/22/2010	Howard Lubow	Tamara L. Linde	Vice President - Regulatory	Rate Filings, Regulatory Climate, Initiatives
10/22/2010	Howard Lubow/Greg Oetting	Ralph A. LaRossa	President and Chief Operating Officer	System Reliability, Strategic Planning, Unregulated Businesses, iPower
12/7/2010	Howard Lubow/Greg Oetting	Ralph Izzo	Chairperson President and CEO	Board and Committee Matters Strategic Planning Unregulated Businesses

2. Overview of Affiliate Relationships and Transactions

Summary of Findings

PSEG Services (Chapter 3)

1. During the 2007-2009 review period, internal control of PSEG Services' budgeting, accounting and cost distribution procedures was adequate to inhibit significant opportunities for cross-subsidization of the activities of non-regulated operations by regulated utility PSE&G.

2. During the review period, PSEG Services reduced from the number of "unattributable" allocators used to distribute "Enterprise" costs incurred on behalf of the corporation as a whole from three allocators to one. The new allocator, used for all Enterprise costs beginning in 2009, is a composite of fixed assets, headcount and O&M expense. This change had a minor impact on PSE&G.

3. In addition to reducing Enterprise cost allocations to a single allocator, through the use of more targeted allocations and billings, in 2008 PSEG Services also reduced the percentage of cost included in its Enterprise cost pool from 20% to 16% of total PSEG Services costs. The primary beneficiary was the PSEG's Holdings operating company. Allocations of Enterprise costs to Holdings dropped from $3.6 million in 2007 to $1.6 million in 2008.

4. PSEG Services' allocable costs remained reasonably steady during the review period ($402 million in 2007; $451 million in 2008; $416 million in 2009). The cost spike in 2008 was primarily due to the implementation of PSE&G's new iPower (customer service) system.

5. PSEG Services continued to refine billing and allocation processes during the review period. In general, as discussed above, these refinements tended to make billing processes more direct. The Holdings operating company, which experienced an overall reduction of about 23% in service company charges, was the largest beneficiary of these changes. However, when viewed from the perspective of total distributed cost, and in the context of the procedures and controls in place, Overland does not believe the changes made during the review period are cause for concern.

Non-Utility Generation Contracts (Chapter 15)

1. PSE&G negotiates with non-utility generators on matters related to power purchases. In 2008 PSE&G negotiated on two separate matters with generators under three large contracts. PSEG Energy Resources and Trade, LLC (ER&T) has extensive commercial relationships with these sellers. In both cases PSE&G's negotiating team included an ER&T senior commercial attorney. This created a risk that PSE&G's interests would be compromised to preserve ER&T's business

relationships with the sellers. ER&T attorneys should not be involved in negotiations on behalf of PSE&G when the parties to the negotiations are power generators with which ER&T has separate commercial relationships.

PSEG Power (Chapters 16)

1. PSEG Power (Power) owns 90 percent of the generating capacity located in PSE&G's transmission zone and 33 percent of the capacity in PJM's Eastern Mid-Atlantic Area Council (EMAAC) region. During the review period Power was PSEG's most profitable segment during our review period. Over the period 2007 to 2010, it averaged a 27 percent return on equity.

2. Power provides approximately 36 percent of New Jersey's BGS-FP (fixed price) power supply. In 2009 Power provided 43 percent of PSE&G's BGS-FP supply. The number of BGS-FP tranches awarded to PS Power is consistently close to the state-wide and PSE&G load caps. The magnitude and persistence of Power's BGS-FP market share raises concerns about the competitiveness of the underlying market.

3. PJM's control of transmission significantly reduces the risk of affiliate abuse in transmission operations and planning.

4. PSE&G has no written plans or procedures for ensuring the operational separation of most PSE&G and Power employees. Functional separation is an important safeguard for managing incentives created by joint ownership of regulated and non-regulated operations.

5. Power uses PSE&G's Energy Management System to obtain information about generating plants and PJM system data available to all generators. PSE&G charges Power 18.75 percent of the costs of EMS, using an allocation factor based on engineering judgment. The allocation factor is poorly documented.

6. The joint management of PSE&G's basic gas supply service (BGSS) and Power's generation gas supply creates a risk that PSE&G's BGSS customers will subsidize Power's fuel costs.

7. PSE&G provides gas transportation to Power at discounted rates. PSE&G provided these services for many years without a written contract and without requiring Power to demonstrate a need for the discounts. In this regard, this shows a lack of appreciation for and commitment to affiliate transactions safeguards.

8. PSEG directs and controls both PSE&G and Power. PSEG tends to caucus with generation interests at PJM and FERC. PSEG usually votes for positions favored by a majority of generation interests at PJM, and PSEG's FERC positions often coincide with those taken by generation

interests. The alignment of PSEG and generation owner positions raises concerns that the utility's positions are being shaped to advance the interests of Power.

9. The process of developing PSEG's unified corporate positions includes commingling of utility and merchant generator interests and views. PSE&G defers to Power's market expertise on PJM issues. Relying on Power for expertise on market issues provides Power with an opportunity to shape utility positions to advance merchant interests.

10. The process by which PSEG balances the interests of the PSE&G's utility distribution customers with the interests of Power when developing unified corporate positions is undocumented. The lack of documentation impedes regulatory oversight.

Interconnection and Non-Power Services (Chapter 17)

1. In 2009 PSE&G prepared a transmission impact study for Power outside of the PJM interconnection process. The study identified network upgrades required to add a new nuclear unit adjacent to Salem and Hope Creek. The study used ratepayer-funded resources and provided an opportunity to coordinate PSE&G's PJM transmission planning positions with Power's interests. PSE&G charged Power a lump-sum fee of $105,000 for the study. PSE&G did not track the actual cost of preparing the study. Regulatory oversight of affiliate charges is difficult when the cost of providing the services is not tracked.

2. PSE&G standardized its interconnection agreements with PS Power in 2010. The new agreements will improve PSE&G's internal controls over interconnection service billings.

3. PSE&G's charges to PS Power for interconnection attachment facility maintenance appear to be reasonable with limited exceptions.

4. PSE&G did not charge PS Power for meter inspection and testing services provided prior to 2010. PSE&G will charge approximately $200,000 a year for those services under the new interconnection agreements.

5. PSE&G uses local distribution facilities to deliver station power to PS Power generating plants. PSE&G provides those services at a large discount from tariffed rates. The discounts totaled approximately $4.3 million in 2009. PSE&G should charge tariff rates for those services. If PSE&G believes discounts are justified by a legitimate by-pass threat, it should provide estimates of PS Power's by-pass costs and explain its discounting strategy.

6. PSE&G charged $7 million to PS Power for equipment maintenance and construction in 2009. PSE&G's internal controls over those charges are inadequate. From an internal control perspective, PSE&G treats the work it does for PS Power the same as utility work.

7. PS Power charged $16 million to PSE&G in 2009 for non-power goods and services. Most of the services were provided by PS Power's Maplewoods Testing Service (MTS), System Maintenance Division and Central Maintenance Shop.

8. The BPU's Holding Company Rules prohibit PSE&G from purchasing any services from affiliates that it can obtain "on more advantageous terms" by other means. The rules require PSE&G to review its purchases from PS Power for compliance with that requirement by April 2012.

9. PSE&G's internal controls over charges from PS Power are inadequate. From an internal control perspective, PSE&G treats charges from PS Power the same as internal utility charges. PSE&G does not implement any controls beyond those that apply to work it performs internally. PSE&G's management reports for charges from PS Power are inadequate.

EDECA Affiliates and Prior EDECA Audit Recommendations

1. During the review period PSE&G had two minor affiliates classified as "affected affiliates" under the Electric Discount and Energy Competition Act Affiliate Standards (EDECA).[1]

2. Demand Management Company is a two-employee operation that earns income by sharing electricity savings with customers from the installation of energy efficiency equipment. PSEG Solar Source has five employees. In 2010 it operated solar generation equipment for three facilities, one of which was in New Jersey. Approximately two MW out of Solar Source's 29 MW of operational capacity in 2010 was located in New Jersey at the Mars Snack Food plant in Hackettstown. The remaining 27 MW was located in Ohio and Florida. PSE&G's compliance with the EDECA rules with respect to these two minor affiliates is discussed in its Compliance Plan. Overland found nothing during the audit to indicate that PSE&G was not compliant with EDECA with respect to these affiliates.

3. Six of twenty-four recommendations made in the prior EDECA audit were contested according to the company or the BPU. The disposition of these recommendations was never formally resolved. Some of the recommendations are no longer relevant eight years after being made, but two continue to remain outstanding.

4. In implementing a recommendation made in the prior EDECA audit, an affiliate did not pay all of the accumulated interest it owed to PSE&G. However, this unreimbursed interest only amounted to approximately $8,000 through the end of 2010.

[1] Most of the business activities subject to the EDECA affiliate standards are associated with appliance services, which are provided by a business unit within PSE&G. Appliance services are the subject of Chapter 4 of this report. Appliance services are not discussed in this chapter because they are provided by the utility, not by an affiliate.

Recommendations

1. Attorneys who represent PS Power in power market commercial matters should be excluded from PSE&G's NUG contract negotiating teams (Chapter 15).

2. PSE&G and Power should develop compliance plans to ensure utility and Power personnel operate independently to the maximum extent possible (Chapter 16).

3. PS&EG should track meetings attended by both utility and Power personnel (Chapter 16).

4. PSE&G should develop a compliance plan to limit Power's access to non-public utility information (Chapter 16).

5. PSE&G should document the basis for the EMS cost allocation factor (Chapter 16).

6. PSE&G should review the advantages and disadvantages of outsourcing BGSS gas procurement to ER&T (Chapter 16).

7. PSE&G should develop and advocate separate utility positions on PJM and FERC issues (Chapter 16).

8. If PSEG continues to vote a unified corporate position at PJM, it should join the generation owners' sector (Chapter 16).

9. PSE&G should track the costs of preparing technical studies for PS Power. (Chapter 17).

10. PSE&G should charge PS Power for the interconnection metering costs it incurred but did not bill to PS Power prior to 2010 (Chapter 17).

11. PSE&G should compare reported station power values to benchmark values on a monthly basis (Chapter 17).

12. PSE&G should charge tariff rates for station power delivered over local distribution facilities (Chapter 17).

13. PSE&G should improve its internal controls over charges to PS Power. PSE&G should enter into a Services Agreement with PS Power (Chapter 17).

14. PSE&G should require PECO to stop depositing utility funds in a PS Power bank account (Chapter 17).

15. The New Jersey Radiation Response Fund fee should be paid directly by PS Power (Chapter 17).

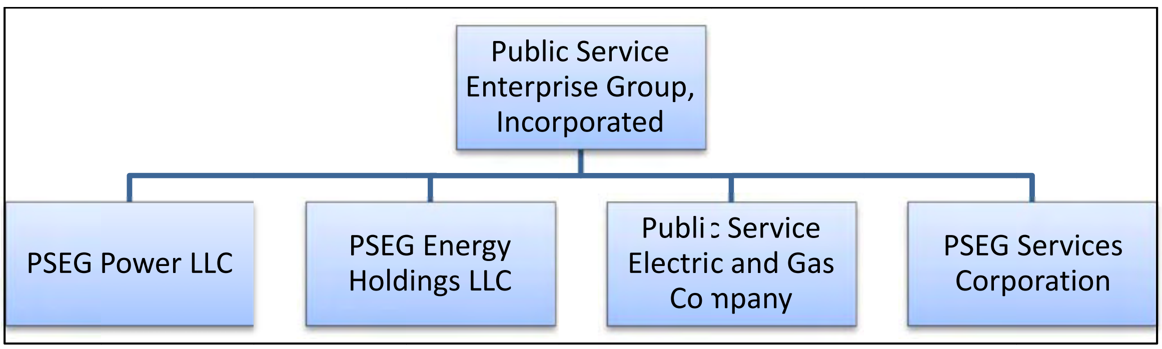
16. PSE&G should review its purchases from PS Power for compliance with the BPU's Holding Company Rules (Chapter 17).

17. PSE&G should encourage the BPU to rule on relevant, outstanding issues from the 2004 audit and any matters that are contested in the current audit. For any recommendations not implemented, the company should file a status report with the BPU every three months until a final decision is rendered (Prior EDECA audit issues, discussed below).

Summary of PSEG's Affiliate Structure and Operating Companies

The flow chart below summarizes the business structure of PSEG and PSE&G's place in that structure.

Table 2-1 – PSEG Business Structure



PSEG's operations are conducted through three segments, which correspond with the following "operating" subsidiaries: PSEG Power (Power), PSE&G (Utility) and PSEG Holdings (Holdings).

<u>PSEG Power</u> – Power owns and operates generation stations and sells, markets, and trades energy and energy-related products in the energy marketplace. Power consists of the following components:

- <u>PSEG Fossil</u> - owns and operates the company's steam, combined cycle and combustion turbine generating stations, including coal, natural gas and oil-fired units.

- <u>PSEG Nuclear</u> – owns the Hope Creek nuclear station and partially owns the Salem and Peach Bottom generating stations. Peach Bottom is operated by Exelon Generation.

In total, the Fossil and Nuclear segments within Power own approximately 13,500 MW of capacity. PSEG's generating facilities are summarized below.

Table 2-2 – PSEG Power, Generation Facilities Summary

PSEG Power Generation Facilities Summary December 31, 2010					
Facilities	Location	Capacity (MW)	Pct Owned	Owned Capacity	Fuels
Steam (Base & Load Following)					
Keystone	PA	1,711	23%	391	Coal
Conemaugh	PA	1,711	23%	385	Coal
Hudson	NJ	930	100%	930	Coal & Gas
Others	NJ & CT	2,047	100%	2,047	Coal & Oil
Total Steam		6,399		3,753	
Nuclear (Base Load)					
Hope Creek	NJ	1,197	100%	1,197	Nuclear
Salem (2 units)	NJ	2,337	57%	1,342	Nuclear
Peach Bottom (2 units)	PA	2,245	50%	1,122	Nuclear
Total Nuclear		5,779		3,661	
Combined Cycle (Load Following)					
Bergen	NJ	1,178	100%	1,178	Gas
Linden	NJ	1,230	100%	1,230	Gas
Bethlehem	NY	755	100%	755	Gas
Total Combined Cycle		3,163		3,163	
Peaking					
Combustion Turbine	Mainly NJ	2,777	99%	2761	Gas & Oil
Pumped Storage Total	NJ	400	50%	200	
Total Capacity		**18,518**		**13,538**	
Source: PSEG Form 10K, Reporting Year 2010					

- Energy Resources and Trade – ER&T manages PSEG Power's generation portfolio and basic gas supply service, purchases fuel, and buys and sells electricity and gas. Among its primary responsibilities are to market the output of Power's generating stations and to dispatch this output to the grid. ER&T's primary geographic areas of focus are the PJM, New York, New England and Electric Reliability Council of Texas (ERCOT) market areas. It provides risk management service and markets physical and financial energy and energy-related products throughout the greater Northeast region and Texas. ER&T describes its operation as "among the few trading operations with an integrated trading / generation model."[2] In addition to marketing company-owned generation, "trades a range of products, including electricity, generating capacity, natural gas, emission credits, transmission rights, coal and oil."[3]

[2] http://www.pseg.com/family/power/resources_trade
[3] http://www.pseg.com/family/power/resources_trade

In addition to the operating segments, there are a number of legal entities within Power that serve various purposes.

- PSEG Power Fuels – holds PSEG's interest in Keystone Fuel LLC and Conemaugh Fuel LLC, the entities that purchase fuel for the Keystone and Conemaugh generation stations.
- PSEG Power Development – supports the development activities of PSEG Power.
- Odessa-Ector Power Partners Services, LLC – Through this entity, PSEG owns a 2000 MW natural gas-fired power generating facility in Ector County, Texas. This plant was to be purchased by High Plains Diversfied Energy, a holding company based in Lubbock, TX for $335 million.[4] In June, 2011, the deal came undone due to lawsuits and a judge's ruling. PSEG continues to own the plant.[5]
- PSEG Power Capital Investment Co. LLC – formed to provide financing to PSEG Power and its subsidiaries.[6]

PSE&G – Public Service Electric and Gas (Utility) is the regulated utility that transmits and distributes natural gas and electricity to end users in its service territory. It also maintains one of the largest utility-owned appliance services businesses in the U.S. The utility has approximately 2.1 million electric customers and 1.7 million gas customers as of December 31, 2009. PSE&G operates solely in New Jersey, covering the most densely populated, commercialized, and industrialized parts of the state.[7]

Energy Holdings – PSEG Energy Holdings (Holdings) has historically managed leveraged lease investments and domestic generation projects. During and prior to the review period, PSEG sold off much of its international leveraged lease businesses. As of December 31, 2010, the only international power plant investments PSEG continued to maintain were in Venezuela. In addition, Holdings owns a portfolio of generating facilities in the US, including oil, coke, biomass, hydro and solar facilities. As of December 31, 2010, approximately 17% (36 of 206 MW) of Holdings' U.S. portfolio consisted of renewable resources. Below is a summary of Holdings domestic and international generation investments.

[4] http://www.oaoa.com/articles/plains-58659-high-power.html
[5] http://www.oaoa.com/articles/pseg-66400-lubbock-sold.html
[6] Response to Discovery, OC-1.
[7] PSEG 2009 10-K.

Table 2-3 – PSEG Energy Holdings, Generation Facilities Summary

PSEG Energy Holdings Generation Facilities Summary December 31, 2010					
Facilities	Location	Capacity (MW)	Pct Owned	Owned Capacity	Fuels
U.S.					
Kalaeloa	HI	208	50%	104	Oil
GWF	CA	105	50%	53	Pet. Coke
Hanford	CA	27	50%	13	Pet. Coke
Bridgewater	NH	16	40%	6	Bio
Conemaugh Hydro	PA	15	100%	1	Hydro
Hackettstown	NJ	2	100%	2	Solar
Wyandot	OH	12	100%	12	Solar
Jacksonville	FL	15	100%	15	Solar
Total U.S.		400		206	
International					
Turboven	Venezuela	120	50%	60	Gas
Turbogeneradores de Maracay	Venezuela	40	9%	4	Gas
Total International		160		64	
Total Capacity - Energy Holdings		**560**		**270**	
Source: PSEG Form 10K, Reporting Year 2010					

In addition, there are a number of legal entities within Power that serve various purposes.

- PSEG Energy Technologies Asset Management Company LLC – This company holds assets from former subsidiaries PSEG Energy Holdings and PSEG Energy Technologies, Inc.

- Enterprise Group Development Corporation – This is a nonresidential real estate property management business.

- PSEG Resources LLC – Resources is the entity that contains investments in energy-related leveraged leases to PSEG's operating subsidiaries. PSEG is in the process of selling off these assets. In this business, PSEG typically purchased energy-related assets for to be leased back to the sellers. The business purpose was to obtain a fixed rate of return through the income from the lease payments as well as the tax benefits of interest and depreciation deductions. As of October 31, 2009, approximately 60 percent of the $1.747 billion in leveraged leases was invested in energy generating leases, with the remainder invested in energy transmission and distribution assets as well as commercial real estate.[8] As of December 31, 2009, PSEG Resources had $1.6 billion in leveraged leases.[9]

[8] Response to Discovery, OC-131.
[9] PSEG 2009 10-K.

- PSEG Global LLC – Global participates in the development and operation of projects in the generation and distribution of energy, which includes cogeneration and independent power-production (IPP) facilities and electric distribution companies.[10]

PSEG Services Corp - PSEG Services provides centralized management and administrative services that provide benefits to more than one operating company (OC). During the 2007-2009 approximately 59% of the costs incurred by PSEG Services were charged to PSE&G (Utility). Approximately 37% was charged to Power, and an average of about 4.5% was charged to Holdings. Chapter 3 is devoted to PSEG Services and its charges to PSEG's three operating companies (Power, Utility and Holdings).

Summary of Transactions Between PSE&G and Affiliates

Significant services provided to PSE&G by its affiliates during the audit period included the following:

- Energy Transactions – Power provides PSE&G with electric generation (BGS, or Basic Generation Service) and gas supply (BGSS, or Basic Gas Supply Service). These two services accounted for over 99% of the amount billed to PSE&G by Power in 2009.[11] The relationship between PSE&G and PSEG Power is discussed in Chapter 16.

- Gas Transportation Service – PSE&G provides interruptible gas transportation service to Power. The gas is purchased by Power from non-affiliated suppliers and transported to Power's generating plants using PSE&G pipeline facilities. This service is provided at rates that are lower than the rates charged to similarly-situated non-affiliated generators. PSE&G discloses its charges to Power in its annual BGSS reconciliation charge filing and the BPU has approved the resulting BGSS rates. This is discussed in more detail in Chapter 16.

- Power's Use of PSE&G's Energy Management System (EMS) – Power uses PSE&G's EMS to obtain information related to generating plants, as well as PJM system data available to all generators. 18.75% of the costs of EMS are charged to Power. This is discussed further in Chapter 16.

- Service Company Transactions – PSE&G received a significant amount of service during the audit period from PSEG Service Company. The Service Company provided corporate and shared utility and competitive energy operating services to most of PSEG's operating subsidiaries. Service Company employees also managed the investment (non-operating) subsidiaries. In addition to providing services, the Service Company also assigned employee benefit costs to PSE&G that the Service Company paid on behalf of PSE&G employees. The Service Company billed PSE&G approximately $478 million in 2007, $545 million in 2008, and $481 million in 2009 for services

[10] Response to Discovery, OC-1.
[11] Ibid.

provided.[12] Chapter 3 is devoted to discussion of the service company and its transactions with affiliates.

- Interconnection – PSE&G interconnects with Power and maintains interconnection agreements with Power which were revised and standardized in 2010. FERC and PJM control the interconnection process for all new generation. During the review period, PSE&G prepared a transmission impact study for Power outside the normal PJM interconnection process. Interconnection is discussed in Chapter 17.

- Maintenance & Testing Services – Power provides maintenance and testing services to PSE&G. During the review period much of this involved services provided by Power's Maplewoods Testing Services (MTS) System Maintenance Division and Central Maintenance Shop. These services are discussed in Chapter 17.

- PSEG (Parent) Transactions – Certain employee benefits earned by PSE&G's employees were initially paid by the parent company PSEG. These costs were eventually passed through to the utility. PSEG billed its utility subsidiary for costs relating to employee stock options as well as deferred compensation. In addition to these costs, PSE&G is allocated a portion of the parent's income or loss.[13]

- Dividends to the Parent – PSE&G pays dividends to PSEG. PSE&G's paid the parent $200 million in dividends in 2007. There were no dividend payments in 2008 or 2009.[14] [15]

The table below summarizes charges to the Utility business segment (PSE&G) by affiliates. It excludes dividends paid to the parent.

[12] Response to Discovery, OC-58 UPDATE
[13] Response to Discovery, OC-58.
[14] Response to Discovery, OC-33 UPDATE
[15] For comparison purposes, per response to OC-33 Power paid $1.075 billion, $500 million and $725 million in dividends to the parent in 2007, 2008 and 2009 (through September), respectively.

Table 2-4 – Summary of Charges To PSE&G By Affiliates

Summary of Charges To PSE&G By Affiliates 2007-2009 Amounts in $000s			
Facilities	**2007**	**2008**	**2009**
Power:			
BGS	1,162,387	1,451,993	1,321,539
BGSS	2,208,307	2,315,732	1,838,155
Other	11,469	19,699	18,114
Subtotal Power	3,382,163	3,787,424	3,177,808
Parent (Enterprise)	6,154	10,056	5,480
Holdings	-	-	39
PSEG Services	478,410	545,047	481,207
Total	**3,866,727**	**4,342,527**	**3,664,534**
Source: OC-58			

Charges by PSE&G to Affiliates[16]

Charges by the Utility operating company to affiliates include the following:

- Services Provided to Power – PSE&G provides peak shaving services to Power. PSE&G provides interconnection attachment facility maintenance to Power. During the review period PSE&G provided Power with meter inspection and testing services which it did not charge to Power. Beginning in 2010, Power was to be charged for the services. PSE&G uses its distribution facilities to deliver station power to Power's generating plants at discounted rates. Services provided by PSE&G to Power are discussed in Chapter 17.

- Services Provided to PSEG Services – PSE&G provides the use of fleet vehicles and the Mulberry St. garage to the Service Company.

- Charges to Holdings – PSE&G bills Holdings for pensions funded by PSE&G associated with pension-eligible employees that work for a company in Holdings.

- Charges to the Parent – Amounts paid by third parties for Utility damages claims and vendor refunds are deposited into the parent's (PSEG Corp's) bank account. PSE&G then bills the parent to obtain these amounts.

[16] Response to Discovery, OC-59.

The table below summarizes these transactions for the years 2007-2009.

Table 2-5 – Summary of Charges By PSE&G To Affiliates

Summary of Charges By PSE&G To Affiliates 2007-2009 Amounts in $000s			
Facilities	**2007**	**2008**	**2009**
Power:			
Peak Shaving	3,566	3,079	3,595
Other	35,325	32,082	24,427
Subtotal Power	38,891	35,161	28,022
Parent Reimbursements	57,901	50,634	37,850
Holdings	363	574	188
PSEG Services	683	483	924
Total	**97,838**	**86,852**	**66,984**
Source: OC-59			

Compliance with EDECA Standards

In 2000, New Jersey implemented the Electric Discount and Energy Competition Act (EDECA). EDECA includes rules governing affiliate relations, competition, accounting and reporting for utilities that provide retail services in competitive markets. The rules regulate certain aspects of the relationship between New Jersey utilities and their affiliates that provide competitive non-regulated retail services (services to end users). EDECA was crafted to ensure that affiliates providing non-regulated retail products or services are not given cost, resource, or marketing advantages by virtue of their affiliation with the utility. More specifically, EDECA serves to ensure that non-regulated affiliates do not obtain an unfair advantage in New Jersey markets by selling at an artificially low price due to subsidy by the utility or its holding company; by gaining access to utility resources, such as customer lists, that are not available to competitors; or by creating an impression that what they sell are utility products or services, thereby trading on the utility's name and reputation.

EDECA Affiliate Standards cover the following broad areas:

- Non-Discrimination (N.J.A.C. 14:4-5.3) – EDECA requires that PSE&G refrain from discrimination against a competitor in favor of an affiliate.

- Information Disclosure (N.J.A.C. 14:4-5.4) – EDECA restricts the conditions under which a utility can provide customer or non-customer, non-public information to affiliates subject to EDECA. Generally, customer information can only be provided with the customer's consent. Also, generally, non-customer, non-public information cannot be made available unless it is made public (i.e., made available to others under the same conditions made available to the affiliate).

PSE&G's Compliance Plan discusses the conditions under which PSE&G's affected affiliates may obtain information from the utility. These appear to be compliant with EDECA.

- Accounting Separation (N.J.A.C. 14:4-5.5) – All PSEG subsidiaries, including PSE&G, and all affiliates that maintained a business relationship with PSE&G, maintained books separate from PSE&G (and each other) during the audit period.

- Management Separation (N.J.A.C. 14:4-5.5) – Management responsibility for PSE&G, and for many other PSEG subsidiaries was either 1) divided between the subsidiary and PSEG Service Company or 2) handled entirely by PSEG Service Company. Subsidiaries that were effectively managed by PSEG Service Company were generally those with limited or no ongoing operations (e.g. investment subsidiaries). The management of PSE&G's day-to-day operations is effectively separated from the operations of affiliates conducting non-utility businesses in "affected affiliates." EDECA section 14:4-5.5(i) allows PSE&G to share corporate support services, including corporate oversight, governance, support systems, and personnel.

Utility Competitive Services

As of 2009, the only EDECA competitive service offered to retail customers in New Jersey by PSE&G was appliance service.[17] In 2009 the Appliance Service business unit had approximately 900 employees.[18] Appliance service is discussed in detail in Chapter 4.

Prior to July, 2007, PSE&G provided water company meter reading and billing services through the trade name Sunburst Customer Solutions. These services were the subject of a classification dispute between PSE&G and the prior auditor. Specifically, the auditor classified the services as retail services subject to the EDECA Affiliate Standards. PSE&G maintained they were wholesale, rather than retail services, and were therefore not subject to the Affiliate Standards. Notwithstanding this unresolved issue, as of July 2007 PSE&G no longer offered water company meter reading or billing services.[19]

"Affected Affiliates"

Affected affiliates are affiliates of PSE&G that PSEG has determined provide competitive retail services in New Jersey, and are therefore subject to EDECA's Affiliate Standards. During the review period, two minor PSEG companies, Demand Management Co. LLC (DMC) and PSEG Solar Source LLC (both subsidiaries within Holdings), provided competitive services to customers in New Jersey and were classified by PSEG as affiliates subject to the Affiliate Standards. Neither of these affiliates were classified as an electric or gas supplier.[20]

[17] Response to Discovery, OC-60, 2009 PSE&G Compliance Plan, p. 196.
[18] Response to Discovery, OC-718.
[19] Response to Discovery, OC-60, 2009 PSE&G Compliance Plan, p. 196.
[20] Response to Discovery, OC-60, PSEG 2009 Compliance Plan, p. 254 of 278.

Demand Management Co. LLC – DMC earns income by sharing electricity savings with customers from the installation of energy efficiency equipment.[21] It was transferred to PSEG Resources in 2002.[22] In 2010, it had two active employees.[23] It is a party to public utility demand side management contracts and contracts relating to implementation of utility demand side management programs.[24]

PSEG Solar Source - In February, 2008, PSEG's Global subsidiary created PSEG Solar Source as an indirect, wholly-owned subsidiary. It installs solar panels and related equipment.[25] In August, 2009, Solar Source formed PSEG Solar Source Hackettstown LLC to operate a 2.2 MW solar generation facility associated with the Mars snack food plant in Hackettstown, NJ. Outside of New Jersey, Solar Source manages two other solar projects, including a 12 MW solar farm in Wyandot County, Ohio and a 15 MW solar farm in Jacksonville, FL.[26] Solar Source had five employees in 2010.[27]

Compliance with Affiliate Standards for DMC and Solar Source - PSE&G states that it began providing Affiliate Standards training to DMC and Solar Source employees in 2002. PSE&G states that it does not provide utility information, services, unused capacity or supply, other than permitted by the Affiliate Standards, exclusively to its affected affiliates.[28] The company indicates it processes all requests for similar services on a non-discriminatory basis and states that PSE&G employees will not impose conditions upon customers that request doing business with DMC or Solar Source in order to receive any products, services or special prices from PSE&G. PSE&G also states that it will not assign retail customers to DMC or Solar Source unless the means of assignment are available to all competitors on a non-discriminatory basis.[29]

PSEG states that it does not provide customers leads to DMC or Solar Source, solicit on behalf of the companies or release Utility-owned customer information to the affiliates without the customer's consent. Release of customer proprietary information is governed by a written agreement for the affected affiliates and all other (non-affiliated) third party suppliers. The company states that PSE&G employees will not offer or advise customers with regard to affected affiliates or other providers of these services. PSE&G states that non-public restricted information, such as information about PSE&G's gas or electricity-related services, "will only be shared with an Affected Affiliate if it is contemporaneously made available to non-affiliated entities on the same terms and made available for

[21] Response to Discovery, OC-60, 2009 PSE&G Compliance Plan, p.203.
[22] PSEG Resources and PSEG Global are the two primary components of PSEG's Energy Holdings operating company.
[23] Response to Discovery, OC-718.
[24] Response to Discovery, OC-60, 2009 PSE&G Compliance Plan, p.200.
[25] Response to Discovery, OC-60, 2009 PSE&G Compliance Plan, p.203.
[26] http://pseg.com/family/holdings/global/solar_source/index.jsp
[27] Response to Discovery, OC-718.
[28] Response to Discovery, OC-60, PSEG 2009 Compliance Plan, p. 251 of 278.
[29] Response to Discovery, OC-60, PSEG 2009 Compliance Plan, p. 252 of 278.

public inspection."[30] With respect to inquiries it receives concerning suppliers, PSE&G states that it "maintains a neutral position with regard to suppliers, including any Affected Affiliate." [31]

PSE&G states that it may provide non-public information and data which have been received from unaffiliated suppliers to an affected affiliate or other non-affiliated entities, but only after receiving written affirmative authorization from the supplier to do so.[32]

During the review period, PSE&G states that it "use[d] its billing envelope space exclusively for utility purposes" and that if it decided to offer envelope space or advertising space to affected affiliates, it would make such space available to non-affiliated entities on the same terms and conditions.[33] PSE&G states that is does not participate in joint advertising, joint marketing or joint business activities with affected affiliates DMC or Solar Source.[34] Although it states no joint marketing is conducted, PSE&G states that it "permits its employees to participate with its Affected Affiliates or another third party, at a customer's request and on a non-discriminatory basis, in a meeting that the customer has indicated not to be sales meetings. If a PSE&G employee attends such a meeting and sales matters are discussed, the role of the PSE&G employee will be limited to technical or operational discussions regarding PSE&G's provision of service to the customer." PSE&G further states that should marketing issues be raised by a customer or another party at any such meeting, PSE&G employees are instructed to reiterate the restrictions on their participation in discussions of these issues and will excuse themselves from the meeting if discussions of sales or marketing issues persist.[35] We requested the marketing and advertising plans for affected affiliates for the years 2007 through 2009. The company responded that there were none.[36] Overland's review of PSE&G's direct mail and advertising copy did not reveal any advertising associated with DMC or Solar Source.[37]

PSE&G does not jointly employ employees of DMC or Solar Source.[38] PSE&G states that Human Resources tracks employee movement between PSE&G and affected affiliates. A review of employee transfers between PSE&G and affiliates revealed there were no transfers between the utility and affected affiliates during the period we requested (January 1, 2008 through October 31, 2009).

Prior Audit Recommendations

On March 31, 2003, Liberty Consulting submitted its final report to the BPU summarizing its Audit of the Competitive Service Offerings of PSE&G (Docket No. EA02020097). In this report, the auditor proposed twenty-four recommendations. Of the twenty-four recommendations proposed by the auditor, six

[30] Response to Discovery, OC-60, PSE&G 2009 Compliance Plan, p. 253 of 278
[31] Response to Discovery, OC-60, PSE&G 2009 Compliance Plan, p. 253 of 278
[32] Response to Discovery, OC-60, PSE&G 2009 Compliance Plan, p. 254 of 278
[33] Response to Discovery, OC-60, PSE&G 2009 Compliance Plan, p. 261 of 278
[34] Response to Discovery, OC-60, PSE&G 2009 Compliance Plan, p. 261 of 278
[35] Response to Discovery, OC-60, PSE&G 2009 Compliance Plan, p. 261 of 278
[36] Response to Discovery, OC-62
[37] Response to Discovery, OC-71
[38] Response to Discovery, OC-60, PSE&G 2009 Compliance Plan, p. 266 of 278

were characterized by either the BPU or the company as being contested at some point in time following the release of the prior auditor's report. The remaining eighteen recommendations were accepted by the company with limited exceptions.[39]

Overland reviewed the status of PSE&G's implementation of the recommendations made in the prior audit as reported by the company. Given the nature and/or continued applicability of the recommendations, our findings concerning their continued viability can be summarized as follows:

- Prior audit recommendations to amend or update the Compliance Plan. Several of the prior audit recommendations involved proposed modifications to the company's Compliance Plan. Our review indicated that wording consistent with the proposed changes was included in the 2009 Compliance Plan.[40] No additional company action to address these specific recommendations is necessary. (Prior Audit Recommendation Nos. 4, 5, 6, and 18)

- Prior audit recommendations to amend or update policies and procedures. The previous auditor recommended several specific improvements to company policies and procedures. The company agreed in principle with these recommendations. In some cases, the company did exactly as the prior auditor proposed, and we were able to verify that the changes had been adopted (e.g., changes to exit-interview procedures). However, in other cases, the company chose to pursue its own course of action to address a matter (e.g., information technology security). In these cases, whether or not the action taken successfully addressed the prior auditor's concerns was less clear. The company represented to us that the status of these matters was "complete." Major systems changes have occurred in the interim that may make some of the recommendations less relevant. (Prior Audit Recommendation Nos. 7 and 22)

- Prior audit recommendations concerning entities that no longer are affiliated with PSE&G. Some recommendations from the prior audit, both contested and uncontested, involved specific affiliate relationships that no longer exist. As a result, these recommendations are moot.[41,42,43] (Prior Audit Recommendation Nos. 1, 3, 10, 15, 20 and 23)

- Disputed audit recommendations superseded by subsequent BPU rules. In the prior audit, the auditor recommended the following:

[39] Prior audit report dated March 21, 2003, pp. 2-4 and response to Discovery, OC-46.
[40] Based on a review of the PSE&G July 1, 2009 Compliance Plan provided in response to Discovery, OC-60.
[41] However, to the extent that new affiliate relationships with similar attributes are initiated, the prior recommendations would need to be reexamined.
[42] Response to Discovery, OC-885 & OC-887.
[43] While Prior Audit Recommendation No. 23 is moot because PSEG ET was sold since the release of the previous audit report, PSE&G continues to take exception with interpretations of N.J.A.C. 14:5-5(q) that do not take into consideration the provisions of N.J.A.C. 14:5-5(i). See responses to Discovery, OC-46 (p. 10 of 28) and OC-887.

- Demonstrate the adequacy of steps to protect the utility from the negative effects of affiliation with unregulated businesses and the continuing sufficiency of utility spending. (Prior Audit Recommendation No. 24)

The auditor provided no specifics on how the company would implement such a proposal or how frequently the demonstration should occur. Furthermore, the auditor had no findings or conclusions suggesting that PSE&G's utility spending was inadequate or influenced by financial conditions attributable to non-utility operations.[44]

Although PSE&G agreed that periodic reporting to the BPU on its credit quality and service reliability had merit, they took exception with the implication that PSE&G's access to capital and financing costs had been negatively affected by its affiliation with the PSEG consolidated group of companies or that PSEG had or would decrease utility spending at the expense of safe, adequate, and reliable service.[45]

Subsequent to the release of the audit report, the BPU adopted Public Utility Holding Company rules that are codified in the New Jersey Administrative Code (NJAC) § 14:4-4A. These rules include restrictions on corporate investments in nonutility associates (less than 25 percent without BPU approval), restrictions on equity distributions to affiliates if the utility equity ratio falls below 30 percent, and requirements for the utility to file remedial action plans when its credit ratings or its parent's approach speculative grade.[46] In addition, the new rules include the following language:[47]

> *No public utility holding company system shall be operated in any way that materially impairs or could reasonably be expected to materially impair the electric or gas public utility's credit, ability to acquire capital on reasonable terms, or ability to provide safe, adequate and proper utility service at just and reasonable rates.*

PSEG's year-end investment in nonutility associates as filed with the BPU ranged from 0.9% to 2.7% between 2007 and 2009.[48] PSE&G's senior secured debt was recently rated A- by Standard & Poor's and A2 by Moody's,[49] both of which are several notches above the level at which the company is required to take remedial action.

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[44] Prior audit report dated March 21, 2003, p. 171.
[45] Response to Discovery, OC-46 pp. 16-17.
[46] NJAC § 14:4-4A.3, 14:4-4A.6, and 14:4-4A.7.
[47] NJAC § 14:4-4A.7(a).
[48] Response to Discovery, OC-327.
[49] Response to Discovery, OC-117.

Given the wide latitude afforded us in determining whether the prior auditor's concerns have been adequately addressed by the company, we find that the new BPU rules concerning public utility holding companies provide a reasonable framework for assessing whether nonutility businesses are having a significant negative impact on PSE&G. As such, we agree with the company that the prior audit recommendations have been effectively superseded by the new rules. Elsewhere in this report, we present an independent assessment of the impact that corporate nonutility investment has on PSE&G.

- <u>Prior audit recommendations that were contested (either formally or informally) and continue to remain outstanding.</u> The prior auditors and the company had different interpretations of EDECA and related standards. These differences in opinion were summarized in both the final audit report and subsequent comment letters filed by the company with the BPU. It is our understanding that no resolution to contested matters was ever reached even though they were eventually to return to the BPU agenda for further consideration. Of the six contested recommendations noted by the company, the BPU, or both; we note that most are no longer relevant as written because of changes in circumstances since the last audit report was issued. However, one recommendation that continues to remaining outstanding is:[50]

    - Reposition the duties of individuals who serve as a Director or an Officer for both the utility and a holding company related competitive business segment (RCBS) so that PSE&G is in compliance with the standard. (Prior Audit Recommendation No. 12)

  In addition, the status of another recommendation was pending BPU review as recently as July 2010, presumably because the company took a different stance from the prior auditor on what constituted a retail competitive service.[51] This recommendation is as follows:

    - Place into the PSE&G Compliance Plan an expanded concept of what constitutes a holding company RCBS. (Prior Audit Recommendation No. 2)

- <u>Prior audit recommendation concerning restrictions on affiliate employees that no longer apply.</u> The prior auditor was concerned about possible restrictions involving employees of RCBS of the holding company. According to the company, the two identified RCBS in the prior audit either no longer offer the services that subject their employees to potential restrictions or no longer are affiliates. As identified by the company, the two current RCBS do not provide the services in question. Consequently, the recommendation is currently moot.[52] (Prior Audit Recommendation No. 11)

[50] Prior audit report dated March 21, 2003, pp. 94-96 and 171 and response to Discovery, OC-887.
[51] Prior audit report dated March 21, 2003, pp. 5-15 and response to Discovery, OC-887.
[52] Prior audit report dated March 21, 2003, pp. 92-94 and response to Discovery, OC-885.

- Prior audit recommendation that the company be required to periodically examine the closeness of the relationship between total operating company procurement expenditures and procurement expenditures under master agreements and to assure periodic updating of the allocation factors applied. According to the company, all expenditures are subject to strategic sourcing reviews once every three years, with approximately one-third of expenditures being reviewed annually. PSE&G also represented that the Strategic Sourcing Group evaluated the cost drivers as the basis of allocating costs for Master Agreements.[53] The prior auditor did not specify how often an examination should be performed but indicated that annual reviews were not necessary. We believe the company's actions conform to the spirit of the recommendation. (Prior Audit Recommendation No. 8)

- Prior audit recommendation that Service Company practice areas eliminate the double counting of overhead. The company asserts that the practice of double counting overhead was eliminated beginning with the 2004 planning cycle.[54] Specific recommendations concerning current service company charges will be made elsewhere in this report. (Prior Audit Recommendation No. 9)

- Prior audit recommendation that PSE&G be reimbursed for transactions that did not conform to EDECA Standards . Specific examples identified by the prior auditor included recommendations:

    - to reimburse PSE&G for the time value of money for a payment due to PSE&G that an affiliate (Power) received in error (Prior Audit Recommendation No. 13)

    - to correct the computation of net book value of an asset transfer and to accrue interest on this miscalculation until payment is received. (Prior Audit Recommendation No. 14)

Power ultimately reimbursed PSE&G $163,000 (the amount recommended by the prior auditor) for the first item identified above in mid-2003.[55]

On June 13, 2003, PSE&G billed PSEG ET for $110,044 ($90,440 plus interest of $19,604) for the second item listed above. Interest was calculated through the end of May, 2003 at a rate of 10 percent. PSEG ET did not pay PSE&G until November 21, 2003.[56] Given the delay in paying the intercompany invoice, PSEG ET should have paid additional interest of at least $4,273 to

[53] Prior audit report dated March 21, 2003, p. 66 and response to Discovery, OC-885.
[54] Response to Discovery, OC-885.
[55] Response to Discovery, OC-1466.
[56] Response to Discovery, OC-1467. As a proxy for the correction of net book value, the prior auditor suggested the used of $90,440.

PSE&G.[57] If this unpaid balance was brought forward through the end of 2010, the amount outstanding would be over $8,300 (assuming a 10 percent rate).

Our evaluation of more recent transactions is documented elsewhere in this report. If the recommendations bear repeating, they will be made in the context of those discussions.

- Prior audit recommendation that the cost of capital and installment-sale balances be included when calculating the costs of the Appliance Service's competitive offerings. Judgmental testing of one appliance service filing made in 2009 indicated that the company had implemented the changes recommended by the prior auditor.[58] (Prior Audit Recommendation No. 16)

- Prior audit recommendations concerning interaction between company customer service professionals (CSPs) and customers regarding optional non-safety services.[59] The Compliance Plan filed with the BPU indicates that CSPs are trained and instructed to inform customers that competitive service offerings are optional and to refer them to the telephone directory for other service providers.[60] We were provided new CSP training materials that specifically discussed the appropriate handling of customer requests for competitive services.[61] Annual compliance training program materials also clearly state that PSE&G ". . . will not provide its customers with . . . responses to requests for assistance, information or advice about an Affected Affiliate."[62] Management also conducts five Customer Contact Evaluations per quarter for each CSP. One component of the Customer Contact Evaluation is compliance with policies and procedures.[63] According to the company, an internal audit conducted in 2006 showed that CSPs were complying with the prior auditor's recommendations concerning competitive services.[64] We believe the company's actions have addressed the prior auditor's concerns. (Prior Audit Recommendation Nos. 17 and 19)

- Prior audit recommendation to continue to monitor progress in implementing a recommendation made in the 2000 EDECA audit. This 11-year old recommendation concerned the company's use of "planned" expenditures in developing cost allocations. Overland's independent evaluation of this process is documented elsewhere in this report. To the extent

[57] Using the company's computation of monthly interest of $754, (754 x 5-2/3 months) = $4,273. This would compensate PSE&G for the months that the principal balance was outstanding in June, July, August, September, October, and a portion of November.
[58] Prior audit report dated March 21, 2003, p. 135 and response to Discovery, OC-885.
[59] Prior audit report dated March 21, 2003, pp. 109, 135-136, and 144-145.
[60] Response to Discovery, OC-60, p. 241 of 278.
[61] Response to Discovery, OC-1470, p. 14 of 72.
[62] Response to Discovery, OC-1470 and OC-750, p. 26 of 29.
[63] Response to Discovery, OC-1470, p. 70 of 72.
[64] Response to Discovery, OC-1470.

that the basis for this particular recommendation still remains valid, it has been integrated into our current findings and recommendations.[65] (Prior Audit Recommendation No. 21)

[65] Prior audit report dated March 21, 2003, p. 150 and response to Discovery, OC-885.

3. PSEG SERVICES CORPORATION

PSEG Services Corporation (PSEG Services or Service Corp) provides management and administrative services to PSEG's subsidiaries. Most activities which provide benefits common to PSE&G, the utility, and other non-regulated subsidiaries are maintained in the service company.

Scope, Objectives and Conclusion

Our analysis of PSEG Services and its cost distributions included the years 2007, 2008 and 2009. The table below summarizes cost distributions from PSEG Services to PSEG's key cost objectives, referred to as operating companies (OCs).[1]

Table 3-1 – Cost Distributions to Segments

PSEG Services Corporation Cost Distributions to Segments ($000s)						
	2007		2008		2009	
Segment	Amount	Pct	Amount	Pct	Amount	Pct
Enterprise	$289	0.1%	$161	0.0%	$388	0.1%
Holdings	20,248	5.0%	22,113	4.9%	15,604	3.7%
Pow er	143,735	35.7%	165,339	36.6%	155,978	37.5%
Utility	237,904	59.2%	264,125	58.5%	244,199	58.7%
Total	$402,176	100.0%	$451,738	100.0%	$416,169	100.0%

Our primary objective in reviewing PSEG Services was to determine that internal controls and accounting procedures were sufficient to prevent significant opportunities for cross-subsidization of non-regulated operations through overcharging of service company costs to the Utility OC.

Summary of Findings

1. Internal Controls and Procedures - Control over service company budgeting, accounting and cost distributions during the review period (2007 through 2009) was adequate to inhibit significant opportunities for cross-subsidization of non-regulated Power and Holdings operations by PSE&G. Specifically:

    - The operating companies, including Utility, participate in the annual service company planning and budgeting process. This provides the operating companies the opportunity to provide input into the level and cost of services billed to them by the service company.

[1] Response to Discovery, OC-554

- In most cases, services are designed to measure and track the cost of activities. Activity-based costing facilitates the proper assignment of cost to cost-objectives and is an important component of an attribution-based cost distribution process.

- Services are segregated by degree of control to provide the operating companies and lines of business the ability to scale service levels to their needs.

- In most cases, pricing methods appear to establish causal links between the activities performed by the service company and the OCs receiving the services.

- Service prices are designed to recover costs on a fully-distributed basis, meaning that the prices included applicable labor loadings and service company overheads and are designed to recover, as a group, all incurred service company costs.

- The percentage of costs distributed using "unattributable" size-based allocators (Enterprise costs) is relatively low and appears to be decreasing as refinements in the analysis and pricing of services continues.

2. Changes in Enterprise Cost Allocation Methods - In 2009 the service company reduced the number of methods used to distribute Enterprise costs (costs incurred on behalf of the corporation as a whole) from four to one. Specifically, "modified Massachusetts", "revenue-earnings-capX", "headcount" and "Law department historical experience" allocation methods were replaced by a single consolidated method that allocates costs based on a composite of net fixed assets, headcount and O&M expense. The change had little impact on the percentage of Enterprise costs allocated to the Utility and Power OCs (PSE&G's share of Enterprise costs increased from 55.3 percent in 2008 to 56.0 percent in 2009). However, the increased importance of headcount and assets under the new method, both of which are lacking in the Holdings OC, cut allocations to Holdings by more than half. Specifically, Holdings' share of Enterprise costs decreased from 2.3 percent in 2008 to 1.0 percent in 2009, and Enterprise costs allocated to Holdings decreased from $1.6 million in 2008 to $688,000 in 2009.

3. Reductions in the Enterprise Cost Pool / Reductions in Costs Allocated to Holdings – 2008 cost reclassifications reduced the percentage of costs classified as unattributable Enterprise costs. Specifically, the percentage of service company costs included in the Enterprise cost pool decreased from $81.0 million (20 percent of service company charges) in 2007 to $72.4 million (16 percent of service company charges) in 2008.[2] In percentage terms, the Holdings OC was by far the largest beneficiary of the change. Allocations of Enterprise costs to Holdings dropped from $3.6 million in 2007 to $1.6 million in 2008.

4. Incurred Service Company Costs - Service company costs did not increase significantly during the review period. Costs were $402 million in 2007 and $416 million in 2009. A higher level of cost in 2008 ($451 million) can be attributed primarily to costs incurred to implement PSE&G's new iPower

[2] In 2009, Enterprise costs were $69.1 million (17 percent of service company charges).

(customer service) system. 2009 was lower due primarily to completion of the new customer service system and the transfer of approximately $21 million in Environmental, Health and Safety services out of the service company.

5. Refinements and Changes in Pricing and Cost Allocation Procedures – PSEG Services made various changes in pricing and allocation procedures during the audit period. A number of these are included in the discussion of PAs and services below. They had a relatively minor impact on the distribution of service company costs between 2007 and 2009. The percentage of costs charged to PSE&G remained steady at approximately 59 percent. Costs billed to the Power OC increased from 35.7 percent to 37.5 percent. The Holdings OC was the largest beneficiary of the changes made between 2007 and 2009. Charges to Holdings dropped by about one-fourth, from $20.2 million to $15.6 million, despite a small increase in total costs billed. Changes associated with certain functions and services are discussed below. When viewed from the perspective of total distributed cost, and in the context of the procedures and controls in place, we do not believe the changes and refinements made during the review period are a cause for concern.

Recommendations

1. Whenever possible, costs from the service company's Internal Audit professional services should be directly charged based on the "clients" for whom audits are performed. Although professional internal audit services appear to be charged at an hourly rate as a professional service, the distribution of audit services among operating companies from year to year during the review period was virtually identical (e.g. 53% Utility in 2007, 55% Utility in 2008 and 56% Utility in 2009) and very close to the Enterprise allocator, suggesting that a type of size-based allocation factor is driving the charges. It is appropriate to charge "corporate" audits benefiting the corporation as a whole using a size-based factor such as the Enterprise allocator. However, many audits are performed specifically for the benefit of particular operating companies and segments. Time should be charged to each audit, and the cost of the audit should be billed to the appropriate operating company "client," just as it would if it were provided by an outside professional service provider.

Service Company Organization and Services

For purposes of service budgeting, pricing and billing, PSEG Services is divided into functional groups called practice areas (PAs). In general, PAs correspond with the management organization and budgetary cost centers.[3] The table below summarizes costs incurred by PA during the audit period.

[3] With a few exceptions, each PA corresponds with a cost center. Exceptions include Information Technology, which had separate cost centers for "products" and client "projects," and Treasury Management Services, which also had two cost centers.

Table 3-2 – Costs Incurred by Practice Area

PSEG Services Corporation Costs Incurred By Practice Area ($000s)			
Practice Area	2007	2008	2009
Accounting Svcs	$32,298	$29,280	$28,446
Business Center	28,930	23,732	23,085
Claims	3,972	4,148	4,153
Comm & Advertising	13,581	13,396	10,511
Corp Development	1,221	4,837	2,505
Corp Security & Claims Total	10,018	8,441	6,937
Corp Secretary	1,388	1,463	1,440
Corporate Strategy	5,121	4,407	5,655
Environmental, Health Safety	45,632	42,445	21,035
Enterprise Risk Mgt	4,211	4,143	4,529
Fed Affairs & Policy	1,481	3,230	3,367
Finance	1,808	24,359	27,383
Human Resources	19,703	24,946	22,026
Information Technology	155,430	176,711	151,532
Internal Audit	6,649	5,355	3,677
Law	22,772	27,521	23,307
PSEG Executive Office	20,841	21,563	29,767
Records & Library	1,334	2,516	2,092
State Government Affairs	1,629	2,855	4,535
Supply Chain Management	11,188	13,466	14,878
Treasury Management Svcs	12,873	12,927	10,860
ServCorp Misc Accting & Other	94	1	14,453
ServCorp Total	$402,177	$451,738	$416,170
Source: OC-554			

Overview of Services by Practice Area

PAs are divided into services. Services are designed around activities and types of cost. Operating company (OC) service levels and pricing are planned and calculated at the service level.

Accounting Services – Accounting Services consists of four areas: financial systems support, corporate accounting and reporting, tax and Sarbanes Oxley (Sarbox) compliance.

- Financial Systems Support (Service ID 1001) – This is a Basic Business service that includes maintenance of SAP, Hyperion and related accounting systems. On-going support is based on the Enterprise allocation method. Special projects or enhancements attributable to a specific OC are billed directly to the OCs. As a result of direct assignments to Power and Holdings, this resulted in a distribution to the Utility OC of 54% in 2009, somewhat lower than the overall Utility Enterprise allocation of 59% in 2009.

- Corporate Accounting & Reporting (Service IDs 1003, 1004, 1005, 1009, 1012, 1596, 1597) - This includes external audit fees, other outside services and internal labor relating to maintaining corporate and subsidiary books, internal labor for the closing and maintenance of the corporate books, maintenance of subsidiary books, SEC reporting and the preparation of financial materials for the board of directors. Depending on the service, costs are allocated using the Enterprise allocation method (corporate audit fees, corporate books maintenance, SEC reporting), passed through to appropriate clients (certain outside services), or billed based on hours worked on a subsidiary's books (maintaining multiple subsidiary books). Maintenance of subsidiary books "above the margin line" is considered either a Power or Utility-dedicated, Limited Control service and billed directly to the appropriate OC. Maintenance of books "below the margin line" (work on administrative and general accounts, for example), is considered a Basic Business service, but is also charged to specific subsidiaries based on hours worked.

- Tax Services (Service IDs 1007, 1013, 1014, 1015) – The Tax PA includes internally-provided and outside tax and related legal services. Services 1007, 1013 and 1015 consist of outside services and internal labor for federal and state tax filings applicable to specific subsidiaries, classified as "Basic Business" and directly billed. Outside services provided to the Utility OC include "a variety of state and local tax issues and projects" and Uniform Capitalization Rules Implementation. Outside services provided to the Global segment include "a variety of international tax planning, accounting and compliance issues."[4] Outside services provided to PSE&G increased significantly in 2008, to $968,000, from $280,000 in 2007. The company indicates this was due to a project concerning Uniform Capitalization Rules.[5] In the same period, outside services provided to the Holdings OC declined significantly, from $3.4 million in 2007 to $922,000 in 2008. The company states that this was due to the transfer of responsibility for Global tax consulting from the service company to the companies in the Holdings OC.[6] Service 1014 consists of internal labor for tax services benefiting the corporation as a whole, allocated using the Enterprise method.

- Sarbanes Oxley Compliance (Service IDs 1453, 1653, 1655) – Sarbox services consists of internal labor and outside audit services relating to Sarbox compliance efforts. Services for specific subsidiaries are directly billed; services on behalf of the corporation are allocated using the Enterprise method.

Accounting Services cost distributions among OCs are summarized below. The total cost of the services declined by 10 percent from 2007 to 2009, due primarily to the transfer of budget responsibility for consulting services to the businesses within Holdings (as discussed above). During the same period charges to PSE&G increased by about 6 percent. The company attributes this to an increase in external audit fees, "refinement of the use of the Enterprise methodology" and employee salary increases.[7]

[4] Response to Discovery, OC-1211-A & B.
[5] Response to Discovery, OC-1211-D.
[6] Response to Discovery, OC-1211-C.
[7] Response to Discovery, OC-1342.

Table 3-3 – Cost Distributions - Accounting Services

PSEG Services Cost Distr butions Accounting Services ($000s)						
Segment	2007		2008		2009	
	Amount	Pct	Amount	Pct	Amount	Pct
Enterprise						
Holdings	9,831	30%	6,314	22%	4,708	17%
Pow er	11,925	37%	11,764	40%	12,612	44%
Utility	10,542	33%	11,202	38%	11,126	39%
Total	$32,298	100%	$29,280	100%	$28,446	100%
Source: OC-554						

Business Center – The Business Center PA includes a variety of administrative services. Most are classified as High Control, over which client subsidiaries have direct control of service demand, or as Basic Business services. Most are directly billed.

- Accounts Payable (Service IDs 1017, 1021, 1023, 1336) - Accounts Payable includes the processing of purchase orders, automated and manual invoices (separate service IDs for each) and internal labor to meet specific needs and for initiatives and system upgrades. Invoice processing is High Control and is directly billed on a per-invoice basis (with different rates for each type of invoice). Internal labor attributable to specific OCs is directly billed at an hourly rate.

- Payroll, Benefits and Pension Administration, Expense Reimbursement and Travel (Service IDs 1018, 1022, 1024, 1025, 1026, 1032, 1859) consist primarily of internal labor to process and audit employee expense reports (Service 1022), process employee time reporting and pay deductions (Service 1025), process other payroll-related requests and off-cycle pay checks (Service IDs 1018 and 1859), respond to payroll, pension and employee benefits inquiries and conduct related research (Service IDs 1024 and 1026), and provide travel reservations (Service 1032). These are classified as either Limited Control or Basic Business services; however, employee expense reimbursement (Service ID 1022) is a High Control, Transactional service, billed on the basis of expense forms processed.

- Corporate Headquarters (Service IDs 1034, 1035, 1036, 1037) – This includes the rent, other building costs and the cost of managing the PSEG corporate headquarters building in Newark that houses service company and some operating company employees. It also includes motor pool rental costs and permit parking management for the Mulberry St. garage. Most of the cost in this group, and over half of the cost of the entire Business Center category, consists of ID 1036 – Corporate Headquarters Services, a Basic Business service billed to OCs and the service company on the basis of occupied square footage.

- Mail and Copy (Service IDs 1029, 1040, 1041, 1042, 1858) – This service group includes copy services (Service IDs 1040 and 1041) and mail services (Service IDs 1029 and 1858), which include postage and mail delivery services. Copy services are billed directly based on copy volumes. Postage is either passed through to clients, or, if clients are not identified, it is allocated based on the Enterprise methodology. Mail services are "billed based on analysis of specific mail routes supported."

Business Center cost distributions among OCs are summarized below.

Table 3-4 – Cost Distributions - Business Center

PSEG Services Cost Distr butions Business Center ($000s)						
Segment	2007		2008		2009	
	Amount	Pct	Amount	Pct	Amount	Pct
Enterprise	-					
Holdings	1,904	7%	971	4%	944	4%
Pow er	8,646	30%	5,987	25%	5,749	25%
Utility	18,381	64%	16,775	71%	16,391	71%
Total	$28,930	100%	$23,732	100%	$23,085	100%
Source: OC-554						

The decline in cost between 2007 and 2009 is due primarily to the following:

- Removal of service 1043 – Manage Shareholder Services, which incurred and distributed $3 million in 2007 (primarily to Utility and Power), but was not provided in 2008 or 2009.
- A $2 million decrease of in square-footage based charges. This resulted in a $1 million (22 percent) savings for Power, a $873,000 (57 percent) savings for Holdings and a $108,000 (1 percent) savings for Utility. It appears that the costs removed were redistributed to the service company overhead pool.

Claims (Service ID 1045) – The Claims PA consists of internal labor providing claim processing and management. As shown in the table, costs are directly billed primarily to PSE&G. Billing is based on an hourly rate.

Table 3-5 – Cost Distributions - Claims

PSEG Services Cost Distr butions Claims ($000s)						
Segment	2007		2008		2009	
	Amount	Pct	Amount	Pct	Amount	Pct
Enterprise	-				-	0%
Holdings	1	0%	0	0%	0	0%
Pow er	4	0%	6	0%	6	0%
Utility	3,967	100%	4,142	100%	4,146	100%
Total	$3,972	100%	$4,148	100%	$4,153	100%
Source: OC-554						

Communications and Advertising – This PA includes advertising, branding and related services provided to PSE&G, Power and Holdings OCs and the corporation as a whole. It also includes communications consulting, external communications and web services.

- Advertising and Branding (Service IDs 1049, 1059, 1062, 1072, 1073, 1074) – This includes charges by outside service providers for media and promotions. A small amount is high control, directly billed, but most is considered to benefit the corporation as a whole and is allocated using the Enterprise allocation method. Individual service IDs separate outside services from internal labor and corporate from operating company-specific charges.

- External Communications (Service IDs 1050, 1052,1067, 1070 – External communications includes press relations, speechwriting, external event coordination and executive support. Separate service IDs allow these functions to separately account for operating company (directly billed, high control) and corporate (enterprise, allocated) services and for outside services and internal professional services.

- Communications Consulting (Service IDs 1058, 1063, 1081, 1082) – This service group includes implementing internal communications plans of the operating companies and PSEG at the corporate level. Separate service IDs allow these functions to separately account for operating company (directly billed, high control) and corporate (enterprise, allocated) services and for outside services and internal professional services.

- Internal Communications – (Service ID 1065) – This service includes the costs of PSEG's internal publications (PSEG Outlook (monthly), Outlook Online and Outlook This Morning (daily). It is classified as a Basic Business Service and consists of internal labor and outside services allocated to operating companies based on combined employee and retiree headcount.

- Web Services (Service IDs 1867, 1868, 1869) – This is a new service classification in 2009. The costs budgeted in 2009 were not actually incurred. Web services include the development and execution of internet / intranet communications. Separate service IDs allow these functions to separately account for operating company (directly billed, high control), corporate (enterprise, allocated) and for outside and internally provided services.

The table below summarizes Communications and Advertising PA cost distributions.

Table 3-6 – Cost Distributions - Communications & Advertising

PSEG Services Cost Distr butions Communications & Advertising ($000)						
Segment	2007		2008		2009	
	Amount	Pct	Amount	Pct	Amount	Pct
Enterprise	-					
Holdings	346	1%	602	4%	20	0%
Pow er	6,963	51%	6,604	49%	4,752	45%
Utility	6,273	46%	6,190	46%	5,739	55%
Total	$13,581	100%	$13,396	100%	$10,511	100%
Source: OC-554						

Corporate Development (Service IDs 1803, 1804,1807) - The Corporate Development PA can be viewed as a part of the Corporate Planning area. It is described as "development, pursuit and execution of . . . growth opportunities for the overall Enterprise." One of the primary activities is research into potential acquisitions. Services 1803 and 1804 comprise about 75 percent of the PA's spending and consist of internal labor and outside services directly billed to operating companies. Service 1807 consists of activities provided on behalf of the corporation, consisting primarily of internal labor, which are retained by PSEG, rather than allocated to the operating companies. Service 1915 was new in 2009 is attached to the Holdings OC, Global President's office. It contains no budget amount and is not described in the Service Catalog. As shown below, PSE&G was not charged a significant amount of Corporate Development costs during the audit period.

Table 3-7 – Cost Distributions - Corporate Development

PSEG Services Cost Distr butions Corporate Development ($000s)						
Segment	2007		2008		2009	
	Amount	Pct	Amount	Pct	Amount	Pct
Enterprise	$150	12%	$9	0%	$369	15%
Holdings	227	19%	2,477	51%	1,066	43%
Pow er	843	69%	2,343	48%	1,046	42%
Utility		0%	7	0%	24	1%
Total	$1,221	100%	$4,837	100%	$2,505	100%
Source: OC-554						

Corporate Planning – The Planning PA includes budgeting, business and strategic planning. Individual services reflect different components of the corporate planning process, as follows:

- Strategic Planning (Service IDs 1086 and 1096) – Service 1086 consists of leading the strategic and business planning process for the enterprise and oversees the preparation of the five-year corporate plan, allocated using the Enterprise methodology. It consists primarily of internal labor allocated using the Enterprise method. Service 1096 is a "passthrough" service consisting of special studies "on long range or strategic issues."[8] Although the billing methodology allows for direct billing of "specific initiatives" to the operating companies, the entire cost of service 1096 was allocated using the Enterprise method in all three years reviewed. Given that "strategic" issues are often associated with the competitive components of the business, the allocation of more than half (beginning in 2009) of the costs of service 1096 to PSE&G may be questionable, depending on the nature of the services provided. However, the total amount involved is relatively small, averaging about $640,000 annually during the review period, of which approximately $320,000 annually was allocated to PSE&G.

- Financial Planning and Analysis (Service ID 1087) – This service leads the corporate-level five-year business planning process. It includes long-term financial forecasting for the corporation and the preparation of cost of capital and valuation studies. It consists primarily of internal labor allocated using the Enterprise method.

- Enterprise Budgeting (Service ID 1088) – This service leads the corporate budgeting process. It consists mainly of internal labor, allocated using the Enterprise method.

- Business and Competitive Assessment (Service ID 1089) – This service consists of assessing PSEG's competitive markets. Among its responsibilities are compiling data on market growth and share and analyzing industry activities and trends. It consists primarily of internal labor allocated using the Enterprise method. The job descriptions for the two employees providing this service indicate that the service involves competitive market "intelligence" and "business opportunities,"[9] suggesting that the benefits may flow mainly to the non-regulated, competitive Power and Holdings OCs. However, under the Enterprise allocation methodology, currently more than half of the total cost of the function flows to the Utility OC. This raises a question about the reasonableness of the allocation; however, the amounts involved (about $470,000 annually before allocation) are not significant in the context of total service company charges.

- Emergent Technology and Transfer (Service IDs 1874 and 1875) – Services provided through ID 1875 manage corporate R&D with the Electric Power Research Institute "to extract business value for operations." They consist primarily of internal labor billed on a project basis to specific clients (high control, directly billed). Service ID 1874 includes of "specific projects or studies" passed through to clients requesting the project. In 2008 and 2009, the two years for which this service ID shows activity, approximately 95 percent of the amounts expended ($437,000 in 2008 and $1,459,000 in 2009) were charged to PSE&G. The company indicated that the function was part of the Utility until August, 2008, and was moved into the service company.[10] It appears that the occasional service provided to the Power OC warrants the inclusion of this function in the service company.

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[8] Response to Discovery, OC-1094, PSEG Services 2009 Service Catalog, p.72.
[9] Response to Discovery, OC-1349.
[10] Response to Discovery, OC-1348.

Audit period cost distributions for Corporate Planning are summarized below.

Table 3-8 – Cost Distributions - Corporate Planning

PSEG Services Cost Distr butions Corporate Planning ($000s)						
Segment	2007		2008		2009	
	Amount	Pct	Amount	Pct	Amount	Pct
Enterprise	-					
Holdings	148	3%	54	1%	42	1%
Pow er	2,004	39%	1,547	35%	1,855	33%
Utility	2,969	58%	2,807	64%	3,758	66%
Total	$5,121	100%	$4,407	100%	$5,655	100%
Source: OC-554						

Corporate Secretary (Service IDs 1097, 1098) – Services provided by the Secretary PA are described as resources supporting the boards of directors of the corporation and subsidiaries. Service ID 1097 consists of internal labor used to coordinate board meetings, compile and disseminate information, produce governance documents and conduct research. Service ID 1098 consists of external resources associated with the annual stockholders meeting, such as rental of the New Jersey Performing Arts Center, where the meeting is held, and the cost of materials used at the meeting. Corporate Secretary services are allocated using the Enterprise methodology. Audit period cost distributions are summarized below.

Table 3-9 – Cost Distributions - Corporate Secretary

PSEG Services Cost Distr butions Corporate Secretary ($000)						
Segment	2007		2008		2009	
	Amount	Pct	Amount	Pct	Amount	Pct
Enterprise	-					
Holdings	44	3%	29	2%	14	1%
Pow er	747	54%	834	57%	619	43%
Utility	597	43%	600	41%	806	56%
Total	$1,388	100%	$1,463	100%	$1,440	100%
Source: OC-554						

Corporate Security – This PA includes corporate guard service, business interruption management, security planning and operations and the security command center. Billing procedures were significantly revamped in 2009 coincident with significant reductions in expense. Changes in cost distribution procedures increased PSE&G's share of total cost from 61 percent to 78 percent, while the share of costs charged to Power and Holdings was cut almost in half. Thus, although the changes in procedures made the cost distributions more direct, the Utility share of total costs increased.

Prior to 2009, most security activities other than guard services were accounted for under Corporate Security service 1099. Service 1099 was considered attributable to the corporation as a whole and was allocated using the Enterprise method. In 2009, the overall cost for these activities was reduced from $6.7 million to $4.7 million and broken into three new services: Business Interruption Management, Security Command Center and Security Planning and Operations. Two of these, Security Command Center and Security Planning and Operations, which as part of service 1099 had been allocated using the Enterprise allocation method, were distributed in 2009 using a percentage closely related to the number of cameras used to secure Utility and Power facilities. Because most of the cameras are installed at Utility facilities, this increased the Utility share of command center, planning and operating costs from about 60 percent in 2008 to approximately 83 percent in 2009. Cost reductions offset most of the impact of the increased allocation percentage, and total Utility costs increased only slightly. As shown in the table below, the beneficiaries of the changes made in 2009 were the Power and Holdings OCs which realized the benefits of lower total security costs, as well as significantly lower allocation percentages. Security services for 2009 included the following:

- Corporate Security Guard Service (Service ID 1853) – Guard service is classified as a Basic Business service, and is allocated based on occupied square footage. Approximately 70 percent is allocated to PSEG.

- Security Command Center (Service ID 1876) – As discussed above, this service breakout is new in 2009. It includes the functions of monitoring, recording and reporting security events using cameras and access control devices such card readers and ID badges, contracted to an outside vendor. Prior to 2009, command center costs were part of the Corporate Security service ID and were allocated using the Enterprise methodology. It is classified as a Basic Business service and allocated based on the number of devices (cameras) managed by the center. Based on this procedure, in 2009 approximately 92 percent was allocated to the Utility OC, and 8 percent to Power.

- Security Planning and Operations (Service ID 1886 and 1888) – Planning and operations is also a new service breakout for 2009. Service ID 1886 includes costs considered to benefit the corporation as a whole and is allocated using the Enterprise allocation method. Service ID 1888 includes a majority of 2009 security planning and operations costs. It is classified as a Basic Business Service and is billed to each operating company based on budgeted hours. The relative number of hours budgeted to operating companies in 2009 (89 percent Utility, 11 percent Power), appears to be closely related to the number of “devices” (cameras), (92 percent Utility, 8 percent Power) used to distribute the costs of the Security Command Center (discussed above). It is not clear from the service catalog how the security planning / operations function is divided between services benefiting the corporation as a whole (about $1 million in 2009, allocated using the Enterprise method) and services benefiting the OCs ($2.4 million in 2008, 89 percent charged to Utility). The process change that resulted in distributing OC-specific security planning and operations with a percentage closely related to the relative number of cameras, instead of using the Enterprise method (used prior to 2009), resulted in the redistribution of approximately $686,000 from Power and Holdings to PSE&G in 2009.[11]

- Business Interruption Management (Service IDs 1887, 1889) – This service is also new in 2009. It includes business continuity planning, crisis management, life safety and evacuation, emergency response and disaster recovery services. A majority of these costs are associated with service ID 1887, which is allocated using the Enterprise allocation method. Service ID 1889 is reserved for service that can be directly attributed to specific operating companies. It is a Professional / Basic Business Service and is billed based on budgeted hours. Approximately 70 percent of Service ID 1889 was charged to PSE&G in 2009. To the extent similar services were embedded in service 1099 – Corporate Security prior to 2009, approximately 60 percent was allocated to Utility under the Enterprise method.

As shown in the table below, as a result of changes discussed above, Corporate Security costs declined significantly (31 percent) during the audit period, but charges to PSE&G declined much less (8.5 percent).

Table 3-10 – Cost Distributions - Corporate Security

PSEG Services Cost Distr butions Corporate Security ($000)						
Segment	2007		2008		2009	
	Amount	Pct	Amount	Pct	Amount	Pct
Enterprise	-					
Holdings	401	4%	232	3%	72	1%
Pow er	3,722	37%	3,094	37%	1,471	21%
Utility	5,895	59%	5,115	61%	5,394	78%
Total	$10,018	100%	$8,441	100%	$6,937	100%
Source: OC-554						

Enterprise Risk Management – includes measuring and monitoring risk on behalf of the corporation as a whole; credit, confirmation and pricing performed for the Energy Resources and Trading unit, and management internal control services required by Sarbanes Oxley. A majority of these costs are charged to the Power OC, and within Power, a large percentage is charged to Energy Resources and Trading line of business.

- Independent Risk Oversight (Service IDs 1809, 1833, 1862, 1863) – This group of services includes identifying, measuring and monitoring risk exposure and compliance with risk management policies and procedures. Service 1809 consists primarily of internal labor. It is a Basic Business service, directly billed based on hours charged to each operating company. Services 1833 and 1862 consist of outside services for specific risk management deliverables, either for specific clients (High Control) or on behalf of the corporation as a whole (Professional / allocated using the

[11] $2,365,000 times (89% - 60%) equals $685,850. $2,365,000 is the amount spent on service 1888 in 2009. 89% is the Utility installed-camera-related factor for 2009. 60% is the Utility Enterprise Factor used to allocate these costs in 2008.

Enterprise allocation method). Service 1863 consists of independent risk oversight activities on behalf of the corporation as a whole. These include risk management board committee meetings, SEC filings and board meeting presentation materials, allocated using the Enterprise method.

- Sarbanes Oxley 404 (Service ID 1855) – This service includes activities associated with management's assessment of internal controls. It consists of internal labor. It is a High Control service, directly billed to operating companies based on hours worked.

- Credit, Confirmation and Pricing (Service IDs 1864, 1865) – Service 1865 consists primarily of internal labor and includes activities relating to Energy Resources and Trading, such as confirming transactions, updating independent pricing data, monitoring trading compliance and conducting counterparty credit reviews. Service 1864 consists of outside services for deliverables relating to these activities. Both are High Control services, directly billed to Energy Resources and Trading.

Audit period cost distributions are summarized below. In 2007, about one-fourth of total service cost in this PA was allocated using an Enterprise methodology, resulting in a relatively higher-level of allocations to the Utility. The process of classifying and billing services was re-worked in 2008, reducing the services charged using the Enterprise allocator, and reducing cost distributions to PSE&G. In addition, Sarbanes Oxley services, which continue to be allocated using the Enterprise method, incurred no cost in 2009, further reducing 2009 distributions to the Utility OC.

Table 3-11 – Cost Distributions - Enterprise Risk Management

PSEG Services Cost Distr butions Enterprise Risk Management ($000s)						
Segment	2007		2008		2009	
	Amount	Pct	Amount	Pct	Amount	Pct
Enterprise	-					
Holdings	198	5%	232	6%	57	1%
Pow er	3,142	75%	3,758	91%	4,173	92%
Utility	871	21%	153	4%	300	7%
Total	$4,211	100%	$4,143	100%	$4,529	100%
Source: OC-554						

Environmental, Health and Safety (EH&S) – EH&S includes environmental remediation, licensing, permitting and technical services, resource recovery, environmental strategy, policy and corporate image management, corporate health and safety and environmental compliance auditing. Costs in this PA declined significantly between 2008 and 2009 as a number of employees were transferred. Following are the services that remained in 2009.

- Remediation (Service IDs 1103, 1104, 1108, 1110, 1122, 1128) – Services 1103 and 1122 consist of salaries and third party invoices, respectively, for the investigation, analysis and management of manufactured gas plant remediation, directly billed to Utility Gas Distribution. Services 1104, 1108, 1110 and 1128 manage general remediation activities, prepare action work plans, develop specifications for and oversight of soil and ground water remediation, and conduct investigations. Individual service IDs separate the services between capital and expense and between internal labor and outside expenses, charged "directly to the operating company who requests the work." Remediation services are classified as Limited Control.

- Licensing, Permitting and Technical Services (Service IDs 1105, 1106, 1109, 1118, 1125, 1126, 1129, 1135) – Services 1109, 1118, 1129 and 1135 are Limited Control services that provide air, water, land use, operating and construction permits and approvals, "perform regulatory assessments", and provide due diligence, regulatory approval planning and expert witness testimonies, all billed "to the operating company who requests the work." Services 1105, 1106, 1125 and 1126 are Limited Control services that manage and implement New Jersey Pollutant Discharge Elimination System permitting requirements for the Salem Nuclear Plant, directly charged to Power Nuclear. Within each of these two groups of services, individual service IDs separate internal labor from outside services, and operating expense from capitalized amounts.

- Policy, Strategy and Image Management (Service IDs 1107, 1115, 1119, 1127, 1132, 1138) – Service IDs 1107 and 1127, Corporate Environmental Support and Image Management, include outside services and internal labor to develop and implement corporate environmental policy "necessary to preserve and protect shareholder value" and to "influence / shape the development of environmental regulations to the clients' advantage." This service is allocated using the Enterprise methodology. Service IDs 1115 and 1132, Environmental Strategy, consist of outside services and internal labor to "create policies and provide . . . information on how changing environmental laws / regulations may affect the business." This is a Limited Control service billed to "the Operating Company who requests the work." Service IDs 1119 and 1138, Environmental Policy and Regulatory Support, include providing advice and information on compliance with laws and how changing regulations may affect the business. It is also a Limited Control service and directly billed.

- Health and Safety Improvement (Service IDs 1116, 1117, 1133, 1134) – Service IDs 1116 and 1133 consists of outside expenses and internal labor to support the Health and Safety management system, provide industrial safety consulting, industrial hygiene testing and reporting and health and safety records management. These are Limited Control services billed directly "to the operating company who requests the work." Service IDs 1117 and 1134 include outside services and internal labor performing the same service, but on behalf of the corporation as a whole, allocated using the Enterprise methodology.

- Compliance Auditing (Service IDs 1120, 1137, 1898, 1899) – Service IDs 1120 and 1137 are outside services and internal labor to conduct the EH&S compliance audit program, develop the compliance program, measure performance and conduct special investigations. The service is considered corporate and is billed based on the Enterprise allocation method. Service IDs 1898 and 1899 were established with a similar purpose, but do not appear to have been used during the 2007-2009 audit period.

- Resource Recovery (Service IDs 1834, 1835, 1836, 1837) – The Resource Recovery category was new in 2008. Service ID 1834 consists of outside services expenses for "sustainability initiatives and PSEG facility energy audits." Service ID 1835 consists of outside costs associated with vehicle sales. Service IDs 1836 (expense) and 1837 (capital) consist primarily of internal labor incurred to manage hazardous waste, solid waste and coal ash. It also includes TSCA and PCB compliance services, waste reporting and accounting, sustainability and energy conservation services. Resource Recovery are Limited Control services directly billed "to the operating company who requests the work." About 70 percent of the cost is charged to PSE&G, with the remaining 30 percent charged to Power.

- Global EH&S (Service IDs 1806 and 1839) – New in 2008, this is described as "a full range of environmental health and safety service support specifically to Global." It is classified Basic Business service. Service ID 1806 consists of internal labor and ID 1839 consists of outside expenses. It makes up most of the cost charged to Holdings. It accounted for 2 percent of total EH&S cost in 2008, but only 2/10ths of 1 percent of total EH&S in 2009.

As shown below, service company EH&S costs declined more than 50 percent during the audit period.

Table 3-12 - Cost Distributions - Environmental, Health & Safety

PSEG Services Cost Distr butions Environmental, Health & Safety ($000)						
Segment	2007		2008		2009	
	Amount	Pct	Amount	Pct	Amount	Pct
Enterprise	-					
Holdings	362	1%	674	2%	424	2%
Pow er	24,999	55%	22,205	52%	9,676	46%
Utility	20,272	44%	19,566	46%	10,935	52%
Total	$45,632	100%	$42,445	100%	$21,035	100%
Source: OC-554						

When we asked PSEG to explain the 50 percent decline in cost in 2009, the company provided a three-sentence response stating that EH&S billings were reduced because 113 employees in the Maplewood Testing Service function (MTS) were transferred from the service company to the Fossil line of business within the Power OC. However, as shown below, we found a whole series of EH&S services, totaling more than $23 million in 2008, including some with significant charges PSE&G and to the Nuclear line of business within Power, disappeared from the service company between 2008 and 2009. Thus, employee transfers to the Fossil line of business do not appear to provide a complete picture of the changes that occurred. In fact, as shown in the table below, 2008 cost distributions to the Fossil business explain only about a third of the costs that disappeared in 2009.

Table 3-13 – Service Company Environmental, Health and Safety Services

PSEG Services Service Company Environmental, Health and Safety Services Provided in 2008, No Longer Provided in 2009 ($000s)					
Svc ID	Service	Utility	Power - Fossil	Power - Nuclear & Other	Total 2008 Actual Dollars
1280	MS-P-Photo Digital Imag Video Grp	$90	$29	$170	$289
1282	MS-P-Pow er Systems Reliability Group	1,896	555	511	2,962
1284	MS-P-Environmental Emissions Group	47	2,233	40	2,320
1285	MS-P-Thermal Performance Group	30	383	381	794
1286	MS-P-Nondestructive Examination Group	156	723	510	1,389
1287	MS-P-Metallurgy and Corrosion Group	43	597	370	1,010
1288	MS-P-Elec Sys Prot Tel and Cont Grp	1,493	737	176	2,406
1289	MS-P-V bration Analysis Group	14	976	285	1,275
1290	MS-P-Material Test and Inspection Grp	2,628	151	6	2,785
1291	MS-P-Analytical Chemistry Group	14	548	263	825
1292	MS-P-Insul Fluids and Petro Prods Grp	1,148	211	511	1,870
1293	MS-P-Radio Enviro Analysis Group			704	704
1294	MS-P-PT-Photo Digital Imag Video Grp	401	32	56	489
1297	MS-P-PT-Elec Sys Prot Tel and Cont Grp	34	191	6	231
1299	MS-P-PT-Material Test and Inspection Grp	410	15	1	426
1300	MS-P-PT-Environmental Emissions Group	22	480	8	510
1317	MS-P-PT-Metrology and Instrum Svcs Grp	223	3		226
1322	MS-P-C-Pow er Systems Reliability Group	148	4		152
1452	MS-P-Metrology and Instrum Svcs Grp	1,602	13	1	1,616
Other EH&S Services in the 12xx-15xx Range		307	392	294	993
Total		$10,706	$8,273	$4,293	$23,272
Source: OC-554					

Federal Affairs (Service IDs 1784, 1785, 1786, 1787) – Federal Affairs includes development and implementation of key issues impacting the operating companies and the overall direction of PSEG. Federal Affairs represents PSEG and the operating companies before Congress, state legislatures and the executive agencies of the federal government. Functionally it consists of one service, divided into four service IDs to differentiate internal labor from external costs (consultants, membership costs, travel expenses), and "High Control," services from Enterprise services allocable to the corporation as a whole. In 2009, slightly more than half of total cost was allocated, and the remainder was directly charged. Core activities include public policy development, congressional and federal relations and relations with states outside of New Jersey (including lobbying of legislators and executive agencies).

As shown below, the costs incurred by Federal Affairs more than doubled between 2007 and 2008. Most of this was due to an increase in staffing, as internally-provided professional services increased from $745,000 in 2007 to $2.3 million in 2009.

Table 3-14 – Cost Distributions - Federal Affairs & Policy

PSEG Services Cost Distr butions Federal Affairs & Policy ($000s)						
Segment	2007		2008		2009	
	Amount	Pct	Amount	Pct	Amount	Pct
Enterprise	-					
Holdings	82	6%	198	6%	255	8%
Pow er	880	59%	1,916	59%	1,643	49%
Utility	520	35%	1,116	35%	1,469	44%
Total	$1,481	100%	$3,230	100%	$3,367	100%
Source: OC-554						

Finance – This PA consists of internally-provided financial planning, analysis and reporting, and would probably be more properly designated as the Financial Analysis PA. Services are provided on a OC-dedicated basis to Holdings, Utility and Power. Most of the employees providing the service were transferred from positions in the OCs to the service company beginning in 2008.

- Holdings Dedicated Finance – Service ID 1789 consists of financial analysis for renewable energy and capital projects, forecasting & budgeting, scorecard measurement, management reporting and review of internal and external financial statements.

- Power Dedicated Finance – Service ID 1788 includes internal efforts (salaries and benefits) for financial reporting, planning and analysis for Power LLC, including earnings forecasting, monthly close and accounting support, management reporting and business analysis, business planning and benchmarking. Service ID 1805 consists of internal analytical efforts relating to the planning, review and approval of large construction projects.

- PSE&G Dedicated Finance – Service ID 1782 consists of financial reporting, planning and analysis for PSE&G, including services relating to forecasts & budgets, management reporting, scorecard maintenance and the five-year business plan. Service ID 1877 consists of internal employee services for utility capital projects, including forecasts and budgets, management reporting and preparation of presentations.

Distributions to OCs during the review period were as follows:

Table 3-15 – Cost Distributions - Operating Company – Dedicated Finance

PSEG Services Cost Distr butions Operating Company-Dedicated Finance (Financial Analysis) ($000s)						
Segment	2007		2008		2009	
	Amount	Pct	Amount	Pct	Amount	Pct
Enterprise	-					
Holdings	602	33%	680	3%	1,898	7%
Pow er	902	50%	16,375	67%	17,147	62%
Utility	304	17%	7,304	30%	8,605	31%
Total	$1,808	6%	$24,359	83%	$27,650	97%
Source: OC-554						

Human Resources – The HR PA includes a variety of services that can be classified into workforce planning, compensation and benefits, candidate sourcing and recruiting, medical and support services groups. HR cost distributions to OCs during the review period are summarized below. Although it contains more than three dozen separate services, more than 95 percent of the costs during the review period were concentrated in 17 services. As a basis for assessing reasonableness (from a regulated ratepayer perspective), in 2009 the Utility OC accounted for approximately 68 percent of total PSEG employees, but was charged only about 58 percent of total HR cost.

Table 3-16 – Cost Distributions – Human Resources

PSEG Services Cost Distr butions Human Resources ($000s)						
Segment	2007		2008		2009	
	Amount	Pct	Amount	Pct	Amount	Pct
Enterprise	-					
Holdings	201	1%	514	2%	247	1%
Pow er	7,273	37%	9,350	37%	8,935	41%
Utility	12,229	62%	15,081	60%	12,843	58%
Total	$19,703	100%	$24,946	100%	$22,026	100%
Source: OC-554						

- Benefits and Compensation (Service IDs 1612, 1614, 1634 and 1635) – This group of services includes establishing pricing for positions, conducting employee benefit and informational meetings and seminars, conducting benefit and salary studies, and conducting day-to-day employee benefits and compensation work. Services 1612 and 1614 consist primarily of internal labor. They are High Control services, directly billed based on hours charged to each operating company. Services 1634 and 1635 consisting of both internal labor and outside services, are classified as Basic Business and billed to each operating company based on actual monthly headcount.

- Support Services (Service IDs 1163, 1177, 1617, 1620, 1621, 1622, 1623, 1630) – Service 1163, HR System Support and Enterprise Reporting consists of internal labor and manages PSEG's HR

Information System. It is a Basic Business Service billed based on headcount. Service 1177, Information Request, consists of internal labor and provides ad hoc reporting requests, budget data, business specific system testing and consultation. Service 1623, Organizational Design and Effectiveness, consists primarily of internal labor and provides organizational and management consulting support. Service 1163 manages the Human Resource Information System and consists primarily of internal labor. It is classified as Basic Business Service and billed to each LOB based on actual monthly headcount. Services 1620, 1621 and 1622, Manager – Support Services consist of internal labor and provide consultant support to managers regarding HR policies, procedures and programs. Separate service IDs are set up to direct costs to Power, Holding and the Utility.

- Workforce Planning (Service IDs 1149, 1151, 1171, 1613, 1615, 1627, 1636, 1649, 1651, 1838 and 1850) – This group of services includes activities associated with recruiting, retaining and developing management within the Company. It also includes finding solutions to fill skill and resource gaps. Separate service IDs allow these functions to separately account for operating company (directly billed, limited or high control) and corporate (enterprise, allocated) services and for outside services and internal professional services. Service 1850, Workforce Planning and Strategy, consists of outside consulting services which focus on finding solutions to fill skill and resource gaps. It is classified as a Basic Business Service and expense is billed and allocated based on budgeted headcount.

- Training, Employee Development and Performance Measurement (Service IDs 1149, 1151, 1171 1615, 1627, 1636) - Service 1149, Skill Development, consists primarily of outside services and provides leadership development of supervisors, managers and directors. It is a High Control service billed based on actual costs incurred. Services 1151 and 1171, Enterprise Resources Program, relate to outside training costs and internal labor costs associated with salaries and training of MAP participants. Both are corporate expenses allocated using the Enterprise methodology. Service 1615 includes performance management, development and career path services. It consists primarily of internal labor and is billed to the client requesting the work based on number of hours worked. Service 1627 includes outside consulting services with third party invoices billed directly to the operating company requesting the work. Service 1636 consists primarily of internal labor for the management of performance related programs. It is classified as a Basic Business service and is billed based on actual monthly headcount times a billing rate.

- Employee Sourcing and Recruitment (Service IDs 1649, 1650, 1651, 1838) - Service 1649, Sourcing and Recruitment Support, includes outside services for pre-employment testing and background checks. It is a Limited Control service and is directly billed. Service 1650, Recruitment Support, provides management and support for the internal and external job posting process. It includes both internal labor and outside services. It is a Basic Business service and is billed based on headcount. Service 1651, Sourcing and Recruitment, provides internal and external recruitment and selection support. It is classified as Limited Control and is billed directly to the requesting client for the hours worked. Service 1838 includes corporate outreach and diversity programs designed to attract a diverse pool of potential talent to PSEG and consists of both internal labor and outside services. It is a Limited Control service billed based on actual headcount times a billing rate.

- Labor Relations (Service IDs 1153, 1172, 1616, 1617 and 1628) – This group of services includes costs associated with employee relations such as arbitration, negotiating and administering collective bargaining agreements, career assessment, providing for employee advocates and employee investigations, and diversity training. It also includes compliance reporting, HR policies, and working with employee surveys. Separate service IDs allow these functions to separately account for operating company (directly billed, limited control) and corporate (enterprise, allocated) services and for outside services and internal professional services.

- Medical Services (Service IDs 1156, 1157, 1167 and 1179) – This group of services includes general medical services such as workers' compensation and disability case management, managing and administering regulated and non-regulated medical exams, supplies and equipment for medical testing and other services. Services 1156 and 1179 consist of both internal labor and outside services and vendors. They are classified as Transactional / Limited Control. Service 1156 is billed to each operating company based on exams performed. Service 1179 is billed to each operating company based on actual monthly headcount. Service 1157 consists of supplies and equipment for medical testing. It is classified as Professional/Limited Control, and third party invoices are billed to operating companies who request the work. Service 1167 provides medical support to Nuclear and consists primarily of internal labor. It is classified as Professional/High Control, and actual hours worked are billed directly to Nuclear.

A breakdown of amounts charged by OC in 2009, focusing on the most significant services (in dollar terms), is summarized in the following table.

Table 3-17 – Significant Human Resources Service Distributions to Segment in 2009

PSEG Services Significant Human Resources Service Distr butions to Segments in 2009 ($000s)						
Svc ID	Service	Group	Utility	Pow er	Holdings	Total Amount
1149	Skill Development	Training & Development	423	656		1,079
1156	Medical Exams	Medical Services	1,043	218	2	1,263
1163	System Support & Enterp Report	Support Services	995	457	6	1,458
1167	Medical Services Consulting	Medical Services	2	478		480
1171	Enterprise Resources Program	Training & Development	583	448	10	1,041
1153 & 1172	Labor Mgmt Relations	Labor Relations	1,858	484	-	2,342
1179	Medical Svcs	Medical Services	939	431	6	1,376
1613	Employee Enterprise Solutions	Workforce Planning	375	287	7	669
1620, 1621& 1622	Manager Policy, Procedure & Program Support Services	Support Services	1,606	1,857	142	3,605
1634	Compensation Planning	Benefits & Compensation	448	460	14	922
1635	Employee Benefits Admin	Benefits & Compensation	798	367	5	1,170
1636	Performance & Development	Training & Development	537	551	17	1,105
1649	Employment Consulting & Admin	Workforce Planning	118	85	4	207
1650	Recruitment Support	Sourcing / Recruiting	1,165	535	7	1,707
1651	Employment Consulting & Admin	Workforce Planning	525	752	14	1,291
1838	Outreach & Diversity	Workforce Planning	809	371	5	1,185
1850	Workforce Planning & Strategy	Workforce Planning	186	85	1	272
	Other Services	Various	433	413	7	853
Total			$12,843	$8,935	$247	$22,025
Source: OC-554						

Information Technology – The IT PA can be divided broadly into telecom services, hardware and management support services, client projects and application support services. In 2009, the service company spent $151 million on IT. Of approximately 40 services, the 16 services shown in the table below accounted for 90 percent of 2009 spending. IT costs are both information system and employee-driven. As shown in the table below, a majority (71.5 percent) of the amounts spent on IT services are charged to PSE&G. This is consistent with the relative distribution of PSEG employees and information systems among the three OCs (Utility, Power and Holdings).

Table 3-18 – Cost Distributions - Significant Information Technology Services Distributions to Segments in 2009

PSEG Services Cost Distr butions Significant Information Technology Service Distributions to Segments in 2009 ($000s)						
Svc ID	Service Title	Group	Utility	Pow er	Holdings	Total Amount
1182	Basic Telecom Svcs	Telecom	$8,070	$336	$4	$8,411
1210	Corp Extension Service	Telecom	1,692	2,078	17	3,786
1225	Standard Desktop Support	Hardware & Mgt Support	7,035	6,033	82	13,150
1226	Mobile Data Terminal Support	Hardware & Mgt Support	3,722	0	0	3,722
1188	Custom Support	Hardware & Mgt Support	1,824	4,404	179	6,406
1545	PC/MDT w/ Installation (Cap)	Hardware & Mgt Support	2,003	458	0	2,461
1218	Client Projects-O&M	Client Projects	832	3,145	11	3,989
1244	Client Projects-Capitalized	Client Projects	29,267	2,372	0	31,639
1637	Customer Ops App Supt	Application Support	6,075	0	0	6,075
1638	Electric Delivery App Support	Application Support	6,735			6,735
1639	Gas Delivery App Support	Application Support	1,838	0	0	1,838
1641	Nuclear Application Support	Application Support	0	4,367	0	4,367
1642	Fossil Application Support	Application Support	0	1,159	0	1,159
1644	ER&T Application Support	Application Support	0	2,621	0	2,621
1840	Enterprise Application Svcs	Application Support	21,155	11,133	433	32,720
1861	iPower Application Support	Application Support	8,519			8,519
	All Other IT Services		9,646	4,249	38	13,933
Totals			$108,413	$42,355	$764	$151,532
Source: OC-554						

- <u>Telecommunications (Service IDs 1182, 1210, 1211, 1212, 1213, 1214, 1215, 1216, 1217, 1226, 1566)</u> – This service group includes phone-related services such as '800,' teleconference and fax lines (Service 1182), physical phone lines and use of extensions (Service 1210 and 1211), cellular phone services (Service 1213), , special data services that provide support in the event of an emergency (Service 1214), radio network support (Service 1215), support for the private emergency phone system connecting PSEG nuclear to state, county and municipal contacts (Service 1216), support for the customer call center telecom infrastructure (Service 1217), and support for mobile data terminals (Service 1226). In general, these services are classified as either High Control or Basic Business services, and most of these costs are directly billed based on usage.

- <u>Application Support (Service IDs 1637, 1638, 1639, 1640, 1641, 1642, 1644, 1645, 1776, 1840 1861)</u> – Application support consists of vendor contract support, software and hardware maintenance and licensing, system administration and monitoring and operational data backup and recovery, directly billed to benefiting lines of business. Separate service IDs are set up to support customer operations, electric delivery, gas delivery, rate counsel, nuclear generation, fossil generation, Energy Resources & Trading and the enterprise as a whole. In 2009, a separate service (Service 1861) was set up to track the costs of supporting the iPower (customer inquiry and billing) system.

- <u>Client Projects (Service IDs 1218, 1244)</u> - These services include O&M (Service 1218) and capital (Service 1244) project management, analysis, architecture and testing for projects requested by line-of-business clients. They are similar to the line-of-business support services discussed above, but are project-specific. They are billed on a project-based hourly rate to the requesting line of business.

- Client Hardware and Management Support (Service IDs 1184, 1185, 1188, 1208, 1209, 1217, 1224, 1225, 1545, 1652, 1814, 1815) – These services include desktop computer support, mobile data terminal support, move-add-change services, call center infrastructure, mobile access to the PSEG network and "custom support" (client IT management) service.

The distribution of IT costs among OCs is summarized below.

Table 3-19 – Cost Distributions - Information Technology

PSEG Services Cost Distr butions Information Technology ($000s)						
Segment	2007		2008		2009	
	Amount	Pct	Amount	Pct	Amount	Pct
Enterprise	-					
Holdings	1,295	1%	940	1%	764	1%
Pow er	40,164	26%	43,572	25%	42,355	28%
Utility	113,971	73%	132,198	75%	108,413	72%
Total	$155,430	100%	$176,711	100%	$151,532	100%
Source: OC-554						

Internal Audit (Service ID's 1675-1678, 1882-1885) – This PA is divided into internal audit and Sarbanes Oxley services. Services include internal and external audit resources to evaluate and improve the effectiveness of risk management, governance and control processes. Outputs include SOX testing results and evaluations and audit reports and internal control related products. Separate service IDs allow these functions to separately account for operating company or client (directly billed, Basic Business service) and corporate (allocated, Enterprise) services and for outside services and internal professional services. As shown below, costs incurred by the Internal Audit PA declined significantly between 2007 and 2009, due primarily to a reduction in Sarbanes-Oxley services (from $2.4 million in 2007 to $611,000 in 2009). A majority of the Sarbanes-Oxley reduction came from externally-provided services. Although most IA services are "non-Enterprise" services, the distribution of non-Enterprise internal audit services is effectively an Enterprise-method allocation. It is unclear why internal audit services cannot be more directly charged based on the audits being performed.

Table 3-20 – Cost Distributions - Internal Audit

PSEG Services Cost Distr butions Internal Audit ($000s)						
Segment	2007		2008		2009	
	Amount	Pct	Amount	Pct	Amount	Pct
Enterprise	-					
Holdings	671	10%	296	6%	113	3%
Pow er	2,454	37%	2,091	39%	1,521	41%
Utility	3,524	53%	2,968	55%	2,044	56%
Total	$6,649	100%	$5,355	100%	$3,677	100%
Source: OC-554						

Investor Relations – This function is PSEG's interface with the investment community. It provides information, monitors and analyzes financial conditions and provides input to PSEG management concerning investment community perceptions of corporate decisions. Only one service, ID 1359, is used to manage the internal and outside services expenses of this PA. Costs are classified as Enterprise and considered benefit the corporation as a whole. Cost distributions are summarized below.

Table 3-21 – Cost Distributions - Investor Relations

PSEG Services Cost Distr butions Investor Relations ($000s)						
Segment	2007		2008		2009	
	Amount	Pct	Amount	Pct	Amount	Pct
Enterprise	-				-	0%
Holdings		0%		0%	12	1%
Pow er		0%		0%	505	43%
Utility		0%		0%	657	56%
Total	$0	0%	$0	0%	$1,174	100%
Source: OC-554						

The company stated that prior to 2009, Investor Relations service was provided by the Treasury PA, as Treasury Management Service (ID 1347) and that the Investor Relations PA was created as a separate unit when the company hired a VP – Investor Relations.[12] However, Treasury Management service 1347 incurred approximately the same amount of cost in 2009 ($4.6 million), after investor Relations was moved out, as it did in 2007 ($4.4 million), when it was supposed to have included Investor Relations. One possibility is that the service company added Investor Relations without immediately sizing down the staffing associated with Treasury Management.

Law – The Law PA is divided into commercial, corporate and financial transactions, corporate development, labor and employment, property, regulatory, compliance, environmental, preventative law and litigation services. Service IDs allow these functions to separately account for operating company and

[12] Response to Discovery, OC-1095.

corporate (enterprise) services, whether the function is internally provided or an outside service, and whether capitalized or expensed. Legal services include the following:

- Corporate / Financial Transactions (Service IDs 1255, 1256, 1263, 1264) - Issuance and sale of debt and equity securities, corporate governance, and risk management.
- Business Compliance (Service IDs 1250, 1265) - Implementing the Business Conduct Compliance Program, compliance with state and federal rules, ethics advice and overseeing compliance investigations.
- Environmental (Service IDs 1251, 1266, 1278) - Compliance with environmental, health and safety laws. Includes permitting, licensing, enforcement, cost recovery, resource recovery, audit and site remediation.
- Litigation (Service IDs 1253 1254, 1269, 1270) - Personal injury and property torts, contracts, collections, bankruptcy, subpoena response, municipal court issues, accident investigations, shareholder disputes and risk avoidance matters.
- Labor Law (Service IDs 1248, 1257, 1271, 1275) - Labor litigation, representation in labor arbitration, other aspects of labor, employment and immigration law.
- Property (Service IDs 1252, 1258, 1267, 1276) - Real and intellectual property matters.
- Regulatory (Service IDs 1259, 1260, 1268, 1277) - Regulatory matters relating to asset sales, purchases, ownership and operation.
- Energy Transactions (Service IDs 1818, 1819, 1823) - Structuring and negotiation of energy transactions, including credit support and collateral arrangements. Includes services relating to nuclear licensing and commercial agreements.
- Corporate Development (Service IDs 1870, 1871, 1872) - Transaction analysis, negotiation and integration support for acquisitions and mergers.
- Preventative Law (Service ID 1273) - Educational presentations on preventative legal topics.

Audit period cost distributions for the legal function are summarized below.

Table 3-22 – Cost Distributions - Law

PSEG Services Cost Distr butions Law ($000s)						
Segment	2007		2008		2009	
	Amount	Pct	Amount	Pct	Amount	Pct
Enterprise	$138	1%	$152	1%	$17	0%
Holdings	1,775	8%	5,474	20%	2,116	9%
Pow er	9,047	40%	9,098	33%	8,353	36%
Utility	11,812	52%	12,797	47%	12,821	55%
Total	$22,772	100%	$27,521	100%	$23,307	100%
Source: OC-554						

Records and Library – includes services related to protecting, archiving, storing and destruction of corporate records. Services 1799 (enterprise) and 1800 (directly charged as a pass-through) include the costs paid to third parties. Services 1801 (enterprise) and 1802 (directly charged based on client-requested service levels) include internally-provided employee services. Cost distributions are summarized below.

Table 3-23 – Cost Distributions - Records & Library

PSEG Services Cost Distr butions Records & L brary ($000s)						
Segment	2007		2008		2009	
	Amount	Pct	Amount	Pct	Amount	Pct
Enterprise	-					
Holdings	58	4%	101	4%	110	5%
Pow er	524	39%	1,108	44%	997	48%
Utility	751	56%	1,307	52%	985	47%
Total	$1,334	100%	$2,516	100%	$2,092	100%
Source: OC-554						

State Government Affairs (Service IDs 1793, 1794, 1795 and 1796) – This PA includes corporate responsibility and "state government affairs" services. Service 1793 consists of internal salaries and outside services to implement programs to support volunteerism and philanthropy. It is directly billed to specific operating companies. Service 1794 also consists of internal salaries and outside services incurred in support of community events and sponsorships to "advance the PSEG brand." It is considered to benefit the corporation as a whole and is allocated using the Enterprise method. Service 1795 consists of outside consulting to "provide advocacy and education at the state level on issues relevant to PSEG."

Table 3-24 – Cost Distributions - State Government Affairs

PSEG Services Cost Distr butions State Government Affairs ($000s)						
Segment	2007		2008		2009	
	Amount	Pct	Amount	Pct	Amount	Pct
Enterprise	-					
Holdings	20	1%	39	1%	36	1%
Pow er	466	29%	1,432	50%	1,921	42%
Utility	1,143	70%	1,384	48%	2,578	57%
Total	$1,629	100%	$2,855	100%	$4,535	100%
Source: OC-554						

Supply Chain Management -(Services IDs 1341, 1343, 1772, 1844) – The Supply Chain PA includes contract management, strategic sourcing, spending management and procurement operations and "excellence and enterprise logistics" services. Service 1341, Spending Management and Procurement Operations, includes a majority of Supply Chain Management costs, and includes the internal labor associated with management of procurement spending. Companion service 1772 is reserved for "pass through" of outside services costs relating to Procurement Operations. Service 1343, SCM Excellence and Enterprise Logistics, provides "supply chain governance services, including: Office of the VP, Supplier Diversity, Legal & Contract Management, SOX, Scorecard" and other governance services. It is allocated based on the distribution of other Supply Chain services. Finally, service 1844 – Contract Management / Strategic Sourcing, is new in 2008 and exists to separate internal labor associated with capital projects. These Supply Chain costs are capitalized.

Supply Chain distributions among the operating companies for the review period are summarized below. The increase in cost between 2007 and 2009 is due to an increase in department staffing.

Table 3-25 – Cost Distributions – Supply Chain Management

PSEG Services Cost Distr butions Supply Chain Management ($000s)						
Segment	2007		2008		2009	
	Amount	Pct	Amount	Pct	Amount	Pct
Enterprise	-					
Holdings		0%		0%	4	0%
Pow er	7,804	70%	9,518	71%	10,243	69%
Utility	3,383	30%	3,948	29%	4,630	31%
Total	$11,188	100%	$13,466	100%	$14,878	100%
Source: OC-554						

Treasury Management – This PA includes both treasury and corporate properties management activities. Specific services include the following:

- Treasury - This includes cash and capital management, insurance and trust investment, consisting mainly of internal salaries and related expenses (Service ID 1347), bank account fees (Service ID 1351), bank fees for outsourced stockholder services (Service ID 1352), and internal employee salaries relating to stockholder services (Service ID 1353).

- Corporate Property - This includes internal salaries and related expenses for property-related work, including property acquisitions and sales, maintaining the lease relationships on leased properties, property-related investigations and general property management (Service IDs 1344 for capital projects and 1346 for O&M). It also includes fees paid for appraisals, title searches and surveys (Service ID 1345), Corporate Properties (Service ID 1345).

Treasury Management cost distributions to operating companies during the review period are as follows.

Table 3-26 - Cost Distributions – Treasury Management

PSEG Services Cost Distr butions Treasury Management (Treasury and Corporate Properties) ($000s)						
Segment	2007		2008		2009	
	Amount	Pct	Amount	Pct	Amount	Pct
Enterprise	-				$2	
Holdings	684	5%	1,024	8%	804	7%
Pow er	3,606	28%	4,851	38%	3,155	29%
Utility	8,583	67%	7,052	55%	6,899	64%
Total	$12,873	100%	$12,927	100%	$10,860	100%
Source: OC-554						

Servco Accounting and Allocation Processes

Service companies affiliated with utility holding companies are often divided into “corporate” and “shared utility services” organizations, with the latter focused primarily or only on services that can be shared by several utilities. Since PSEG has only one utility, this breakdown does not apply to PSEG Services. The PAs in the service company provide services to three OCs (Utility, Power and Holdings) and to individual lines of business within the OCs. Minor amounts of service, amounting to a fraction of one percent of total service company cost, are retained by the parent by assignment to the “Enterprise” (parent) cost objective.[13] Retained costs consist primarily of Corporate Development. Unlike some utility holding companies, PSEG Services has no procedure or policy that requires the parent to retain a certain percentage of costs benefiting the corporation as a whole. PUHCA-regulated service companies (which PSEG is not) typically retain a small share of costs, usually between 5% and 10%, at the parent level.

Service Taxonomy – In addition to an organizational breakdown into PAs, Servco maintains a number of codes to classify services for the purpose of budgeting, accounting and billing. These include:

- Billing Type – Services are broadly categorized as professional or transactional. In general, professional services consist of internal salaries and related expenses. They are accounted for and billed on an hourly basis or based on dollars incurred. Transactional services include some internal salaries, but also include most services provided by outside vendors. Transactional services are generally charged based on the basis of “cost per transaction” analysis using headcount, invoices, square footage or the average cost to perform an activity (such as setting up a desktop computer or a medical exam). The relative amounts of services by Billing Type are summarized below for the review period.

[13] This should not be confused with the Enterprise allocation methodology used to distribute unattributable costs among the operating companies.

Table 3-27 – Cost Distributions by Billing Type

PSEG Services Corporation Cost Distributions by Billing Type ($000s)						
	Utility	Power	Holdings	Enterprise	Total	
					Amount	Pct
2007						
Professional Services	100,476	76,227	13,817	138	190,658	47%
Transactional Services	137,429	67,508	6,431	150	211,518	53%
2007 Total	$237,905	$143,735	$20,248	$288	$402,176	100%
2008						
Professional Services	117,723	81,234	16,858	161	215,976	48%
Transactional Services	146,402	84,105	5,255	0	235,762	52%
2008 Total	$264,125	$165,339	$22,113	$161	$451,738	100%
2009						
Professional Services	96,753	67,329	9,129	388	173,598	42%
Transactional Services	147,449	88,648	6,475	0	242,572	58%
2009 Total	$244,202	$155,977	$15,604	$388	$416,170	100%
Source: OC-554						

- Degree of Control – The degree of control indicates the designated amount of demand flexibility that "clients" (operating companies and lines of business) have over services charged to them. The categories include:

  - High Control – These are "services in which client demand / consumption decisions directly influence the total cost billed in a given period [and] client decisions / actions drive total volumes [billed]." The CAM cites examples as including IT projects, cell phone usage, corporate extensions usage, personal computer purchases, skill development, postage and pass-through advertising services. During the review period, High Control services accounted for approximately 24 percent of total Servco costs.

  - Limited Control – These are services "mandated by a governing body (BPU, NRC, DOT, etc.);" however, there is some element of client control as to the time period for service delivery. Client actions can drive the timing of service delivery; [however], [s]ignificant demand reductions by [a client] that create stranded fixed costs will be billed to that [client]." Examples cited in the CAM include environmental remediation, licensing and permitting, corporate properties services, certain legal services and medical exams. Limited Control services averaged approximately 11 percent of service company costs during the 2007-2009 period.

  - Basic Business Services – Described as "services used to support the basic operations of the client and where client demand / consumption decisions do not immediately influence total cost billed. . . Clients [may] collaborate for [some transactional] . . . services during the annual planning process; however, the associated cost cannot be shed in the short term (within one year) if actual consumption is less than planned. Clients [OCs] have little or no ability to impact demand for services, since these services are essential for the client operations." Cited examples include corporate accounting and reporting, departmental applications support, desktops, litigation, payroll checks, SAP, treasury management services and law. Basic Business Services accounted for approximately 46 percent of total service company cost distributions during the review period.

- Enterprise Services – The Enterprise billing category includes services that the service company has determined benefit the corporation as a whole. OCs cannot impact costs or service levels. Senior PSEG management sets service levels and approves changes in this category. Examples of Enterprise services include advertising and branding, corporate secretary, security, corporate executive, financial risk management, internal auditing, strategic planning and stockholder services. Enterprise services are distributed using a single size-based allocation factor. During the review period Enterprise services accounted for approximately 18 percent of total Servco cost distributions. As a share of total services, the Enterprise category declined from 20 percent in 2007 to 17 percent in 2009.

Table 3-28 – Cost Distributions by Degree of Control

PSEG Services Corporation Cost Distributions by Degree of Control ($000s)						
	Utility	Power	Holdings	Enterprise	Total	
					Amount	Pct
2007						
High Control Total	67,479	31,870	1,139		100,489	25%
Limited Control Total	25,064	19,253	210		44,527	11%
Basic Bus Svcs Total	100,525	60,180	15,276		175,980	44%
Enterprise Total	44,665	32,432	3,623	289	81,009	20%
Not assigned Total	172				172	0%
2007 Total	$237,906	$143,735	$20,247	$289	$402,176	100%
2008						
High Control Total	85,259	37,961	3,847		127,067	28%
Limited Control Total	26,717	18,591	600		45,909	10%
Basic Bus Svcs Total	112,357	77,999	16,020		206,376	46%
Enterprise Total	39,792	30,788	1,647	161	72,387	16%
2008 Total	$264,125	$165,339	$22,113	$161	$451,738	100%
2009						
High Control Total	58,137	23,968	1,761	2	83,865	20%
Limited Control Total	26,765	17,527	684		44,976	11%
Basic Bus Svcs Total	113,584	80,022	11,701		205,307	49%
Enterprise Total	38,531	29,586	688	386	69,191	17%
Not assigned Total	7,185	4,875	770		12,830	3%
2009 Total	$244,201	$155,978	$15,603	$388	$416,169	100%
Source: OC-554						

- O&M vs. Capital – Most service company costs are O&M. Certain service IDs are reserved for distributing costs directly to capital. Relative amounts charged to O&M expense and capital during the review period are summarized below.

Table 3-29 - Cost Distributions to O&M and Capital

PSEG Services Corporation Cost Distributions to O&M and Capital ($000s)						
	Utility	Power	Holdings	Enterprise	Total	
					Amount	Pct
2007						
O&M	201,426	137,064	20,224	150	358,864	89%
Capital	36,479	6,671	24	138	43,312	11%
2007 Total	$237,905	$143,735	$20,248	288	$402,176	100%
2008						
O&M	210,510	159,669	22,089	9	392,277	87%
Capital	53,615	5,670	24	152	59,461	13%
2008 Total	$264,125	$165,339	$22,113	$161	$451,738	100%
2009						
O&M	204,211	149,282	15,403	369	369,265	89%
Capital	39,990	6,696	201	19	46,906	11%
2009 Total	$244,201	$155,978	$15,604	$388	$416,171	100%
Source: OC-554						

Cost Distributions by Segment and Line of Business - The table below summarizes the distribution of service company costs to OCs and lines of business. It shows that the Utility OC's share of cost was relatively constant throughout the audit period. The maximum annual variation in relative OC distributions during the three years ending December 31, 2009 was less than one percent.

Table 3-30 - Cost Distributions to Segments and Lines of Business

PSEG Services Corporation
Cost Distributions to Segments and Lines of Business
($000s)

Seg.	Line of Business	2007 Amount	2007 Pct	2008 Amount	2008 Pct	2009 Amount	2009 Pct
	PSEG Enterprise	$289	0.1%	$161	0.0%	$388	0.1%
Enterprise Total		$289	0.1%	$161	0.0%	$388	0.1%
	Asset Services Management	433	0.1%	165	0.0%	151	0.0%
	Energy Technology	0	0.0%	0	0.0%	0	0.0%
	Enterprise-Holdings	3,631	0.9%	1,767	0.4%	761	0.2%
	Global	9,531	2.4%	11,382	2.5%	7,024	1.7%
	Holdings	5,478	1.4%	6,296	1.4%	5,981	1.4%
	Resources	1,175	0.3%	2,503	0.6%	1,687	0.4%
Holdings Total		$20,248	5.0%	$22,113	4.9%	$15,604	3.7%
	Construction	1,522	0.4%	1,595	0.4%	1,755	0.4%
	Engineering & Operations	0	0.0%	0	0.0%	814	0.2%
	Energy Resources & Trading	14,137	3.5%	14,895	3.3%	15,386	3.7%
	Fossil Stations	16,805	4.2%	15,161	3.4%	11,542	2.8%
	Fossil Support	13,048	3.2%	21,023	4.7%	18,273	4.4%
	Nuclear-2	45,046	11.2%	50,479	11.2%	45,525	10.9%
	Power Enterprise-2	32,321	8.0%	30,810	6.8%	29,586	7.1%
	Power Support-2	19,473	4.8%	30,005	6.6%	31,867	7.7%
	Servco	1,383	0.3%	1,371	0.3%	1,230	0.3%
Power Total		$143,735	35.7%	$165,339	36.6%	$155,978	37.5%
	Appliance Service	7,881	2.0%	5,130	1.1%	9,505	2.3%
	Asset Mgt & Centralized Svcs	10,286	2.6%	9,579	2.1%	11,699	2.8%
	Corp Rate Counsel	1,221	0.3%	723	0.2%	916	0.2%
	Customer Operations	70,759	17.6%	85,757	19.0%	65,821	15.8%
	Demand Side Management	784	0.2%	373	0.1%	333	0.1%
	Electric Delivery VP	7,861	2.0%	17,397	3.9%	26,615	6.4%
	Electric Distribution	36,486	9.1%	22,347	4.9%	12,087	2.9%
	Energy Acquisitin & Technology	208	0.1%	421	0.1%	1,034	0.2%
	Enterprise-Utility	44,607	11.1%	42,473	9.4%	39,458	9.5%
	External Affairs	882	0.2%	4	0.0%	0	0.0%
	Gas Delivery VP	2,608	0.6%	3,092	0.7%	3,069	0.7%
	Gas Distribution	16,422	4.1%	13,015	2.9%	17,183	4.1%
	Renewables & Energy Solutions	0	0.0%	0	0.0%	666	0.2%
	Transmission	11,652	2.9%	10,890	2.4%	13,053	3.1%
	Utility Executive Office	1,554	0.4%	890	0.2%	221	0.1%
	Utility Finance	26	0.0%	0	0.0%	6	0.0%
	Utility Level	23,076	5.7%	48,165	10.7%	39,287	9.4%
	Utility Marketing & Rev Forecst	763	0.2%	753	0.2%	498	0.1%
	Utility Support Common	828	0.2%	3,116	0.7%	2,748	0.7%
Utility Total		$237,904	59.2%	$264,125	58.5%	$244,199	58.7%
Service Company Total		$402,176	100.0%	$451,738	100.0%	$416,169	100.0%

__Parent-Retained Costs__ - Utility holding companies often "retain" a percentage of services at the holding company level. For example, in 2001, the Securities and Exchange Commission, which at the time regulated Pepco Holdings' service company, negotiated a parent company retention of 10 percent of total service company costs. Although service company accounting and cost allocations are no longer regulated by the SEC, as recently as 2008, PHI continued to retain about 6 percent of service company expenses at the corporate level. As shown above, PSEG Services' equivalent "PSEG Enterprise" (retained) costs during the audit period were 1/10th of one percent or less. Because it is not a multi-state holding company, PSEG has never been subject to regulation under the Public Utility Holding Company Act and PSEG Services has not been subject to SEC regulation. This probably explains why PSEG does not retain a significant amount of Servco cost at the enterprise (corporate) level.

Management Controls

PSEG Services' planning and billing process is structured to facilitate operating company control, to the extent possible, of the services charged to them. From an operating company point of view, the primary control mechanism is the "Degree of Control," discussed above, to which each service is assigned. By analyzing services from a control point of view, and giving the operating companies control of the level of services to the extent possible, the process facilitates cost efficiencies.

During the review period PSEG Services and its client operating companies utilized the following management reports.[14] Many of the reports focus on various breakdowns of budgeted and actual service company spending. Higher-level and detailed reports also cover operating metrics, including Balanced Scorecard, actual vs. budgeted headcount, and safety.

- Flash and Financial Highlights – These monthly reports are a high-level summary of the service company's impact on PSEG earnings and provide a brief explanation of actual to budget (plan) variances.

- Accounting Services Department Monthly Report – This is also a budget variance report showing O&M, capital and combined actual and plan service company charges and variances for each operating company (PSE&G, Power, Holdings, Enterprise) and each line of business within the OCs (for PSE&G these include Asset Management & Centralized Services, Customer Operations, Electric Delivery, Enterprise (whole utility), Gas Delivery, etc.). This report does not include variance explanations.

- SC Charges to PSE&G – This is also a monthly variance analysis of total service company charges. It breaks down actual and budgeted amounts at the service level, and provides brief variance explanations for approximately 170 individual services.

- Key Monthly Financial Results by Operating Company – This report summarizes O&M and capital budgeted and actual billings by operating company. It also summarizes the earnings impact of the billings.

- SC Performance Report – This is a detailed monthly report of service company operations and financial results containing the following sections:

    - Operations, financial services and legal / public affairs Balanced Scorecard results;

[14] Response to Discovery, OC-76.

- Business performance summarizes budget, actual and variance amounts for O&M and capital billings, by type of incurred cost (labor, material, other primary expense, outside services, secondary, indirect and residual), and earnings impact;
- Key financial information in graphic format;
- Controllable O&M earnings impact;
- Analysis of residual and overhead pool variances;
- Analysis of capital billings; and
- Analysis of budgeted and actual headcount levels by PA.

- SC Internal Capital Summary – A breakdown of monthly budgeted and actual capital spending by PA and Cost Element Group.

- Issues and Insights – This is provided to upper management and the board of directors. It contains a variety of operational and financial metrics. The version provided to the board for May, 2009 was in the form of a PowerPoint deck, and included the following:

  - Key Forecast Issues, summarizing year-to-date budget to actual variances;
  - Actual vs. budgeted billings, O&M and capital expenditures;
  - Budgeted and actual headcount by PA;
  - Safety performance (OSHA incidents) and recordable incident rates, actual vs. target; and
  - Key Balanced Scorecard metrics, year to date and for the prior year

Budget vs. Actual Performance – The table below summarizes service company to operating company billing performance compared with the annual budget, broken into O&M, capital and total distributed cost categories.

Table 3-31 – Budget vs. Actual Cost Distributions, O&M, Capital and Total

PSEG Services Corporation Budget vs. Actual Cost Distributions, O&M, Capital and Total 2007-2009 ($000s)					
	Utility	Power	Holdings	Enterprise	Total
O&M					
2007					
Budget (Plan)	$ 211,036	$ 143,279	$ 18,558	$ 1,183	$ 374,056
Actual	201,426	137,065	20,224	151	358,866
Variance	$ 9,610	$ 6,214	$ (1,666)	$ 1,032	$ 15,190
2008					
Budget (Plan)	$ 223,446	$ 171,264	$ 24,571	$ 1,509	$ 420,790
Actual	210,510	159,669	22,089	9	392,277
Variance	$ 12,936	$ 11,595	$ 2,482	$ 1,500	$ 28,513
2009					
Budget (Plan)	$ 211,013	$ 159,452	$ 27,104	$ 302	$ 397,871
Actual	204,211	149,282	15,402	371	369,266
Variance	$ 6,802	$ 10,170	$ 11,702	$ (69)	$ 28,605
Capital					
2007					
Budget (Plan)	$ 21,425	$ 6,968	$ 73	$ 300	$ 28,766
Actual	36,480	6,670	23	138	43,311
Variance	$ (15,055)	$ 298	$ 50	$ 162	$ (14,545)
2008					
Budget (Plan)	$ 80,098	$ 11,191	$ 49	$ 302	$ 91,640
Actual	53,615	5,670	24	152	59,461
Variance	$ 26,483	$ 5,521	$ 25	$ 150	$ 32,179
2009					
Budget (Plan)	$ 33,887	$ 6,007	$ 828	$ 300	$ 41,022
Actual	39,990	6,696	201	17	46,904
Variance	$ (6,103)	$ (689)	$ 627	$ 283	$ (5,882)
Total					
2007					
Budget (Plan)	$ 232,461	$ 150,247	$ 18,631	$ 1,483	$ 402,822
Actual	237,906	143,735	20,247	289	402,177
Variance	$ (5,445)	$ 6,512	$ (1,616)	$ 1,194	$ 645
2008					
Budget (Plan)	$ 303,544	$ 182,455	$ 24,620	$ 1,811	$ 512,430
Actual	264,125	165,339	22,113	161	451,738
Variance	$ 39,419	$ 17,116	$ 2,507	$ 1,650	$ 60,692
2009					
Budget (Plan)	$ 244,900	$ 165,459	$ 27,932	$ 602	$ 438,893
Actual	244,201	155,978	15,603	388	416,170
Variance	$ 699	$ 9,481	$ 12,329	$ 214	$ 22,723
Source: OC-554					

Favorable variances are indicated by positive amounts. As the amounts in the table demonstrate, variances were relatively small during the review period. The most significant variances within a year were capital variances associated with PSE&G. These variances were associated primarily with the iPower (customer service) information system and largely offset one-another over the three year review period, resulting in a favorable variance of $5.3 million for the three-year period, measured against a capital budget of $135.4 million.

O&M variances for the three-year review period totaled $72.3 million favorable, about 6 percent of budgeted O&M of $1.2 billion. Based on a review of performance reports, a key driver of small, consistently favorable O&M variances experienced by the service company appears to be salaries associated with budgeted employee positions that remain unfilled.

Analysis of Direct Charging and Cost Allocation Methods

PSEG Services Corporation has a planning process focused on identifying specific services, activities and the units of service consumed by clients on which costs vary. In many cases, the unit of service is the professional service hour. When a service can be identified with consumption by clients (lines of business within the Utility, Power or Holdings OCs), the unit of service is the billable unit used to directly charge the cost. Because PSEG Services' process is focused on identifying and assigning services to consuming clients (operating companies), a relatively high percentage of its costs are directly charged or directly allocated.

PSEG's CAM describes the Company's general cost allocation philosophy. As a matter of general policy, it states:

> *Whenever possible, services are directly charged. Where direct charging is not possible, the method of allocation used is described below.*[15]

The CAM provides "billing summaries" for 18 service categories that correspond roughly with the approximately two-dozen practice areas the Servco used to collect and charge services during the audit period.[16] These summaries describe the following charging and allocation hierarchy.

1. <u>"Whenever possible, services are directly charged on a professional hourly rate basis"</u> – According to PSEG's CAM, the direct charging of time based on a professional hourly rate is used in 13 of the 18 functional categories listed in the CAM:
    - Accounting
    - Auditing
    - Corporate Development
    - Corporate Communications
    - Environmental, Health and Safety
    - Enterprise Risk Management
    - Human Resources
    - Law
    - Advertising and Branding
    - Supply Chain
    - Public Information and Media Relations
    - Corporate and Strategic Planning
    - Treasury

2. <u>"Whenever possible, services are directly charged, primarily on a transactional basis."</u> - This statement applies to Corporate Business Services, including:

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[15] Response to Discovery, OC-72, PSEG 2009 Cost Allocation Manual, p.99.

[16] Response to Discovery, OC-72, PSEG 2009 Cost Allocation Manual, BPU – Schedule I - Description of Services and Cost Assignment / Allocation Methodologies, pp.99-102.

- Corporate headquarters services and facilities management charged on the basis of square footage
- Transportation services charged on the basis of a price-per-day
- Travel services charged in “dollars per month”
- Accounts payable charged “per invoice”

It also applies to a number of directly charged services billed on a “dollar demand” rather than an hourly basis.

3. “IT Projects are directly billed based on . . . the number of hours worked on the specific project [and] specific identification of materials charged and outside services. IT Products are billed based upon the actual units used, times a pre-established price.”

4. Other “Direct Charge” procedures include:
   - Human Resources recruitment, medical, compensation planning, benefits administration, systems and enterprise reporting, diversity, and performance and development charged on the basis of headcount.
   - Supply Chain “strategic management” services are charged based on “dollars per month.”

Overland’s Analysis of PSEG’s Service Company Cost Distribution Process - Our analysis of the Servco’s cost distribution procedures showed:

- The process emphasizes activity-based cost attribution, meaning, costs are analyzed for their relationship to activities, and activities are the primary basis for cost distribution.
- Approximately 82 percent of costs incurred during the review period were attached to activities and were allocated or assigned using attributable-cost procedures. Although PSEG seems to classify all of these costs as “directly billed,” in fact some are allocated, albeit using attribution-based methods (such as average cost per square foot occupied, average cost per employee, etc.)
- The remaining costs (Enterprise costs), accounting for less than 18 percent of costs incurred during the review period, are distributed using size-based, multi-factor allocators.

In comparison with other utility-industry service companies we have reviewed, 82 percent is a relatively high attributable-cost distribution percentage and 18 percent is a relatively low “non-attributable” allocation percentage.

We categorized the costs distributed during the review period according to billing methodology, as follows:

Table 3-32 – Distribution Amounts by Major Billing/Allocation Method

PSEG Services Distr bution Amounts by Major Billing / Allocation Method ($000s)								
Type of Charge	Coding	2007		2008		2009		
		Amount	Pct	Amount	Pct	Amount	Pct	
Internally-Provided Professional Services Billed Based on Hourly Rates - Various Practice Areas	Professional, Non-PT, All PAs Except IT, Non-Ent	82,508	21%	98,112	22%	86,902	21%	
Externally-Purchased Products and Services "Passed Through" Directly to Operating Companies	All PT, All PAs except IT, Non-Ent	40,489	10%	35,099	8%	24,318	6%	
Transactional Services Billed to Operating Companies Using Various Standard Prices, Consist of Both Internally-Provided and Externally Purchased Services	Transactional, Non-PT, All PAs Except IT, Non-Ent	43,189	11%	69,685	15%	84,539	20%	
IT Services Billed Based on a Project or Product Basis	Professional and Transactional, Non-Ent, IT PA	154,982	39%	176,455	39%	151,220	36%	
"Enterprise" Services Allocated Using a Size-Based Multi-Part Allocator	All "Ent"	81,009	20%	72,387	16%	69,191	17%	
Total		$402,177	100%	$451,738	100%	$416,170	100%	
Source: OC-554								

Internally-Provided "Professional" Services – These consist primarily of services provided by employees and related benefit expenses. Virtually all of these internally-provided professional services (non-IT) are billed at loaded hourly labor rates. The rates are based on productive hours, which are the hours spent providing services (excluding vacation and other non-productive time). Professional hourly rates are designed to recover the following cost components:

- Labor Costs include base salary, overtime, incentive compensation, benefits and payroll taxes.
- "Other Primary Costs" include meals, travel, training, membership fees and similar costs that attach directly to the employees providing the services.
- "Other Secondary Costs" include services directly provided to the PA by another PA, such as application or desktop accounting support provided by the Information Technology PA to most other PAs in the service company. They also may include the application of management costs from the Vice President offices overseeing the PA, because the services of employees in the Vice President offices (the VPs and their administrative assistants) are treated as overheads and not directly billed as services.
- Service Company Overheads – In addition to the cost of support provided directly by another service company PA, there are service company overheads indirectly attributable not only to the operating companies, but to PA's within the service company as well. For example, the cost of corporate security benefits not just to the operating companies, but the service company as well.

The loading factor for service company overheads, applied as a mark-up to the price of most services, was approximately 8.5 percent throughout the three-year review period (2007-2009).

The table below summarizes the pricing process for professional services in the Accounting Services Practice Area for 2009. Individual "Activity Types" in the table correspond with specific management and salary levels of the people providing the services.

Table 3-33 – 2009 Service Price Calculations – Accounting Services Practice Area

PSEG Services
2009 Service Price Calculations
Accounting Services Practice Area - Selected Internally Provided Professional Services

	Labor Product AT Rate	Total	AC-T-Accounting Systems Support (1)	AC-P-Corporate Accounting & Reporting	AC-P-E-Corp Accounting & Reporting	AC-P-E-Sarbanes Oxley 404
Labor Hours: PSEG Associates						
Activity Type 1		6,970	-	6,970	-	-
Activity Type 2		8,785	-	8,785	-	-
Activity Type 3		20,916	1,655	17,089	2,172	-
Activity Type 4		12,092	7,110	2,890	1,350	742
Activity Type 5		3,770	1,625	2,145	-	-
Activity Type 6		2,145	-	1,942	-	203
Labor Cost: PSEG Associates						
Activity Type 1	$ 42.67	$ 297,385	$ -	$ 297,385	$ -	$ -
Activity Type 2	$ 58.37	$ 512,771	$ -	$ 512,771	$ -	$ -
Activity Type 3	$ 69.68	$ 1,457,477	$ 115,324	$ 1,190,802	$ 151,350	$ -
Activity Type 4	$ 88.70	$ 1,072,554	$ 630,653	$ 256,341	$ 119,744	$ 65,815
Activity Type 5	$ 100.20	$ 377,758	$ 162,827	$ 214,931	$ -	$ -
Activity Type 6	$ 131.08	$ 281,166	$ -	$ 254,557	$ -	$ 26,609
Labor Hours: PSEG Contractors						
Activity Type 1		0	0	0	0	0
Labor Cost: PSEG Contractors						
Activity Type 1	$ -	$ -	$ -	$ -	$ -	$ -
Total Labor Cost		$ 3,999,110	$ 908,804	$ 2,726,787	$ 271,094	$ 92,424
Total Material Cost		$ 7,500	$ 1,425	$ 5,462	$ 483	$ 130
Total Outside Services		$ -	$ -	$ -	$ -	$ -
Total Other Primary Costs		$ 71,500	$ 13,587	$ 52,072	$ 4,606	$ 1,236
Total Other Secondary Service Costs		$ 3,632,504	$ 276,562	$ 1,035,885	$ 2,303,407	$ 16,650
Depreciation/Amortization		$ -	$ -	$ -	$ -	$ -
Interest		$ -	$ -	$ -	$ -	$ -
Taxes		$ -	$ -	$ -	$ -	$ -
Allocation of Training Cost		$ 55,050	$ 10,461	$ 40,092	$ 3,546	$ 951
Allocationn of Internal Time Costs		$ 36,700	$ 6,974	$ 26,728	$ 2,364	$ 634
Allocation of Overhead Costs		$ 147,879	$ 28,100	$ 107,698	$ 9,525	$ 2,556
Total Service Costs		$ 7,950,243	$ 1,245,912	$ 3,994,724	$ 2,595,025	$ 114,581
Total Demand			1,245,912	45,656	24,888	976
Billable Unit			DOLLARS	HOURS	HOURS	HOURS
Unloaded Unit Price			1.00	87.50	104.27	117.40
Is Service Eligible for Internal OH Factor?			YES	YES	YES	YES
Internal SC OH Allocation		$ 675,771	$ 105,903	$ 339,552	$ 220,577	$ 9,739
Total Service Costs with SC OH		$ 8,626,013	$ 1,351,815	$ 4,334,275	$ 2,815,603	$ 124,320
Loaded Unit Price			**$ 1.09**	**$ 94.93**	**$ 113.13**	**$ 127.38**
SC Internal OH Factor	8.50%					

Source: OC-553 (Service Pricing Models, Selected Practice Areas)
(1) Accounting Systems Support is a transactional, rather than a professional service. It is included in the table to maintain the integrity of the service totals

Externally-Purchased Products and Services – Services and materials purchased from outside suppliers can be a component of services provided to specific operating companies or considered to benefit the corporation as a whole, allocated using the Enterprise allocation method (discussed below). Services not classified for allocation using the Enterprise allocator can be directly assigned or allocated on the basis of usage, depending on the nature of the service provided. The key characteristic that distinguishes externally-purchased products and services from services provided internally by employees is that overheads are not applied. Thus, the costs of externally-provided services and products are "passed-through" at cost to the operating companies without the overhead loadings discussed above for internally-provided services.

Internally-Provided Transactional Services – Transactional services provided by service company employees differ from Professional services in pricing method. Whereas professional services are generally billed as hours of service at loaded hourly rates, transactional services are billed based on standard units such as number of subscribers (service users), headcount, copies, square footage, or dollars. Services for which the standard unit is "dollars" are actually allocated based on a variety of service-specific methods. For example, the billing methodology for service 1850, Workforce Planning and Strategy, billed based on "dollars," is described as "[b]illed based on actual monthly expense incurred, allocated to businesses based on pro-ration of plan headcount."[17] So, in this case, a "dollars" billed service is actually allocated based on headcount. As shown in the following table, internally-provided transactional services are priced to recover the same categories of cost ("other primary", "other secondary," etc.) as professional services (discussed above).

[17] OC_1094, p.168.

Table 3-34 – 2009 Service Price Calculations – Human Resources

PSEG Services 2009 Service Price Calculations Human Resources Practice Area - Selected Transactional Services											
	Labor Product AT Rate	HR-T-Employee Benefits	HR-T-Compensation Planning	HR-T-HR System Support & Enterp Report	HR-T-Performance & Development	HR-T-Skll Dev	HR-T-Recruitment	HR-T-Outreach & Diversity	HR-T-Medical Svcs	HR-T-Medical Exams	HR-T-Workforce Planning & Strategy
Labor Hours: PSEG Associates											
Activity Type 1		3,370	-	-	869	1,745	7,031	1,683	1,650	3,005	-
Activity Type 2		4,369	834	341	2,500	-	681	1,785	874	751	-
Activity Type 3		-	5,047	4,550	-	-	-	1,611	914	871	-
Activity Type 4		1,789	-	3,034	3,071	-	2,023	-	4,228	975	-
Activity Type 5		1,789	1,290	1,517	466	424	-	1,681	624	582	-
Activity Type 6		601	643	317	2,316	-	2,394	828	1,064	631	-
Activity Type 7		-	-	-	-	-	-	-	-	-	-
Labor Cost: PSEG Associates											
Activity Type 1	$ 42.85	$ 144,388	$ -	$ -	$ 37,249	$ 74,765	$ 301,286	$ 72,127	$ 70,713	$ 128,776	$ -
Activity Type 2	$ 61.02	$ 266,562	$ 50,875	$ 20,807	$ 152,518	$ -	$ 41,554	$ 108,904	$ 53,316	$ 45,825	$ -
Activity Type 3	$ 68.60	$ -	$ 346,168	$ 312,129	$ -	$ -	$ -	$ 110,491	$ 62,680	$ 59,747	$ -
Activity Type 4	$ 103.44	$ 185,021	$ -	$ 313,773	$ 317,600	$ -	$ 209,249	$ -	$ 437,279	$ 100,808	$ -
Activity Type 5	$ 119.82	$ 214,334	$ 154,545	$ 181,742	$ 55,779	$ 50,775	$ -	$ 201,393	$ 74,741	$ 69,737	$ -
Activity Type 6	$ 184.42	$ 110,834	$ 118,536	$ 58,460	$ 427,020	$ -	$ 441,449	$ 152,612	$ 196,175	$ 116,385	$ -
Activity Type 7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Labor Hours: PSEG Contractors											
Activity Type 1		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Labor Cost: PSEG Contractors											
Activity Type 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Labor Cost		$ 921,140	$ 670,124	$ 886,912	$ 990,166	$ 125,540	$ 993,539	$ 645,527	$ 894,903	$ 521,278	$ -
Total Material Cost		$ 16,585	$ 7,743	$ 15,925	$ 5,598	$ 61,317	$ 8,364	$ 49,606	$ 55,678	$ 29,138	$ 5,000
Total Outside Services		$ 18,686	$ 253,973	$ 21,208	$ 35,590	$ 971,491	$ 328,930	$ 238,714	$ 251,142	$ 453,227	$ 108,000
Total Other Primary Costs		$ 74,268	$ 159,472	$ 125,833	$ 302,905	$ 421,670	$ 284,077	$ 203,460	$ 80,054	$ 61,534	$ 24,600
Total Other Secondary Service Costs		$ 129,347	$ 150,385	$ 447,217	$ 154,763	$ 23,538	$ 131,650	$ 82,352	$ 130,480	$ 73,972	$ -
Depreciation/Amortization		$ 3,872	$ 2,539	$ 3,171	$ 2,996	$ 705	$ 3,941	$ 2,465	$ 3,039	$ 2,214	$ -
Interest		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Taxes		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Allocation of Train ng Cost		$ 13,155	$ 8,625	$ 10,772	$ 10,178	$ 2,394	$ 13,389	$ 8,375	$ 10,325	$ 7,523	$ -
Allocationn of Internal Time Costs		$ 35,222	$ 23,093	$ 28,844	$ 27,253	$ 6,410	$ 35,849	$ 22,425	$ 27,644	$ 20,143	$ -
Allocation of Overhead Costs		$ 66,073	$ 43,319	$ 54,108	$ 51,124	$ 12,024	$ 67,250	$ 42,067	$ 51,858	$ 37,786	$ -
Total Service Costs		$1,278,348	$1,319,273	$1,593,990	$ 1,580,572	$1,625,087	$ 1,866,988	$ 1,294,993	$1,505,123	$ 1,206,814	$ 137,600
Total Demand		131,868	49,704	131,868	49,704	1,625,087	131,868	131,868	131,868	1,206,814	131,868
Billable Unit		Headcount	Headcount	Headcount	Headcount	Cost per Trainee	Headcount	Headcount	Headcount	Dollars	Headcount
Unloaded Unit Price		$ 9.69	$ 26.54	$ 12.09	$ 31.80	$ 1.00	$ 14.16	$ 9.82	$ 11.41	$ 1.00	$ 1.04
Is Service Eligible for Internal OH Factor?		**YES**	**YES**	**YES**	**YES**	**YES**	**YES**	**YES**	**YES**	**YES**	**YES**
Internal SC OH Allocation		$ 108,660	$ 112,138	$ 135,489	$ 134,349	$ 138,132	$ 158,694	$ 110,074	$ 127,935	$ 102,579	$ 11,696
Total Service Costs with SC OH		$1,387,008	$1,431,411	$1,729,480	$ 1,714,920	$1,763,219	$ 2,025,682	$ 1,405,067	$1,633,059	$ 1,309,393	$ 149,296
Loaded Unit Price		**$ 10.52**	**$ 28.80**	**$ 13.12**	**$ 34.50**	**$ 1.09**	**$ 15.36**	**$ 10.66**	**$ 12.38**	**$ 1.09**	**$ 1.13**
SC Internal OH Factor	8.50%										
Source: OC-553 (Service Pricing Models, Selected Practice Areas)											

Information Technology Services Billing Methods – During the review period IT services accounted for more than a third of total service company spending. As shown below, most IT services are transactional services billed at various standard service unit rates. IT also performs project-based work for specific OCs and lines of business. Project-based services are professional services performed for specific operating companies. They are billed on an hourly basis and directly assigned to the benefiting operating company.

Table 3-35 – Information Technology Practice Area

PSEG Services Information Technology Pracice Area - 2009 Pricing Methods.							
ID	Service Description	Product / Project	O&M / Capital	Pass-through?	T or P (1)	Client Control	Service Pricing Basis
1182	IT-T-PT-Basic Telecom Svcs	Product	O&M	PT	T	High Control	Pass- hrough based on usage
1184	IT-T-Premium Desktop Support	Product	O&M	Non-PT	T	High Control	Per Unlocked Desktop
1185	IT-T-Unconnected Desktop Support	Product	O&M	Non-PT	T	Basic Bus Svcs	Per Unconnected desk
1188	IT-T-Custom Support	Product	O&M	Non-PT	T	High Control	Directly Assigned
1208	IT-T-MAC Activate	Product	O&M	Non-PT	T	High Control	Per MAC Activate
1209	IT-T-MAC Activate & Install	Product	O&M	Non-PT	T	High Control	Per MAC A&I
1210	IT-T-Corp Extension Service	Product	O&M	Non-PT	T	Basic Bus Svcs	Per Extension
1211	IT-T-PT-Corp Extension Use	Product	O&M	PT	T	High Control	Per Extension
1213	IT-T-PT-Cellular	Product	O&M	PT	T	High Control	Pass- hrough based on usage
1214	IT-T-Special Data Services	Product	O&M	Non-PT	T	Basic Bus Svcs	Per SDS Circuit
1215	IT-T-Radio Netw ork	Product	O&M	Non-PT	T	Basic Bus Svcs	Per Radio
1216	IT-T-Enhanced Netw ork Support	Product	O&M	Non-PT	T	Basic Bus Svcs	Assigned based on Plan
1224	IT-T-Limited Desktop Support	Product	O&M	Non-PT	T	Basic Bus Svcs	Per Thin Window Work
1225	IT-T-Standard Desktop Support	Product	O&M	Non-PT	T	Basic Bus Svcs	Per Locked Desktop
1226	IT-T-Mobile Data Terminal Support	Product	O&M	Non-PT	T	High Control	Per MDT
1545	IT-T-PT-C-PC/MDT w ith Installation	Product	Cap	PT	T	High Control	Per Install
1566	IT-T-PT-C-Basic Telecom Svcs	Product	Cap	PT	T	High Control	Pass- hrough based on usage
1639	IT-T-Gas Delivery Application Support	Product	O&M	Non-PT	T	Basic Bus Svcs	Assigned based on Plan
1652	IT-T-Mobile Access	Product	O&M	Non-PT	T	High Control	Per User Name
1814	IT-T-C-Standard Desktop Support	Product	Cap	Non-PT	T	Basic Bus Svcs	Per Locked Desktop
1840	IT-T-Enterprise Application Services	Product	O&M	Non-PT	T	Basic Bus Svcs	Allocated, headcount & user-IDs
1841	IT-T-Real Time System Support	Product	O&M	Non-PT	T	Basic Bus Svcs	User demand per Plan
1861	IT-T-iPow er Application Support	Product	O&M	Non-PT	T	Basic Bus Svcs	User demand per Plan
1218	IT-P-IT Client Projects-O&M	Project	O&M	Non-PT	P	High Control	Directly Assigned
1244	IT-P-C-IT Client Projects-CAP	Project	Cap	Non-PT	P	High Control	Directly Assigned
Source: OC-554							
(1) Transactional or Professional							

Enterprise Services – Services that are not charged based on an attributable-cost procedure are considered to benefit the corporation as a whole and are allocated using a size-based "enterprise" allocator. As discussed above, during the review period the service company distributed a relatively small percentage of total cost (18 percent) using this non-attributable allocator. During 2007 and 2008, the service company employed two composite allocators (a composite "Massachusetts formula" of revenue, labor and fixed assets, and a composite based on revenue, earnings and capital expenditures). Headcount and relative directly billed law hours were also used for certain costs considered to be Enterprise in nature. The factors for 2008 are summarized in the following table. These allocators produced similar relative distributions in 2007.

Table 3-36 – Enterprise Services Allocation Factors - 2008

PSEG Services Corporation Enterprise Services Allocation Factors - 2008						
Allocator	PSE&G	PSEG Power	Energy Holdings	PSE&G	PSEG Power	Energy Holdings
Modified Massachusetts Formula	$ in millions			Relative %		
Gross Revenues	9,508	7,290	219	56%	43%	1%
Labor (Excluding Fringe)	580	300	5	66%	34%	1%
Net Fixed Assets	8,235	5,560	545	57%	39%	4%
Weighted Percentage				60%	38%	2%
Revenues, Earnings & Cap-X	$ in millions			Relative %		
Gross Revenues	9,508	7,290	219	56%	43%	1%
Earnings	346	1,074	42	24%	73%	3%
Capital Expenditures	832	992	2	46%	54%	0%
Weighted Percentage				42%	57%	1%
Headcount	Headcount			Relative %		
	6,643	2,699	30	71%	29%	0%
Historical Experience -	Hours			Relative %		
Law Hours	24,288	13,013	4,248	59%	31%	10%
Source: OC-550						

Beginning in 2009, the service company condensed three factors into one "consolidated" methodology. The new allocator, used for all Enterprise costs, is based on an equal weighting of net fixed assets, headcount and O&M expense.

Table 3-37 – Enterprise Services Allocation Factors - 2009

PSEG Services Corporation Enterprise Services Allocation Factors - 2009						
Allocator	PSE&G	PSEG Power	Energy Holdings	PSE&G	PSEG Power	Energy Holdings
Consolidated Methodology	$ in millions			Relative %		
Net Fixed Assets	5,676	6,107	564	56%	40%	4%
Headcount	6,271	2,773	104	69%	30%	1%
O&M Expense	788	954	98	43%	52%	5%
Weighted Percentage				56%	41%	3%
Source: OC-550						

PSEG indicated that it communicated this change to the BPU in December, 2008.[18] As shown below, in percentage terms the impact of the change on the Utility and Power OCs was negligible.

Impact of the Change in Enterprise Methodologies on Operating Company Allocations –
As shown below, the 2009 change in the Enterprise allocation methodology had little impact on the percentage of Enterprise costs charged to the Utility OC. The main beneficiary of the change was the

[18] Response to Discovery, OC-550.

Holdings OC. In terms of the percentage increase in costs it would incur if it provided the services on its own (i.e., if it was not part of the PSEG affiliated group), Holdings was the largest beneficiary of the scale economies generated by the service company before the allocation method change. With its relative allocation of Enterprise service costs cut by more than half, it was an even greater beneficiary of scale economies after the method change.

Table 3-38 – Distribution of Enterprise Services Costs

PSEG Services Corporation Distribution of Enterprise Services Costs (1) 2007 through 2009 ($000s)				
	Utility	Pow er	Holdings	Total
2007				
Distribution Amounts	$ 44,665	32,432	3,623	$ 80,720
Percentage	55.3%	40.2%	4.5%	100.0%
2008				
Distribution Amounts	$ 39,792	30,788	1,646	$ 72,226
Percentage	55.1%	42.6%	2.3%	100.0%
2009				
Distribution Amounts	$ 38,531	29,586	688	$ 68,805
Percentage	56.0%	43.0%	1.0%	100.0%
Source: OC-554				
(1) Relatively minor amounts retained by the parent (primarily Corporate Development services), w hich are directly assigned to parent and not subject to the Enterprise allocation process, are excluded				

Convenience Payments

Convenience payments are expenses that are processed and paid by the Service Company for expenses that are under the budget responsibility of the operating companies. Typical convenience payments include employee fringe benefits, materials, outside services, etc. When the information for these expenses is entered into SAP, they are coded to the proper operating company using a company code and general ledger number. Each month, SAP provides a listing of convenience payments showing the expenses paid on the behalf of each of the respective operating companies. This listing is the basis for the amount of cash transferred between the Service Company and the operating companies to reimburse the Service Company.[19]

Overland selected and tested a sample of convenience payments to assess whether the process resulted in proper charges to the operating companies. We sampled a fringe benefit transaction, real estate tax accrual transaction, and a gas remediation program transaction from the month of July 2008. PSEG personnel walked Overland through the process of recording these transactions initially with the Service

[19] Response to Discovery, OC-560.

Company and then allocating the non-Service Company portions of the expense to the operating companies.[20]

PSEG provided Overland with the July 2008 listing of convenience payments from which we selected a sample that would cover significant portion of the total payments for the month. The three transactions selected constituted $15.9 million of the $36.2 million in convenience payments for the month of July, 2008. Following is a discussion of each sampled item.

Sample #1 – Fringe Benefits Transaction – PSEG completes a monthly accrual for employee fringe benefits such as medical, dental, life insurance, long-term disability, etc. We tested $7,060,477 of the $7,432,366 for this accrual entry by reviewing the accrual for medical self-insurance. The medical self-insurance accrual for all of the PSEG entities is based on a calculated percentage of the previous six months of actual costs for the medical benefits. The total accrued amount is distributed to the operating companies based on the planned labor dollars.[21] The following table shows the amounts allocated to the operating companies that total the $7,432,366 of operating company fringe benefits paid for by the Service Company in July 2008.

Table 3-39 – Sample #1 - Fringe Benefits Transaction

DocumentNo	PRw	OTy	Object	CO object name	Cost Elem.	Cost element descr.	PtnrObjTyp	Partner object	CO partner object name	Amount
604220400	356	CTR	1905	Empl Ben Resources	5100100	Benefits - Medical	Order	9A01108A	Fringe Benefits - Nuclear	1,195,124.48
604220400	364	CTR	1905	Empl Ben Resources	5100100	Benefits - Medical	Order	9A01113A	Fringe Benefits - Load Following & Base	307,699.96
604220400	360	CTR	1905	Empl Ben Resources	5100100	Benefits - Medical	Order	9A01110A	Fringe Benefits - SERVCO	192,498.28
604220400	358	CTR	1905	Empl Ben Resources	5100100	Benefits - Medical	Order	9A01109A	Fringe Benefits - ER&T	150,877.03
604220400	372	CTR	1905	Empl Ben Resources	5100100	Benefits - Medical	Order	9A01121	Fringe Benefits-PSEG Pwr Connecticut LLC	112,971.97
604220400	354	CTR	1905	Empl Ben Resources	5100100	Benefits - Medical	Order	9A01107	Fringe Benefits - Power	112,228.73
604220400	368	CTR	1905	Empl Ben Resources	5100100	Benefits - Medical	Order	9A01115	Fringe Benefits - PSEG Power New York	43,850.96
604220400	362	CTR	1905	Empl Ben Resources	5100100	Benefits - Medical	Order	9A01111A	Fringe Benefits - Peaking Operations	38,648.30
604220400	366	CTR	1905	Empl Ben Resources	5100100	Benefits - Medical	Order	9A01114A	Fringe Benefits - Fossil Mgmt Services	26,013.28
604220400	378	CTR	1905	Empl Ben Resources	5100100	Benefits - Medical	Order	9A01131	F B - PSEG Nuclear NG10 BA NO10	8,175.60
604220400	376	CTR	1905	Empl Ben Resources	5100100	Benefits - Medical	Order	9A01130	F B - PSEG Fossil FG10 BA F250	5,945.89
604220400	374	CTR	1905	Empl Ben Resources	5100100	Benefits - Medical	Order	9A01129	Fringe Benefits - PSEG ER&T TR10	2,229.71
604220400	348	CTR	1905	Empl Ben Resources	5100100	Benefits - Medical	Order	9A01102	Fringe Benefits - Elec Distn	1,794,173.19
604220400	370	CTR	1905	Empl Ben Resources	5100100	Benefits - Medical	Order	9A01120	Fringe Benefits - Customer Operations	943,167.27
604220400	346	CTR	1905	Empl Ben Resources	5100100	Benefits - Medical	Order	9A01101	Fringe Benefits - Gas Distn	897,829.83
604220400	344	CTR	1905	Empl Ben Resources	5100100	Benefits - Medical	Order	9A01100	Fringe Benefits - ASB	729,858.36
604220400	350	CTR	1905	Empl Ben Resources	5100100	Benefits - Medical	Order	9A01104	Fringe Benefits-DC10 Delivery Op Support	695,669.47
604220400	352	CTR	1905	Empl Ben Resources	5100100	Benefits - Medical	Order	9A01105	Fringe Benefits - Transmission Service	115,201.68
604220400	380	CTR	1905	Empl Ben Resources	5100100	Benefits - Medical	Order	9A01132	Fringe Benefits - Utility Support	60,202.18

We traced the amounts in the table above to its percentage allocator by using the information in the "Partner object" column. We also traced the total amount to be allocated to the operating companies back to the accrual calculation worksheet. Finally, for each operating company in the table above, we traced a computation of the allocation percentages to the equivalent percentages of 2008 Planned Fringe Benefits.[22] The percentages were successfully traced.

Sample #2 – Real Estate Tax Adjustment – PSEG prepares a real estate tax accrual to be allocated to the appropriate operating companies. Below are the amounts allocated to operating companies that are

[20] Interview with Jeffrey Blocher et al., July 21, 2010.
[21] Response to Discovery, OC-1179.
[22] Response to Discovery, OC-1486.

greater than $100,000. Overland reviewed the allocation for these amounts which equal nearly 98% of the $4.2 million real estate tax accrual for July 2008.

Table 3-40 – Sample #2 – Real Estate Tax Adjustment

CO Code	Doc.no.	DT	Doc. Date	Amount	Header Text	Description	Typ	CoCd
FG10	100022993	SA	39652	1,165,229.93	RE Tax Adjustment	Real Est Tax Acc-NJ	Rec	IS10
NG10	100022993	SA	39652	159,257.90	RE Tax Adjustment	Real Est Tax Acc-NJ	Rec	IS10
PO10	100022993	SA	39652	39,499.32	RE Tax Adjustment	Real Est Tax Acc-NJ	Rec	IS10
DC10	100022993	SA	39652	1,817,809.12	RE Tax Adjustment	Real Est Tax Acc-NJ	Rec	IS10
TC10	100022993	SA	39652	930,335.04	RE Tax Adjustment	Real Est Tax Acc-NJ	Rec	IS10

Overland obtained the method for allocating the amounts to the operating companies. PSEG used the portion of 2007 actual real estate taxes for each operating company to determine the percentage allocation for the 2008 accrual in this sample selection. We obtained the operating company breakdown of the 2007 real estate tax payment and verified that the percentage of the 2007 real estate tax payment paid by each operating company matched the percentage of the 2008 real estate tax accrual allocated to the respective operating company.[23]

Sample #3 – Gas Remediation Costs – The service company accumulated certain costs for the Gas Remediation Program in 2008. The Service Company capitalized these costs and transferred the costs on a monthly basis to the utility (PSE&G).[24] The work order that aggregated these costs that were transferred to the utility in July 2008 is shown below.

Table 3-41 – Sample #3 – Gas Remediation Costs

Co Code	DocumentNo	DT	Doc. Date	Amount	Header Text	Description	Typ	Customer	CoCD
DC10	100025254	SA	39665	4,331,846.44	RC BAL DC10	G-Regl Assets (Envir	Rec	DC10	IS10

Overland verified that these costs were transferred to the utility by reviewing documents and verifying that the amounts were coded to the proper operating company, in this case, PSE&G. We determined that the activities for which payment was made involved remediation work performed for the utility. Since this was work done for the benefit of the utility and not done by the Service Company, it was classified as a convenience payment and the payment flowed directly to PSE&G's balance sheet.[25]

[23] Response to Discovery, OC-1487.
[24] Interview with Jeffrey Blocher et al. July 21, 2010.
[25] Response to Discovery, OC-1488.

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4. PUBLIC SERVICE ELECTRIC AND GAS APPLIANCE SERVICE BUSINESS

This chapter addresses PSE&G's appliance service business including: organization, results and competitive advantages and disadvantages.

Summary of Findings

1. PSE&G and its ASB are not separate legal entities. Most of the resources used by the ASB are also used by the utility (i.e. technicians, vehicles, facilities, support services, etc.).

2. PSE&G annually trains their employees in Appliance Services on the Affiliate Standards. Appliance service technicians are also trained on how to provide service to customers in a non-discriminatory manner. They are also trained to properly record their tasks through job codes that prevent cross-subsidization between tariff and non-tariff activities and costs.

3. The ASB benefits from being associated with the utility and its logo and brand. However, Overland was not able to determine that the ASB was allocated the cost of using or maintaining the utility's logo and brand.

4. ASB's financial results show that it operated with pre-tax margin of no less than 21% during each year in the audit period (2007-2009). We reviewed the costs attributed to the ASB and determined that appropriate categories of direct and indirect operating costs and appropriate overheads were attributed to the ASB. Thus, Overland concludes that as a business, ASB charged prices sufficiently high to exceed its fully allocated cost of providing services.

5. PSE&G's ASB has several competitive advantages over smaller competitors. These include affiliation with the PSE&G and the utility's recognized brand and logo, economies of scale, access to the utility's billing envelope for advertising purposes, use of the customer information system, and use of the utility's customer call center. There are also a few competitive disadvantages, including perception of the utility's monopolistic type of business, restriction to tariffed rates and affiliate standards, and the incurrence of corporate overhead costs associated with the utility holding company.

6. The ASB's floor rates were not high enough to recover the fully allocated cost of providing appliance repair contracts and services in 2009. The hourly service floor rate was $190 in 2009 and increased to $230 in 2010. For 2009, the $190 hourly service rate charged by the ASB was less than the fully allocated costs for the HVAC (Heating, Ventilation, and Air Conditioning) and APSO (Appliance Parts and Service Orders) product lines within the ASB, which had a combined fully allocated cost per hour of $224.91. However, appliance service revenue per hour was significantly *higher* than floor price and fully allocated cost. Furthermore, the floor rate was lower than fully allocated costs for 4 of the 18 types of appliance service contracts in 2009

(cooktop, clothes dryer, clothes washer, and dishwasher). However, the amount charged for the category contract repairs was significantly higher than both the floor price and the fully allocated cost to provide the contracted service. PSE&G completed its ASB financial reporting process and filing with the BPU in February 2010 and issued a revision to the competitive services tariffs, which increased the floor rate to $230 per hour, so that it exceeded the 2009 fully allocated cost of providing appliance services. The revised tariff was effective on March 24, 2010.

Recommendations

1. Overland recommends that PSE&G monitor its fully allocated cost per hour on a more frequent basis (e.g. monthly or quarterly) to ensure that its floor price covers the fully allocated cost of providing appliance services, thereby ensuring continual compliance with EDECA standards.

Background

PSE&G's Appliance Service Business (ASB) has provided appliance service repair and warranty contracts to customers in its service territory for many years. The services provided by ASB are considered "competitive" and are subject to the New Jersey BPU's Electric Discount and Energy Competition Act (EDECA) Affiliate Standards. PSE&G's ASB is broken down into four different product lines. The product lines are listed below as well as their approximate total revenue for 2009.

- Retail service "Worry Free" contracts ($89 million)
- Replacement installations for water heaters ($15 million)
- HVAC services ($25 million)
- APSO For-fee services for non-contract customers ($7 million)[1]

The gross profit earned by the appliance services business offsets the revenue requested in the base rate case for providing gas distribution service[2] in accordance with NJAC Section 14:4-3.6(r).

Organization

During the audit period, the ASB operated as a business unit within the utility. This caused it to fall under the Affiliate Standards of the New Jersey Administrative Code in section 14:4-3.6, which applies to the competitive business segments of a utility.[3] As of February 2010 there were approximately 790 service technicians capable of doing both appliance services work and utility work. There is a management staff of 100 to 150 in place in PSE&G's gas delivery function that supports the technicians. In addition, there are approximately 50 "white goods" technicians that work predominantly, but not

[1] Appliance Services Interview, February 4, 2010 with Joe Bassolino, Lynn Evan, and Rich Aicher. Revised from $8 million based on more accurate information reported in the 2009 Summary of Competitive Product/Service Accounting Standards, Books, and Records (N.J.A.C. 14:4-3.6(n)(1) through (n)(10)).

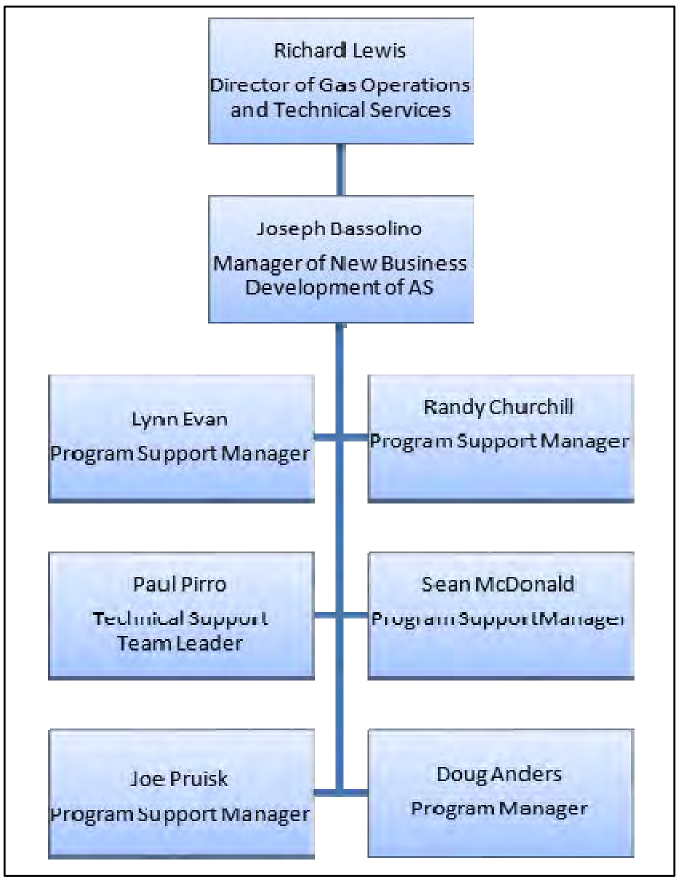
[2] Response to Discovery, OC-1165.

[3] Response to Discovery, OC-60.

exclusively, on appliance service jobs. Just as there are no dedicated appliance service technicians, there are no PSE&G departments dedicated solely to appliance services. PSE&G's ASB also makes use of contractors when it is necessary to utilize the skills of a licensed electrician or plumber.[4]

The organizational structure of the ASB is somewhat complex. The appliance service technicians (ASTs) are utility service technicians that are capable of providing repairs and maintenance for appliances report to the district manager for their gas territory. These technicians not only repair and perform maintenance on appliances, but also provide utility services such as safety related services with respect to the customer's gas service line. There are several district managers that report directly to two appliance services directors, Mr. Michael Schmid, Mr. Jeffrey Clayton and Mr. Michael Gaffney. These directors ultimately report to the VP – Gas Delivery. For ASB support services, the following organizational chart depicts the reporting relationships.

Table 4-1 – Appliance Services Organizational Chart



Source: Response to Discovery OC-1270

Richard Lewis – Director of Gas Operations and Technical Services also reports to the VP – Gas Delivery.[5]

4 Appliance Services Interview, February 4, 2010 with Joe Bassolino, Lynn Evan, and Rich Aicher.
5 Response to Discovery, OC-1270.

Training

ASB employees are provided with specific training concerning the compliance with Affiliate Standards. This training is provided annually and includes training for the New Jersey and federal affiliate rules.[6] ASTs are provided with special training scenarios that represent real-life examples of how to provide appliances services while interacting with customers in a manner that eliminates the risk of using discriminatory practices and also ensures that there is no cross-subsidization between competitive and tariff services.[7] Furthermore, there is a Service Person Instruction Manual to guide ASTs on how to record their time for tariff and non-tariff services using the job codes provided in the manual. This manual helps ASTs to record their work properly to help minimize the risk of cross-subsidization between tariffed and non-tariffed services.[8]

Organizational Separation

According to the New Jersey Administrative Code, electric and/or gas utilities are prohibited from offering competitive products or services unless approved by the New Jersey Board of Public Utilities.[9] However, the NJAC does provide a grandfathering provision to those utilities providing competitive products and services that were offered in New Jersey prior to 1993. PSE&G's appliance service business falls into this grandfather clause and is not prohibited in the NJAC, even though it is not organizationally separate from the utility.[10]

Accounting Separation

As a business unit within PSE&G, the ASB's activities are recorded on PSE&G's books. There are separate general ledger accounts within the accounting information system (SAP) that is identified with the appliance service business unit revenues.[11] To determine how the revenue is recorded in SAP, sales documents are created with the customer location that drives which profit center or gas district receives the revenue and the job code that drives the type of the service provided. The profit center/gas district and job code is mapped to its own set of settlement receiver orders in SAP. These orders are then mapped to the different product types and categories of revenue for reporting purposes.[12]

Corporate Governance and Management Separation

During the period under audit, the appliance service business reported up through the gas delivery business segment. The Division Manager and District Manager of Appliance Services report through the Vice President of Gas Delivery and eventually the President and COO of PSE&G. [13]

[6] Response to Discovery, OC-562.
[7] Id.
[8] Response to Discovery, OC-1166.
[9] NJAC Section 14:4-3.6(a).
[10] NJAC Section 14:4-3.6(b)-(c).
[11] Interview with Joe Bassolino – Manager of Business Development for Appliance Services, 7/20/10.
[12] Response to Discovery, OC-1169.
[13] Response to Discovery, OC-1270 p. 115.

Office and Operating Facilities Separation

Appliance service technicians are home-based. They do not require dedicated space in utility offices or operations centers. They are assigned to one of twelve districts that roll up within three gas divisions that make up PSE&G's service territory.[14] The support services that provide the "back office" functions for ASB resides on the 14th Floor of the Corporate Headquarters in Newark, New Jersey. The 14th Floor is also home to many of the utility's gas support services.[15]

ASB holds its competitive services inventory (appliance service part, HVAC equipment, etc.) in a segregated part of each gas district storeroom. This is done to prevent access to the appliance services inventory by non-service technicians.[16]

There is no dedicated customer service center for ASB. Customer calls relating to appliance services are routed to call center location in the northern and southern part of the territory. The Northern Center is located in Cranford, NJ and the Southern Center in Bordentown, NJ. Customers that call are prompted with specific options in the automated call response system that directs the customer to the appropriate call representative. In addition to the main phone number, customers can call a dedicated phone number for water heater and HVAC replacements.[17]

Asset Separation

ASB uses a variety of assets owned by the utility to complete their work. These include vehicles, operating center facilities, appliance service parts and information systems. PSE&G vans are assigned to specific home-based technicians. The vans are uniquely marked with the "Worry Free" logo.[18] Since the technicians are capable of completing both competitive (AS) services and non-competitive (utility) tasks, there is no clear segregation of the assets involving the vehicles and the equipment contained within the vehicles. Service parts (materials) and related handling costs are directly charged to specific ASB product lines. Other materials (also called consumables) are allocated to the ASB jobs based on premise hours. Consumables include items such as: work gloves, safety glasses, and other safety equipment.[19] The ASB has access to the same customer information system as the utility does.[20]

Employee Separation

The service technicians that provide appliance services must track the time spent on a premise visit based on the service provided, whether it be a utility service or a competitive service. Each technician carries a mobile data terminal in which time for each task performed during a premise visit is entered. Each task is given a pre-validated job code in the utility's work management system. The job code

[14] Interview with Joe Bassolino – Manager of Business Development for Appliance Services, 7/20/10.
[15] Response to Discovery, OC-976.
[16] Response to Discovery, OC-1170.
[17] Response to discovery request, email from Mally Becker, dated 11/22/11.
[18] Appliance Services Interview, February 4, 2010 with Joe Bassolino, Lynn Evan, and Rich Aicher.
[19] Response to Discovery, OC-561 SUPPLEMENTAL.
[20] Interview with Joe Bassolino – Manager of Business Development for Appliance Services, July 20, 2010.

determines whether the cost for the time spent on the specific task should go to a utility service or a competitive service. Typically, the utility service involves inspecting and diagnosing problems related to the customer service line, meters, and meter connections. The competitive service focuses on repairing and replacing the customer's appliances.

As noted above, utility service technicians perform both regulated utility tasks and unregulated appliance services tasks. PSE&G places more importance on separating the tasks performed by these technicians based on the job codes that provide descriptions of the work that was done by the technician during a premises visit than having a separate group of technicians solely dedicated to appliance services. This allows PSE&G to obtain more flexibility with the human resources it has at its disposal. PSE&G has not considered moving appliance services into a separate affiliate since the late 1990s.[21]

Although performing both utility and appliance service work enhances the customer-focus of the ASB's activities, it also serves to blur the line between competitive appliance services and non-competitive utility distribution services. It is difficult for the general public to distinguish between the ASB and the utility when it sees the same service technician providing both types of service. Allowing ASB technicians to only perform appliance services is the only way to provide full separation of the utility and appliance businesses.

Centralized and Shared Services

The ASB uses PSE&G and PSEG to provide administrative functions that include human resources, information technology, marketing and accounting. The ASB has a detailed process for allocating shared services costs to the ASB using a variety of cost allocators. The primary allocators are premises hours and premises visits. We reviewed the process of how these shared costs are calculated and allocated to the ASB.[22] The process appeared reasonable and appeared not to have omitted any significant cost from being allocated to the ASB.

ASB Marketing

The ASB's marketing function is led by the Director of Utility Marketing – Dominic Facchini. Reporting to the Director is the Manager of Customer Campaigns – Marnie Masseri. Ms. Masseri manages a team responsible for direct mail, bill inserts, trade catalogs, seminars, trade shows, newspaper ads and web content.[23] Though ASB has access to the utility's customer information system, it was noted in an interview with Joe Bassolino that the ASB does not use the system to develop new marketing plans to target specific PSE&G customers for new ASB services.[24] The customer information system does enable the ASB to conduct advertising campaigns such as: direct mail, telemarketing, and bill inserts. The only

[21] Appliance Services Interview, February 4, 2010 with Joe Bassolino, Lynn Evan, and Rich Aicher.
[22] Interview with Ken Burgos – Business Planning Manager and Rich Aicher – Manager SAP Strategy and Planning, July 21, 2010.
[23] Interview with Joe Bassolino – Manager of Business Development for Appliance Services, July 20, 2010.
[24] Id.

discount offered by the ASB is a 10% discount on three or more current Worry Free appliance service contracts.[25]

Utility and Corporate Brand Association

The ASB promotes its services under the "Worry Free" trademarked name. The trademark is prominently displayed on all of the appliance service technicians' vans. Also, displayed on the vans is PSE&G's name and logo (the sunburst logo). Since the ASB is a part of the utility and not an affiliate, the ASB is permitted to use the utility's name and logo to promote its competitive services.

Appliance Service Profitability, Pricing, and Cross-Subsidization

Financial Results

The following table summarizes the financial results of the ASB for the year ended December 31, 2007, 2008 and 2009.

Table 4-2 - Summary of Financial Results [Begin Confidential]

Appliance Service Business Summary of Financial Results			
	12 Months Ended 12/31/07	12 Months Ended 12/31/08	12 Months Ended 12/31/09
[redacted]			

[End Confidential]

The table above demonstrates that the ASB is pricing its services in a manner that allows it to recover its identified costs. Administrative expenses include allocations of shared corporate and utility costs. As shown in the table above, there were significant increases in administrative expenses allocated to ASB. Several components of administrative expenses contributed to this increase.

[25] Id.

- ITS costs rose from **[Begin Confidential]** **[End Confidential]**. The increase was caused by the cost of implementing the new customer care system[26] (iPower).
- The rate for uncollectible revenue expense tripled in the 2nd half of 2009, which caused this component of administrative expense to increase significantly from **[Begin Confidential]** **[End Confidential]**. The increase was most likely caused by the difficult economic climate leading up to that timeframe.
- The cost of technician travel to and from the premises increased from **[Begin Confidential]** **[End Confidential]**. Most of the increase is due to an increase in pension costs. Pension costs are included in a fringe rate allocated to this administrative expense. Also, an increased amount of labor was allocated to this administrative expense due to technicians spending time learning how to transition to the new work management system and iPower.
- Finally, the cost of dispatch service increased from **[Begin Confidential]** **[End Confidential]** for the same reasons that the cost of technician travel increased. [27]

PSE&G briefed Overland on the process by which these costs are allocated to the ASB. Based on the an analysis of the ASB's direct and indirect (allocated) costs, as well as an analysis of the allocated costs of shared corporate services, Overland determined that the ASB is not subsidized by the non-competitive segments of the utility or by other PSEG affiliates as defined in the NJBPU's competitive services rules, which require prices to cover or exceed a full distribution of costs.[28] Moreover, ASB's revenues exceeded its fully distributed costs; thus, ASB's prices were not subsidized by non-appliance revenue sources (e.g. tariffed utility services) during the audit period. However, as a part of the utility, the ASB benefits from a number of intangible assets, including the use of the PSE&G logo, the billing envelope, various utility information systems and utility management expertise. The ASB also benefits from utility scale economies. As a business unit *within* the utility, the ASB is not required to compensate the utility or its shareholders for the economic value of these benefits; rather, it is only required to pay for a distribution of their costs under fully distributed cost principles.

ASB Pricing

To determine the reasonableness of ASB pricing, Overland obtained the fully allocated cost per appliance service technician hour as shown in the ASB cost allocation study. See the table below.

[26] Response to Discovery, OC-1177.
[27] Response to Discovery, OC-561.
[28] Allocation of shared corporate services is discussed in Chapter 3. As discussed in that chapter, we determined that the PSEG Services allocation procedures and controls are sufficient to prevent material misallocations of corporate and shared services costs.

Table 4-3 - Audit Calculation of Fully Allocated Cost per AST Hour [Begin Confidential]

Appliance Service Business Audit Calculation of Fully Allocated Cost per AST Hour			
	12 Months Ended 12/31/07	12 Months Ended 12/31/08	12 Months Ended 12/31/09
[redacted]			

[End Confidential]

We used the amounts in the table above to compare with the "floor prices" to determine whether PSE&G's ASB was charging customers a high enough price to recover their fully allocated costs, thereby removing the possibility of cross-subsidization from the utility or other PSEG affiliates.

Floor Prices

According to PSE&G's Appliance Service Tariff, floor prices are the prices PSE&G charges for its appliance services. Under EDECA's Affiliate Standards, floor prices must be set no less than the fully allocated cost of the services.[29] The tariff contains floor prices for residential contracts, small commercial contracts, and maintenance services. The floor prices for the HVAC and APSO services are based on the combined hourly service rate for the two product lines, which is the total cost to provide HVAC and APSO services after subtracting out all materials and materials-related charges. During the audit period, the hourly service rate charged was $190. As shown in the table above, in 2007 and 2008 the floor prices charged recovered the fully allocated cost per premises hour for HVAC and APSO service. **[Begin Confidential]**

[30] **[End Confidential]** The hourly service rate increased from $190 to $230 when the 8th revision of the ASB Tariff went into effect on March 24, 2010.[31] PSE&G's floor prices for APSO and contract services appear sufficient to recover fully allocated cost according to PSE&G's own cost calculations as of March 2010.

The floor prices of contract services are based on the cost (including materials) of providing a particular type of contract service. Overland reviewed the fully allocated costs of providing the contract services. Using the information provided by PSE&G, it appears that the floor prices of the contract services were higher than the fully allocated cost of providing those services, except for cooktop, clothes dryer,

[29] Response to Discovery, OC-1168.
[30] Response to Discovery, OC-561 SUPPLEMENTAL
[31] Response to Discovery, OC-1168.

washing machine and dishwasher contract services.[32] The floor prices of the contract services provided by the ASB were revised in the 8th revision of the ASB Tariff that went into effect in March 2010 to ensure that the floor price exceeded the fully allocated cost of providing each type of ASB contract services. Overland reviewed the floor prices set forth in the 8th revision of the tariff and concluded that the floor prices exceeded the fully allocated cost for each type of contract service. See the table below for details.

Table 4-4 – Selected Comparison of Floor Rates and Fully Allocated Costs [Begin Confidential]

Appliance Service Business Selected Comparison of Floor Rates and Fully Allocated Costs				
Rate Schedule	Description	Original Floor Price	2009 Fully Allocated Cost	Revised Floor Price
[redacted]				
[redacted]				
[redacted]				

[End Confidential]

Current Customer Rates

Overland obtained from PSE&G a listing of ASB prices as of August 2010. It appears that the current customer rates are significantly higher than the floor prices that were created based on fully allocated costs. With customer prices at the levels shown below, there is no appearance of cross-subsidization. See the table below for a comparison of floor rates and current customer rates as well as the percentage mark-up.

[32] Response to Discovery, OC-561 SUPPLEMENTAL.

Table 4-5 – Selected Comparison of Floor Rates and Tariffed Prices

Appliance Service Business Selected Comparison of Floor Rates and Tariffed Prices				
Rate Schedule	Description	Floor Rate	Customer Price	% Mark-Up
Residential	Central House Heating	45.99	77.88	69.34%
Residential	Water Heater	14.69	28.50	94.01%
Residential	Clothes Dryer	44.99	58.17	29.30%
Residential	Range	53.99	73.83	36.75%
Residential	Wall Oven	35.99	61.63	71.24%
Residential	Cooktop	39.99	49.18	22.98%
Residential	Electric Central Air Conditioner	87.49	147.15	68.19%
Residential	Refrigerator	62.99	90.39	43.50%
Residential	Dishwasher	64.99	83.97	29.20%
Residential	Washing Machine	49.99	64.59	29.21%
Residential	Gas Piping	17.99	23.63	31.35%
Residential	Gas Fireplace	53.99	70.62	30.80%
Residential	Stand-alone Freezer	53.99	73.83	36.75%
Small Commercial	Rooftop Heater	85.00	117.61	38.36%
Small Commercial	Central Heating	85.00	117.61	38.36%
Small Commercial	Water Heater	34.00	46.99	38.21%
Small Commercial	Electric Central Air Conditioner	136.00	188.23	38.40%
Small Commercial	Rooftop Electric Air Conditioner	136.00	188.23	38.40%
Maintenance	Central Heating and Water Heating Tune-up Program	230.00	230.00	0.00%
Maintenance	Central Air Conditioning Start-up Program	230.00	230.00	0.00%

Note: The floor rate does not include taxes while the customer rate does include tax (except for the maintenance services). Overland believes that the percent mark-up far exceeds any expected sales tax that a customer might incur.
Source: Response to Discovery, OC-1167 and OC-1168.

Discounted Contracts Program

The ASB provides a 10% discount to customers with contracts covering at least three appliances.[33] Given the fact that the rates customers are being charged for appliance service contracts are significantly marked up from the floor price, which represents the fully allocated costs of the service contracts, a 10% discount does not depress the customer price to a level below the floor price shown in the Appliance Service Tariff, even after taking into account that the floor price does not include taxes while the customer rate does. The volume discount offered to customers does not appear to create a cross-subsidization among PSEG affiliates or ASB customers.

[33] Interview with Joe Bassolino – Manager of Business Development for Appliance Services, July 20, 2010.

Analysis of the Competitive Market Advantages and Disadvantages Associated with Utility Affiliation

Although a detailed review of the appliance services market within the PSE&G service territory is beyond the scope of this audit, it is useful to briefly examine the competitive advantages and disadvantages that accrue to an appliance service business maintained within the utility. Overall, the advantages outweigh the disadvantages.

Competitive Advantages

The first advantage that the ASB enjoys is its affiliation with the utility brand. The ASB is allowed to use utility technicians and vehicles that prominently display the PSE&G name and logo. The PSE&G name is well known in the state of New Jersey. A greater percentage of adults recognize the utility brand than they would a smaller appliance services competitor. Furthermore, the utility brand exudes a certain level of trust and reliability that only a stable, large company can provide. PSE&G can point to its long history of providing reliable service, whereas smaller companies do not have such history to draw from. The cost or value of this brand affiliation is not reflected in the cost study that was provided to Overland.

The second advantage is economies of scale. PSE&G's territory includes 2.1 million electric and 1.7 million gas customers.[34] PSE&G's ASB can extract economies of scale that smaller competitors cannot as the PSE&G geographic reach is larger.

Another advantage is ASB's access to the utility's billing envelope as an advertising tool. The ASB's ability to advertise by using the billing inserts is a significant competitive advantage over smaller appliance service companies. Access to the billing envelope provides access to 2.1 million electric and 1.7 million gas customers on a monthly basis. The cost (developing the promotional material, printing, and any incremental postage) of utilizing bill inserts for advertising purposes is relatively small for PSE&G's ASB. However, beginning with the postage costs for doing a similar mailing, for a smaller appliance services company, the costs would be significantly higher to reach the same customers. ASB pays PSE&G to include their inserts in customers' bills and the costs are part of the marketing costs allocated to the ASB.[35]

The use of the utility's customer service function and information system is also an advantage for PSE&G's ASB. The ASB utilizes PSE&G's northern call center in Cranford, New Jersey to handle customer inquiries relating to appliance services. Smaller appliance service companies do not have access to large scale call centers to handle customer inquiries like PSE&G ASB does, and maintaining a call center dedicated to a small appliance service company would not be economically feasible in most cases. Furthermore, if it were economically feasible, the call center would not contain the valuable link to the utility, which could also provide services related to the supply of electricity or gas to the property. The

[34] PSEG 2009 10-K.
[35] Interview with Joe Bassolino – Manager of Business Development for Appliance Services, July 20, 2010.

PSE&G ASB is allocated costs from the call center. However, those costs would be significantly higher if it had to build and maintain a stand-alone call center that was not tied to the utility.

Competitive Disadvantages

There may be some people that seek to avoid using utility services whenever possible due to the utility's monopoly status or because they have had bad customer experiences with the utility in the past. Overland does not believe this is the case in most instances, especially as PSE&G spends a substantial amount of resources reaching out to individual customers and communities within their service territory.

The ASB is required to file a tariff with floor rates that represent the fully allocated cost of providing various appliance services. The rates that the utility's ASB must charge its customers must be higher than the floor rates in order to prevent cross-subsidization of the ASB by the utility and its other affiliates. Small appliance service companies that are not tied to a utility do not have this restriction. Overland noted that in some cases the ASB did not maintain prices to sufficiently recover the fully allocated cost for some of the offered appliance services.

The ASB is also required by Affiliate Standards to incur corporate administrative expenses that small appliance service companies not tied to utilities may not incur. Smaller companies are not likely to incur costs relating to executive management, treasury, investor relations, and legal function in the same manner or magnitude that PSE&G's ASB incurs. However, the allocation of costs from corporate and back office functions have a relatively small effect on the profitability of the ASB, making this a minor issue.

Follow-up on the Recommendations from the Prior Audit of Appliance Services

In the previous audit of the appliance services business, there were three recommendations that were given to PSE&G to implement. These recommendations and any follow-up undertaken to implement them are described below.

1. <u>Include the cost of capital and installment-sale balances when calculating the costs of Appliance Service's competitive offerings.</u>

   During the course of the audit, the previous auditor found PSE&G did not include computations of the cost of the working capital of equipment installed by PSE&G, but not yet paid for by the customer through installment payments. Also during that time, PSE&G did not calculate a cost of capital (ROI) on the assets that were allocated to appliance services.

   As the final report of the previous auditor was submitted, PSE&G had a proposal in front of the NJBPU for a method of calculating the cost of capital for assets allocated to appliance services as well as the installment sales recorded on the books of ASB.

Overland reviewed the submission to the BPU of appliance services financial data and determined that the filing for the period January – December 2009 contained calculations of a return on assets as well as a calculation for the carrying cost of accounts receivable (installment sales).[36]

2. <u>Require that CSPs speaking with customer about APSO repairs inform customers as a matter of course that repair services may also be provided by third parties who can be found in the telephone directory.</u>

   In a letter to the NJBPU on December 15, 2005 concerning PSE&G's reaction and timeline to implement the prior audit's recommendation, PSE&G stated that this recommendation had been implemented. Overland also obtained training materials issued to PSE&G CSPs showing the implementation of this recommendation.[37]

3. <u>Include in the Compliance Plan a statement addressing Section 14:4-3.6(q).</u>

   Our review indicated that wording consistent with the proposed changes was included in the 2009 Compliance Plan.[38] No additional company action to address these specific recommendations is necessary.

[36] Response to Discovery, OC-561.
[37] Response to Discovery, OC-1470.
[38] Based on a review of the PSE&G July 1, 2009 Compliance Plan provided in response to Discovery, OC-60.

5. ORGANIZATIONAL STRUCTURE

This chapter provides an overview of PSEG's organization. It compares and contrasts the legal and management (functional) organizations, explains the interrelationships between the PSE&G and PSEG Service Company legal entities within the management structure, and describes the functional organizations within the management structure and their key responsibilities. The final section of this chapter discusses PSEG's nuclear operations.

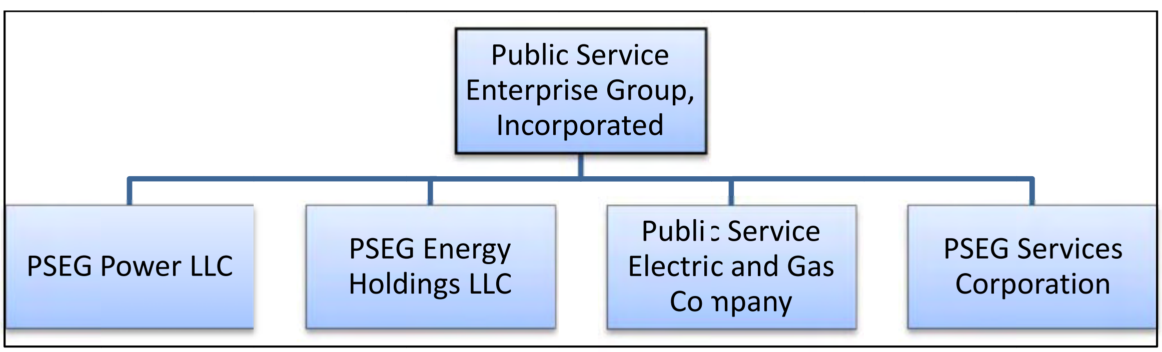
PSEG's Legal Organization Structure

PSEG's legal entity (affiliate) organization structure is summarized below. This chapter discusses PSEG's management organization, and explains how the legal and management organization structures relate to one-another.

PSEG's businesses are organized into various legal entities, which consolidate to form four principal operating subsidiaries. These four subsidiaries are:

- PSEG Power – This subsidiary owns generating assets and its major functions are wholesale energy sales, fuel supply, energy trading and marketing and risk management functions.
- PSE&G – This subsidiary consists of a regulated utility providing electric and gas distribution to residential, commercial, and industrial customers within PSE&G's service territory.
- PSEG Energy Holdings – This subsidiary manages leveraged lease investments, operates domestic generation projects and pursues renewable generation projects.
- PSEG Service Company – This subsidiary provides support functions to all PSEG affiliates.[1]

Table 5-1 – PSEG Legal Organization



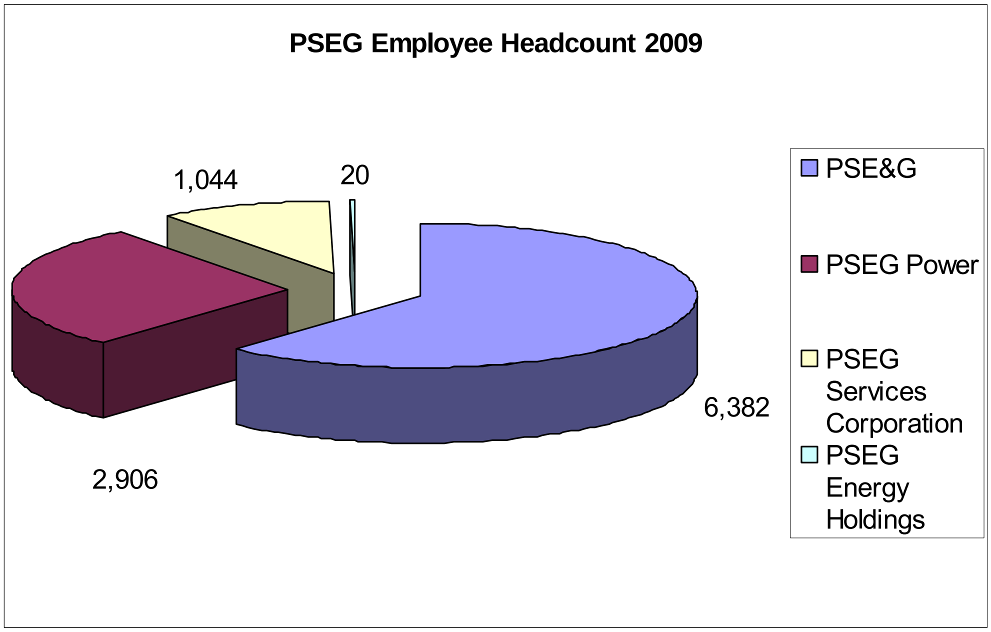
Overview of PSEG's Management Organization Structure

PSEG's management organization is structured to serve the four major operating subsidiaries described above, with a major emphasis on the electric and gas utility, PSE&G. PSE&G is responsible for

[1] 2009 PSEG 10-K.

approximately 61% of PSEG employees. PSEG Power is responsible for 28% of PSEG employees. PSEG Services Corporation is responsible for 10% of PSEG employees. Finally, PSEG Energy Holdings contains 1% of PSEG employees. See graph below for actual data for 2009.

Table 5-2 – PSEG's Management Organization Structure



Source: Response to OC-98 (UPDATE)

The following table provides an historical comparison.

Table 5-3 – Employee Headcount

Major Corporate Entity	12/31/2007	12/31/2008	12/31/2009
PSE&G	6,069	6,312	6,382
PSEG Power	2,538	2,788	2,906
PSEG Services Corporation	1,138	1,130	1,044
PSEG Energy Holdings	112	105	20
Grand Total	**9,857**	**10,335**	**10,352**

Source: Response to OC-98 (UPDATE)

As shown in the table above, the employee headcount of PSEG Energy Holdings decreased significantly from year end 2008 to year end 2009. This was caused by a transaction in which PSEG Energy Holdings on October 1, 2009, distributed the equity of PSEG Texas, LP to PSEG, which in turn distributed the equity to PSEG Power. The transaction was accounted for as a non-cash transfer of equity interest between entities under common control. PSEG Power had been operating PSEG Texas since January

2008 under a management agreement. After the transfer, the employees became PSEG Power employees.[2]

Organizational Division Between PSEG Service Company and PSE&G Legal Entities

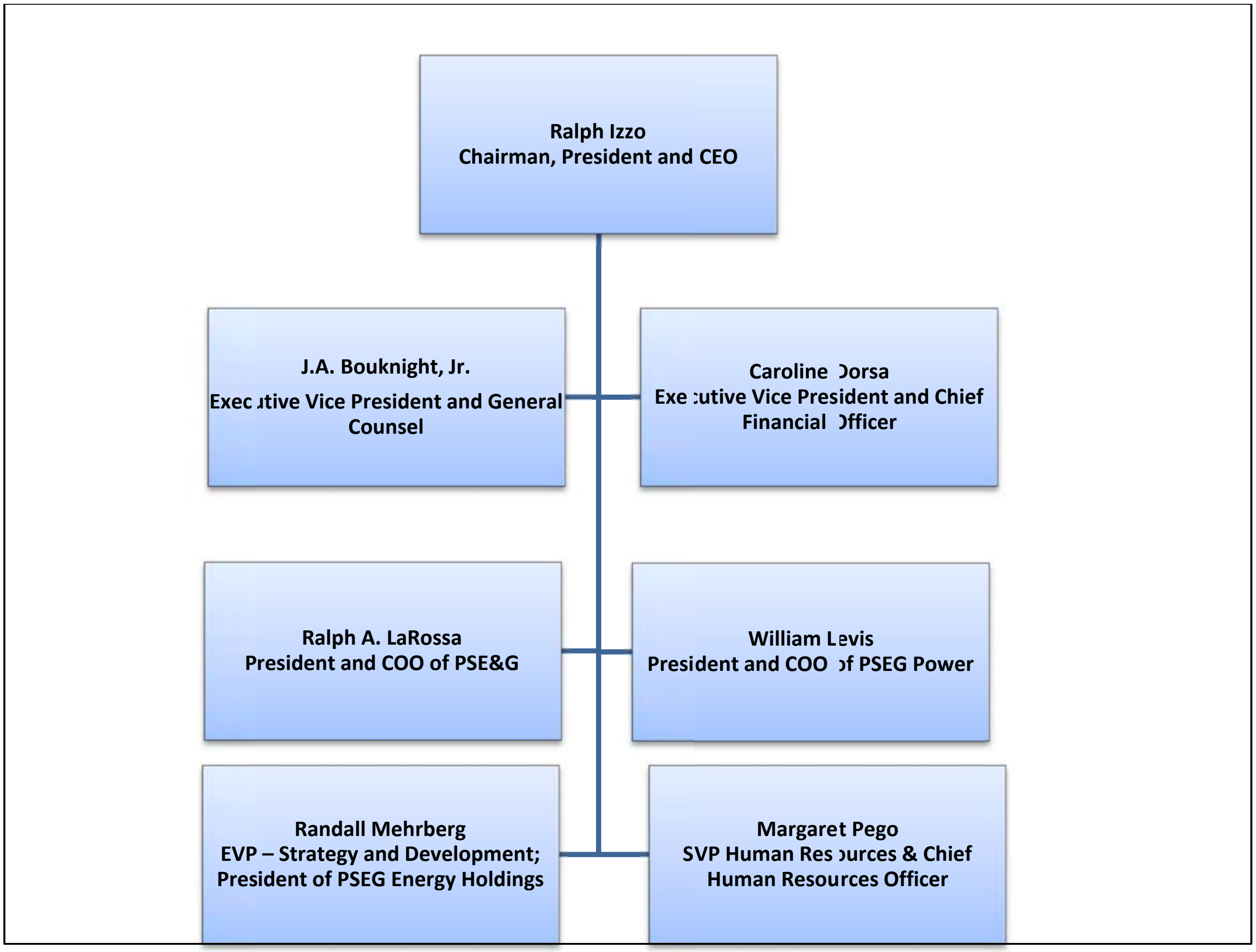
Public Service Electric & Gas operates as a separate entity, a regulated utility, serving customers across New Jersey. The head of the utility is Ralph A. LaRossa, President and Chief Operating Officer. Overland reviewed the variances in the employee headcount by cost center, focusing on significant variances, particularly from 2008 to 2009, and any explanations for those variances. The cause of most of the significant variances from 2008 to 2009 is due to the reorganization of Customer Operations. The reorganization was implemented by utilizing more temporary employees and less full time permanent employees. This allowed for flexibility in managing employees as the new customer system, iPower, was implemented. The 3034 cost center was created in 2008 as part of the establishment of the Delivery Projects and Construction. It supports the large electric transmission expansion projects, other large capital projects, and storm restoration efforts. PSE&G states that the hiring for this cost center is in line with staffing objectives. Cost center 3045 transferred utility finance employees from PSEG Services Corporation to PSE&G at the end of 2009.[3]

PSEG Incorporated Executive Management

Public Service Enterprise Group as a legal entity does not have any employees.[4] The senior executives are employed by PSEG Services Corporation. PSEG's executive management, as of April 2010, is summarized in the chart below.

[2] PSEG's 2009 10-K. http://www.sec.gov/Archives/edgar/data/81033/000119312510040508/d10k.htm
[3] Response to Discovery, OC-777.
[4] Response to Discovery OC-154.

Table 5-4 – PSEG's Executive Management



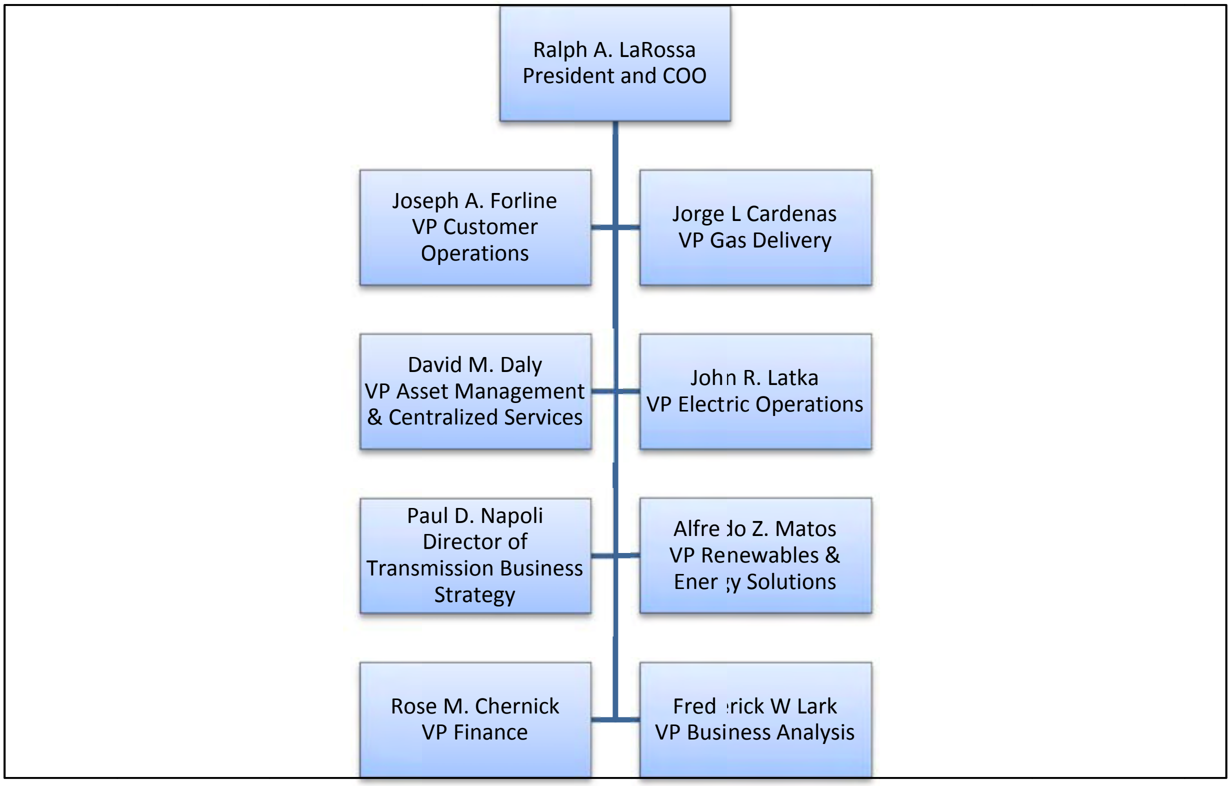
Source: Response to Discovery, OC-1270.

PSE&G Operations Management

As of April 2010, the President and Chief Operation Officer, Ralph LaRossa, was responsible for PSEG's Power Delivery Company, specifically, PSE&G. PSE&G is a regulated public utility company that transmits and distributes electricity and gas to nearly four million customers in New Jersey.[5] The top executives in PSE&G are summarized below.

[5] http://www.pseg.com/about/company_overview.jsp#anchor0

Table 5-5 – PSE&G Operations Management



Source: Response to Discovery, OC-1270.

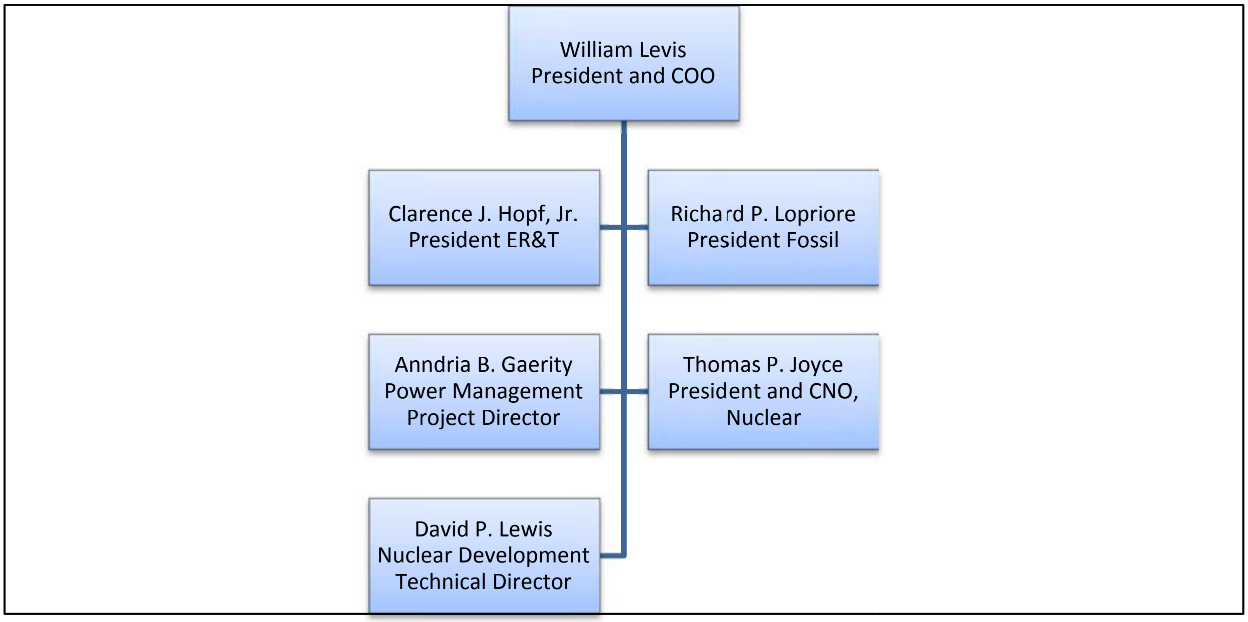
Other services that are offered by PSE&G include appliance services, commercial lighting sales, installation and maintenance, and reading and billing of meter for other utility companies or municipalities.

PSEG Power and Subsidiaries

PSEG Power supplies approximately 13,300 MW of electric energy to the Northeast and Mid-Atlantic states.[6] PSEG Power also has an energy trading function called PSEG Energy Resources & Trade, which "markets the output of PSEG Power's generation assets, acquires and hedges fuel and power, economically dispatches plants and trades numerous energy-related products".[7] As shown below, the head of this business segment is President & COO of PSEG Power, William Levis.

[6] http://www.pseg.com/about/company_overview.jsp#anchor1
[7] http://www.pseg.com/companies/resources_trade/about.jsp

Table 5-6 – PSEG Power



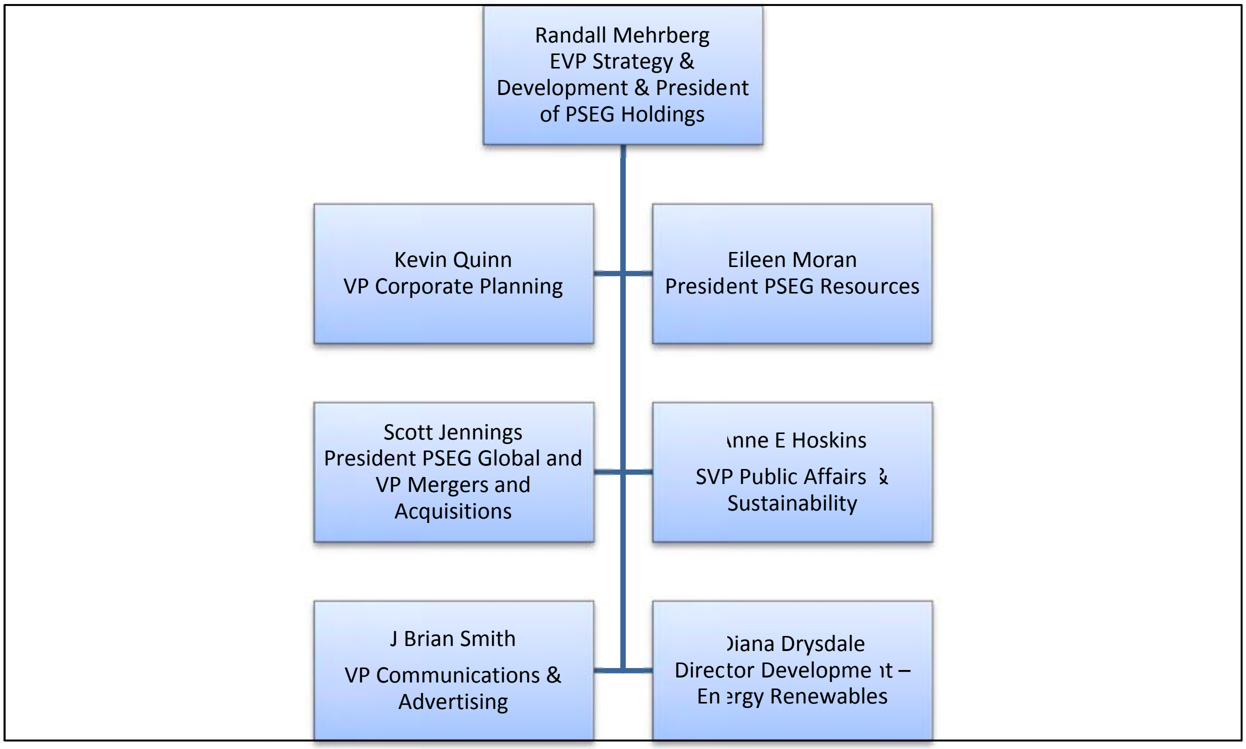
Source: Response to Discovery, OC-1270.

PSEG Energy Holdings

This subsidiary is a holding company for two unregulated organizations: PSEG Global and PSEG Resources. PSEG Global operates generation and distribution companies, mostly in the United States and Latin America. The prominent sub organizations within PSEG Global are: PSEG Solar Source, which designs, builds, owns, and operates large scale solar projects; Energy Storage and Power, LLC, which markets compressed air storage; and Garden State Offshore Energy, which is seeking to develop a windfarm off the coast of New Jersey. PSEG Resources maintains investments in energy-related financial transactions, most of which are leveraged lease investments.[8]

[8] http://www.pseg.com/companies/energy_hol/overview.jsp

Table 5-7 – PSEG Energy Holdings



Source: Response to Discovery, OC-1270.

Nuclear Operations

PSEG Nuclear has a controlling interest in and operates or oversees three separate nuclear power facilities. PSEG Nuclear owns 100% of the Hope Creek Generating Station and 57% of the Salem Generating Station in Salem County, New Jersey. Exelon owns the remaining interest in the Salem Generating Station. PSEG also owns 50% of the ownership interest in Peach Bottom Atomic Power Station in Delta, Pennsylvania. Exelon owns the remaining interest in Peach Bottom Power Station.

No PSEG affiliate has filed for a license to permit the construction of a new nuclear unit during the period under audit. Ralph Izzo, chairman, president and CEO of PSEG said, “I think the biggest impediment of aggressive nuclear technology is its cost.” PSEG is waiting for the first new reactors to be licensed and built before making any decision about new nuclear plants. Izzo added, “The cost is not within my comfort level right now.” In May 2010, a time subsequent to the period under audit, PSEG Nuclear filed an application for an Early Site Permit with the Nuclear Regulatory Commission for a fourth reactor at Artificial Island in Salem County.[9]

[9] Per discussion with Mally Becker, Assistant General Regulatory Counsel; confirmed by Internet article: http://www.nj.com/sunbeam-news/index.ssf/2011/07/nuclear_regulatory_commission.html

Upon the expiration of the useful lives of these nuclear facilities, there is a cost to decommission them in an environmentally safe manner. PSE&G devoted funds collected from ratepayers to the cost of completing the decommissioning in the future and placed those funds in an irrevocable external trust - Nuclear Decommissioning Trust Funds ("NDTF"). These funds were created at the time that the nuclear facilities were placed into service.

In 1999, the New Jersey Board of Public Utilities approved the transfer of PSE&G's ownership in the aforementioned nuclear facilities to an unregulated affiliate, PSEG Power. The following year, all liabilities and obligations, including the obligation to fund the decommissioning costs of the nuclear facilities, were assumed by PSEG Power. Along with the transfer of obligations, the balance of the NDTF was transferred to PSEG Power. In 2004, the BPU accepted a settlement on the nuclear decommissioning costs when it was agreed that the New Jersey ratepayers would no longer pay for nuclear decommissioning costs through a component of the societal benefit charge (SBC).

PSEG has continued to invest in its nuclear generation. In 2011, PSEG Power approved $192 million for a steam path retrofit and related upgrades for Peach Bottom Units 2 and 3. The Unit 3 upgrades were completed on schedule in October 2011, while the Unit 2 upgrades are scheduled to be completed in 2012. PSEG also plans to invest approximately $400 million to pursue additional power output through an extended power uprate of the Peach Bottom nuclear units. The uprate is expected to be in service in 2015 for Unit 2 and 2016 for Unit 3.[10]

[10] PSEG 2011 Third Quarter 10-Q Filed 11/1/11.

6. Executive Management and Corporate Governance

This Chapter addresses the activities of the Board of Directors and senior management in the oversight of PSEG and PSE&G operations. The Board and senior management compensation is also addressed along with Sarbanes Oxley compliance.

Summary of Findings

1. In the 2009 ISS (Institutional Shareholder Services) Corporate Governance Quotient, PSEG had the following areas for improvement in its corporate governance structure: There is no policy disclosure that limits the number of other boards the PSEG directors are allowed to serve on. The company does not conduct performance reviews of individual directors.

2. PSEG pays its board members a cash retainer and meeting fee that is in the second lowest quartile of their peer group.

3. PSEG grants equity shares to its board members with a value that is close to the 75th percentile of their peer group.

4. PSEG's total compensation for board and committee service is close to the 75th percentile of the peer group. In comments provided by PSE&G in its factual review of the Overland Audit Report, the Company represents the board and committee service compensation has, subsequent to the Mercer Study referenced by Overland, moved closer to the median relative to their peer group.

5. The Board is currently comprised of nine directors.

6. PSEG has seven standing committees of the Board of Directors. These committees are the Audit Committee, Corporate Governance Committee, Executive Committee, Finance Committee, Fossil Generation Operations Oversight Committee, Nuclear Generation Operations Oversight Committee, and Organization & Compensation Committee.

7. The PSEG Board has an informal committee member rotation process.

8. The PSEG Board has determined that it is in the company's best interest for one specific person to hold the three positions of President, Chairman of the Board and CEO.

9. PSEG undertakes succession planning for its key management positions.

10. Only five of the fifteen most senior positions at PSEG and PSE&G in November 2010 were judged to have either a "ready now" succession candidate or were in positions that would be realigned in a subsequent reorganization if a sudden vacancy occurred.

11. In administering the compensation program for executive officers and key employees, the Organization and Compensation Committee of the PSEG Board has historically retained an

outside advisor to consult it on executive compensation matters. Most recently, the committee has relied upon Compensation Advisory Partners to fill this role.

12. In designing its Executive Compensation Program, the Organization and Compensation Committee of the PSEG Board focused on total direct compensation for each executive rather than the individual components of compensation that consist of salary, targeted short-term incentive compensation, and targeted long-term incentive compensation. The company targeted the median of compensation of similar positions within an identified peer group of energy companies adjusted for performance and experience.

13. Compared to its peer group, PSEG's named executive officers were all expected to be compensated within a reasonable range of the competitive median in 2010.

14. PSEG executives' short- and long-term incentive compensation was highly dependent on the achievement of financial goals.

15. It is inappropriate to draw any definitive conclusions regarding the reasonableness of PSEG executive compensation with respect to other New Jersey utilities due to differences in the size of corporate operations as well as executive tenure and experience.

16. PSEG uses a governing document called "Business Conduct Compliance Program" to provide guidance in carrying out an effective ethics and compliance program.

17. PSEG employees (union and non-union) complete an annual integrity training program.

18. The PSEG Ethics and Compliance function has an Integrity Line where employees can disclose any observances or complaints regarding accounting, auditing, and internal control matters; any misappropriation of company assets or proprietary information; and any violation of company or government laws and regulations.

19. Neither PSEG nor PSE&G identified any material weaknesses in internal control over financial reporting as of December 31, 2008 or December 31, 2009. Deloitte & Touche LLP issued unqualified opinions on PSEG's internal control assessments for these two dates. The external auditors were not required to and they did not attest to the management reports on PSE&G.

20. We noted no instances of material Sarbanes-Oxley Act non-compliance in our review.

21. The PSEG Audit Committee Charter allows the Chair of the Audit Committee to pre-approve fees for any amount to the independent auditor as long as he or she reports the authorization at the next committee meeting.

Recommendations

1. Overland recommends the PSEG Corporate Governance Committee and the entire Board consider board member nominees who possess accounting and/or regulated utility executive experience when next adding to or replacing current members. We believe that the size of the

board should be increased by one or two members to improve the diversity of expertise on the board and to provide additional resources associated with Board responsibility.

2. The level of stock ownership required of Board members should be reviewed and brought more in line with peer group stock ownership policies.

3. Overland recommends that logs be kept by the Corporate Secretary of all Board and committee meeting minutes and all associated materials so that it can be periodically determined that the company's records are complete.

4. The President of PSE&G should be added to the PSE&G Board of Directors, consistent with general industry practice.

5. Especially for executives whose responsibilities extend to that of the utility, we recommend that the O&C Committee reassess the weightings it assigns to goals associated with short-term and long-term executive compensation so that executives are motivated and have more incentive to attain goals associated with customer satisfaction, safety, and reliability and to those goals which they have some semblance of control. In addition, the committee should consider requiring a certain level of accomplishment with respect to customer satisfaction, safety, and reliability before short-term and long-term incentive compensation is triggered.

6. Overland recommends the company consider setting a dollar cap on the delegation authority provided to the Chair of the Audit Committee for eligible products and services offered by the external auditor between regularly scheduled Audit Committee meetings.

PSEG and PSE&G Board of Directors[1]

The PSEG By-Laws state that the number of directors on the Board must be no less than three and no more than sixteen.[2] PSEG's Board of Directors consisted of nine members at the end of 2010.[3] In recent years, the size of the Board has fluctuated from eight to ten members.[4] When compared to similar companies, PSEG's board membership is considered smaller than average. Mercer, an independent consultant retained by the Corporate Governance Committee of PSEG's Board, found that the number of PSEG directors is below the 25th percentile compared to a peer group of companies. However, the same is not true of PSEG's Board committees. Participation on the Audit, Compensation, and Nominating/Governance Committees either approximates or is above the peer group median.[5]

[1] In addition to obtaining formal responses to data requests which are used to support our findings, Overland interviewed several members of the PSEG Board in connection with this audit review. Overland interviewed the Chairman of the BOD and the chairs of all of its standing committees. Six of the nine members of the PSEG BOD were interviewed as well as all four members of the PSE&G BOD. Each interview covered a broad range of subjects, but were primarily conducted to gain an understanding of the expertise of the members, as well as to elicit their views on major issues facing PSEG.

[2] Article 1 of the PSEG By-Laws.

[3] Response to Discovery, OC-14.

[4] Review of Corporate Governance Committee minutes.

[5] Response to Discovery, OC-93.

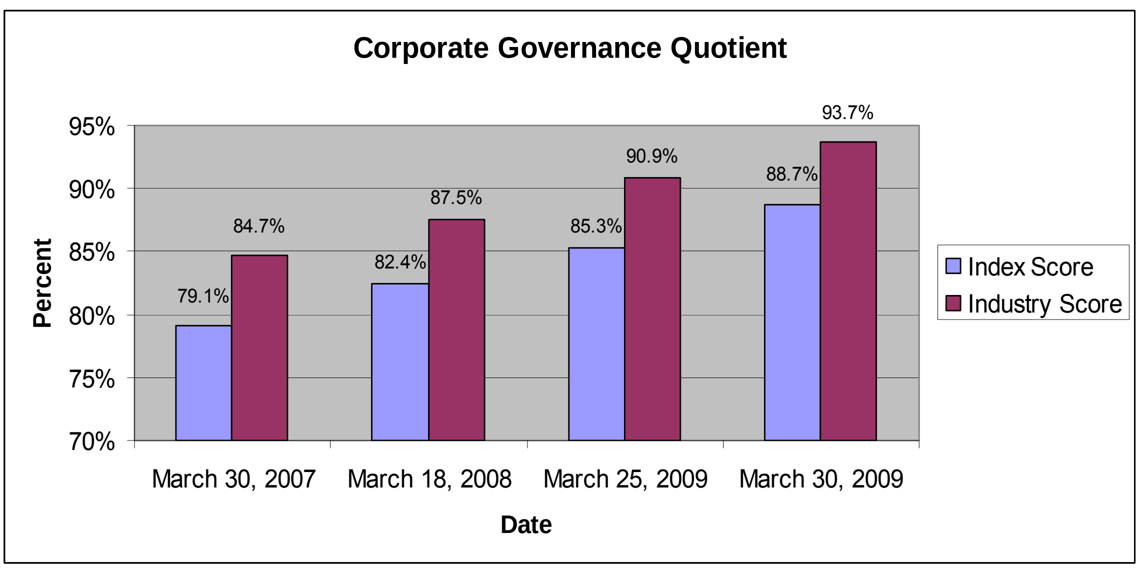
ISS provides shareholders advisory services, and has been in existence since 1985. In 2002, ISS developed a Corporate Governance Quotient (CGQ) a measure of corporate governance structures and practices relative to industry peers, as well as the overall market (measured by the S&P 500). The rating system was designed to assist institutional investors in evaluating the quality of corporate boards and the impact of their governance policies and procedures on corporate performance.

The CGQ is currently based on 65 ratings factors considered within eight core topics:[6]

- Board structure and composition
- Audit issues
- Charter & bylaw provisions
- Laws of the state of incorporation
- Executive and director compensation
- Progressive practices
- D&O stock ownership
- Director education

The following are the PSEG CGQ results since 2007, which represent the percentage of S&P 500 utility companies that PSEG outperformed as of the report date:

Table 6-1 – Corporate Governance Quotient



Source: Derived from response to OC-352

As shown in the graph above, PSEG has continually improved its corporate governance over the past three years when measured against the S&P 500 (index) and its utility peers (industry). The most recent

[6] http://www.riskmetrics.com/sites/default/files/CGQ_Criteria_US.pdf

ISS report also mentioned several positive aspects of PSEG's corporate governance as well as some areas to consider improving. Both categories are shown below:[7]

- Positive Aspects
  - The audit committee is entirely comprised of independent directors.
  - Only one inside director and no affiliated outsiders serve on the board.
  - Directors are subject to stock ownership guidelines.

- Areas for Improvement
  - There is no disclosure of a policy that limits the number of other boards the PSEG directors are allowed to serve on.
  - The company does not conduct performance reviews of individual directors.
  - PSEG directors can be elected by plurality vote.[8]

Selection and Retention of Board Members

According to the PSEG Corporate Governance Principles, the members of the Board of Directors of PSEG are selected based on their experience, qualifications, attributes, and skills as they address particular needs of the Board at any point in time.[9] Pursuant to New York Stock Exchange (NYSE) rules, the majority of PSEG's directors must be independent. The Board has established standards by which independence can be evaluated. These are enumerated in the company's Corporate Governance Principles.[10]

The Corporate Governance Committee is charged with identifying prospective candidates and recommending the candidates to the Board. This is done in one of two ways at PSEG. In the first method, the Board maintains a listing of potential future Board members. These potential members are categorized based on the skill set that they would bring to the Board. In the second method, the PSEG Board retains a search firm to help identify future board members.[11] Candidates typically meet and interview with the Lead Director, Chairman and any relevant Committee Chairs, during the selection process.[12] In uncontested elections, director nominees are elected for one-year terms by a majority of the votes cast by shareholders of PSEG's common stock.[13] The by-laws provide for up to 16 members to serve on the Board, although the actual size of the Board has never reached this level.[14]

[7] Response to Discovery OC-352; 3/30/09 ISS "Proxy Alert" report.

[8] In the response to OC-809, it is noted that an amendment was made to the company by-laws and corporate governance principles that states that in uncontested elections, directors must be elected by majority vote. This amendment to both documents was approved on November 17, 2009.

[9] Response to Discovery, OC-24.

[10] PSEG Proxy Statement filed March 8, 2010, p. 3.

[11] Interview with Corporate Governance Committee members.

[12] Ibid.

[13] PSEG Proxy Statement filed March 8, 2010, p. 13.

[14] By-Laws of Public Service Enterprise Group Incorporated as of November 17, 2009. Article I Section 1(a)

At the end of 2010, the tenure of members on PSEG's Board ranged from less than two years to over seventeen years.[15]

PSEG has a mandatory retirement age of 72 for Board members who are not employees of PSEG. Board members who are employees of PSEG may continue to serve beyond the age limit until the Annual Shareholder Meeting immediately following termination from active employment.[16] At the time of the March 2010 proxy statement, the oldest member of the Board of Directors was 69.

Composition of Subsidiary Boards

The members of the Board of Directors for PSEG and its subsidiaries are shown in the table below.[17] Unlike the other significant PSEG subsidiaries, the majority of directors for PSE&G are independent (three out of four). None of these subsidiary boards have standing committees:

[15] Response to Discovery, OC-14. Shirley Jackson has served on the PSEG Board in two separate stints – August 1, 1987 to May 1, 1995 and June 19, 2001 to present. The longest continuously serving Board member is Richard Swift who has served since December 20, 1994.

[16] Response to Discovery, OC-23.

[17] Response to Discovery, OC-14.

Table 6-2 – PSEG & Subsidiaries Board of Directors (12/31/09)

PSEG and Subsidiaries' Board of Directors as of 12/31/2009		
Public Service Enterprise Group	Ralph Izzo	PSEG Mgmt.
	Conrad Harper	Independent
	William Hickey	Independent
	Shirley Jackson	Independent
	Albert Gamper, Jr.	Independent
	David Lilley	Independent
	Thomas Renyi	Independent
	Hak Cheol Shin	Independent
	Richard Swift	Independent
Public Service Electric and Gas	Ralph Izzo	PSEG Mgmt.
	Albert Gamper, Jr.	Independent
	Conrad Harper	Independent
	Richard Swift	Independent
PSEG Services Corporation	Caroline Dorsa	PSEG Mgmt.
	Ralph Izzo	PSEG Mgmt.
	Ralph LaRossa	PSEG Mgmt.
	William Levis	PSEG Mgmt.
	Randall Mendenberg	PSEG Mgmt.
	Edwin Selover	PSEG Mgmt.
	Elbert Simpson	PSEG Mgmt.
PSEG Power LLC	Caroline Dorsa	PSEG Mgmt.
	Ralph Izzo	PSEG Mgmt.
	William Levis	PSEG Mgmt.
	Randall Mendenberg	PSEG Mgmt.
	Eileen Moran	PSEG Mgmt.
	Edwin Selover	PSEG Mgmt.
PSEG Energy Holdings	Caroline Dorsa	PSEG Mgmt.
	Ralph Izzo	PSEG Mgmt.
	William Levis	PSEG Mgmt.
	Randall Mendenberg	PSEG Mgmt.
	Eileen Moran	PSEG Mgmt.
	Edwin Selover	PSEG Mgmt.

Note: Edwin Selover retired effective January 8, 2010.
Source: Response to Discovery, OC-14; PSEG 2010 Proxy Statement; and Response to Discovery, OC-365

Notably, Ralph LaRossa, President and COO of PSE&G, is not a Director on the PSE&G Board. The presidents of the other two principal subsidiaries, however, are members of their respective Boards.

Board Diversity

According to the company's proxy statement, the Corporate Governance Committee considers the diversity of its nominees in the context of race, gender, national origin, background, experience, skills, accomplishments, financial expertise, professional interests, and personal qualities.[18]

In identifying candidates for inclusion on the board in recent years, the Corporate Governance Committee focused on individuals with particular backgrounds in manufacturing, operations, and engineering. One Organization & Compensation (O&C) Committee member suggested that a nominee with experience at a Fortune 100/200 company would be considered particularly attractive for inclusion on future boards.[19]

As summarized by the company, the independent directors on the current board have the following attributes:[20]

- Albert R. Gamper, Jr. – given his extensive management experience in the financial services industry, he provides valuable guidance to the company on matters such as capital structure, liquidity needs, and assessment of credit and other financial risks.

- Conrad K. Harper – as an attorney, he provides insight on matters related to regulation, government policy, and international investment.

- William V. Hickey – as the current President and CEO of a packaging products company, his contributions concerning corporate oversight and operational excellence are particularly valued. He also was a CFO at the same company and is a CPA.

- Shirley Ann Jackson – a distinguished scientist who was formerly the Chair of the Nuclear Regulatory Commission and is currently president of a private university. Her input on matters concerning public policy and scientific developments (particularly related to nuclear energy) are prized by the company.

- David Lilley – former Chairman, President and CEO of a global chemical and specialty materials company. He is looked to for leadership on matters concerning operations, safety, and environmental compliance.

- Thomas A. Renyi – former Chairman and CEO of a financial services company. In this position, he oversaw the successful implementation of two major mergers. He provides valuable insight on matters such as finance, oversight of a major enterprise, risk management, and operational excellence.

[18] PSEG Proxy Statement filed March 8, 2010 (p. 15).
[19] Interviews with members of the Board of Directors.
[20] PSEG Proxy Statement filed March 8, 2010 (pp. 16-17).

- Hak Cheol Shin – as a current executive at a multi-national conglomerate, he brings with him experience in technology, manufacturing, consumer products, and customer satisfaction.

- Richard J. Swift – a professional engineer who was Chairman, President and CEO of a global conglomerate focused on engineering, construction and power. He also was formerly the Chair of the Financial Accounting Standards Advisory Council. His experience compliments the generation and utility businesses of the company.

Refer to Attachment 6-1 for additional biographical and committee information on the Board members.

We generally found the PSEG Board of Directors to be comprised of an acceptable mix of expertise and experience relevant to oversight of corporate planning, reporting and operations. However, based on our interviews with various independent directors, it is evident that none of the current members have a detailed understanding of utility regulation or the ratemaking process. The Board is sensitive to its need to continually consider appropriate resources in light of changing business conditions, as well as the ongoing impact of succession planning.

Board independence is strong, and is supported by an experienced lead independent director. All of the members of the PSEG Board are independent, except its Chairman, Ralph Izzo.[21]

Despite Mr. Swift's participation on the Financial Accounting Standards Advisory Council between 2002 and 2006, none of the members of the current board of directors has recently been a practicing accountant.[22] The "financial expertise" required by the Sarbanes-Oxley Act of 2002 and the SEC is met by members of the PSEG Board through their experience of actively supervising financial positions in a company. In addition, as addressed above, none of the independent members of the current board of directors has a regulated utility background.

Given the complexity of and increased focus placed on financial reporting in recent years, the benefits of having a current or recently practicing accountant cannot be overstated. Additionally, PSEG's focus on the core businesses of generation, transmission and distribution would be complemented by the addition of a former utility executive who could bring considerable industry knowledge to the Board. When it considers a new addition to the Board, a person with regulated energy utility executive experience should be given priority consideration.

For these reasons, we recommend the PSEG Corporate Governance Committee and the entire board consider board member nominees who possess accounting and/or regulated utility experience when next adding or replacing future members.

[21] PSEG 2010 Proxy Statement

[22] Response to Discovery, OC-1371. Mr. Hickey is a CPA, but he has not been CFO of a company since the 1990's if not prior to that decade.

Board Compensation and Stock Ownership

Compensation - The following table reflects the compensation for the PSEG Board members for the period 2005 through 2009.

Table 6-3 – Board Member Compensation

Board Member Compensation					
Compensated Activities	2005	2006	2007	2008	2009
Annual Retainer	$50,000	$50,000	$45,000	$45,000	$45,000
Additional Audit Committee Annual Retainer	$5,000	$5,000	$5,000	$5,000	$5,000
Meeting Attendance	$1,500	$1,500	$1,500	$1,500	$1,500
Chairmanship of Audit Committee	$10,000	$10,000	$15,000	$15,000	$15,000
Chairmanship of Organization and Compensation Committee	$5,000	$5,000	$10,000	$10,000	$10,000
Chairmanship of Any Remaining Committee	$5,000	$5,000	$5,000	$5,000	$5,000
Lead Director				$15,000	$15,000
Source: PSEG Proxy Statement filings with the SEC from 2005-2009.					

The Corporate Governance Committee retains the services of outside consultants to provide information and advice on the level of compensation for the directors who are not executive officers. In June 2008, Mercer provided this service by sharing competitive compensation data for the PSEG peer group's outside directors and by advising on pay levels.[23] The peer group that Mercer utilized for the report was based on 2007 revenue and market capitalization. The table below shows these figures for the peer group as well as PSEG.

[23] Response to Discovery OC-19.

Table 6-4 – Mercer's Peer Group Financial Data [Begin Confidential]

Peer Company	Revenue (2007)	Market Cap (Dec 2007)
[redacted]		

[End Confidential]

Mercer issued a report on December 8, 2008 on the Review of Board of Directors Compensation. In comparison with a peer group of companies selected by Mercer, the consultants found the following concerning PSEG's director compensation:

- PSEG's retainer and per meeting fee for Board service is between the 25th percentile and median of the peer group

Table 6-5 – General Board – Cash Compensation [Begin Confidential]

Peer Company	Revenue (2007)	General Board - Cash Compensation	
		Member Cash Retainer	Member Meeting Fee
[redacted]			

[End Confidential]

- The value of equity granted to its directors is close to the 75^{th} percentile of the peer group

Table 6-6 – General Board – Equity Compensation [Begin Confidential]

		General Board - Equity Compensation		
	Revenue	Member	Member	Annualized Total Equity
Peer Company	(2007)	Initial Equity	Annual Equity	Value
[redacted]				

[End Confidential]

- Total compensation for Board and Committee service is approximately in the 75th percentile of the peer group.[24]

[24] Response to Discovery, OC-93.

Table 6-7 – Committee – Total Direct Compensation [Begin Confidential]

Peer Company	Revenue (2007)	Committee - Total Direct Compensation		
		Member of Comp & Gov. Committees	Comp Committee Chair and Member of Gov. Committee	Audit Committee Chair and Member of Gov. Committee
[redacted]				

[End Confidential]

Stock Ownership - Each director is required to own at least 4,000 shares of PSEG common stock within three years after his/her election to the Board.[25] Of the companies listed in PSEG's peer group according to their 2008 Proxy Statement, this requirement appears to be on the lower end of the stock ownership requirement for the directors of the peer group companies. The peer group's stock ownership requirements for its non-employee directors are listed below:[26]

- American Electric Power Company, Inc. – must defer $120,000 annually until the termination of service as a director
- Consolidated Edison, Inc. – three times the annual director retainer
- Constellation Energy Group, Inc. – five times the annual cash retainer within five years of appointment to the Board
- Dominion Resources, Inc. – lesser of 12,000 shares or five times the annual retainer within four years of election to the Board
- Duke Energy Corporation – five times the annual cash retainer
- Edison International – four times the annual retainer within five years

[25] http://www.pseg.com/investor/governance/pdf/principles.pdf
[26] Obtained from either the company's website or most recent SEC Filings (10-K or Proxy Statement)

- Entergy Corporation – four times the annual cash retainer within three years of election to the Board
- Exelon Corporation – 5,000 shares within five years of election to the Board
- FirstEnergy Corporation – 100 shares at the time of election and five times the annual equity retainer within five years of election to the Board.
- FPL Group, Inc. – three times the annual cash retainer within three years
- PG&E Corporation – $200,000 within five years of election to the Board
- PPL Corporation – five times the annual cash retainer fee as of the fifth year of Board service
- Progress Energy, Inc. – acquire beneficial interest in first year; 1,000 shares by the end of the second year; and 5,000 by the end of the fifth year of service.
- Sempra Energy – four times the annual base retainer within five years of election to the Board
- The Southern Company – four times the annual retainer fee within five years of election to the Board
- Xcel Energy, Inc. – seven times the annual retainer within five years of election to the Board

The actual ownership levels for each of PSEG's board members in recent years are summarized in the following table:

Table 6-8 – PSEG Board of Directors Stock Ownership Summary

PSEG Board of Directors Stock Ownership Summary								
	2/19/07		2/15/08		2/20/09		2/19/10	
Director	Common Stock	Phantom Stock	Common Stock	Phantom Stock	Common Stock	Phantom Stock	Common Stock	Phantom Stock
Frank Cassidy	113,770							
Caroline Dorsa	6,732		13,560		18,467		33,964	
Robert J. Dougherty, Jr.	59,410							
Ernest Drew	14,390		29,131					
E. James Ferland	996,595		588,252					
Albert Gamper Jr.	7,567		15,282		21,758	16,741	25,523	19,060
Conrad Harper	10,853		21,932		27,022		30,920	
William Hickey	6,966		13,932		20,701	11,371	24,214	13,419
Ralph Izzo	351,806		1,017,222		741,932		979,914	
Shirley Ann Jackson	7,094		14,310		19,251		22,972	
Ralph LaRossa			92,827		41,125		81,438	
William Levis			197,500		124,375		159,594	
David Lilley					0		5,897	
Thomas O'Flynn	297,740		634,229		484,057			
Thomas Renyi	6,232		12,561		17,467	18,179	21,147	22,414
R. Edwin Selover			131,428		64,789			
Hak Cheol Shin					2,343		5,753	
Richard Swift	12,970		26,247		32,656	31,235	36,692	35,537
Sources: OC-29 and 2006-2009 Proxy Statement Schedule 14A filed with the SEC								

The PSEG Corporate Governance Principles allow for compensation that may include cash, common stock, or restricted stock. The principles also provide for reimbursement of all expenses for attending Board and Committee meetings and related functions.

PSEG Board Oversight of and Interaction with Management[27]

As with most boards, the PSEG Board of Directors provides direction and oversight to PSEG's management.

PSEG board and committee meetings are conducted subject to agendas, the contents of which are frequently set by the responsibilities and requirements documented in the applicable group charters. Directors and management work in concert to make sure that any emerging issues or topics of special interest are scheduled for discussion and addressed.

Pre-meeting information packages are generally sent to directors approximately one week in advance of the meeting. At the request of directors, these information packages have become more summarized and less voluminous in recent years. The consensus among directors is that these packages are sent on a timely basis and are adequate in scope and content.

Various members of management generally attend all board and committee meetings to make presentations and answer questions. Occasionally, management will attend dinners with board members on the night before meetings in a less formal setting. Prior to meetings, committee chairs will often meet with management to discuss meeting topics and the contents of information packages. Between meeting dates, management is accessible to board members on an as needed basis.

In months when meetings of the board and the various committees are not scheduled, management provides board members with updates that include a letter from Ralph Izzo summarizing developments since the last board meeting, recent financial analysts' reports on PSEG, a PSEG nuclear generation executive summary, a PSEG fossil generation executive summary, and any communications sent to generation employees.[28]

Overall, it appeared to us that the board struck the right balance between monitoring performance without substituting its own judgment for that of management's. Discussions with board members and management suggest that the two had a record of open communication. The board seemed satisfied with the information they were provided from company personnel.

When reviewing board and committee meeting minutes and associated materials, it was difficult at times to determine what information had been redacted and what material had been unintentionally withheld. On more than one occasion, we noted references in the minutes to materials that were not initially provided to us. In one instance, we identified committee meeting minutes which were missing

[27] Interviews with various members of the Board of Directors.
[28] Response to Discovery, OC-804.

from the company's official records, and only when we called the matter to the attention of the company were they made available for review.[29]

To improve the recordkeeping of the PSEG board and its committees, we recommend that a log be kept by the Corporate Secretary of all board and committee meeting minutes. A separate log should be kept of all pre-meeting materials, hand-outs, presentation materials, etc. for the board and each committee. This second log should list unique identifying characteristics (e.g., date, preparer, number of pages, etc.) of the materials. Both of these logs should be periodically compared to the meeting minutes and an official copy of the materials to ascertain whether records are complete. Deficiencies should be immediately corrected.

Review of Committee Structure

PSEG has seven standing committees of the Board of Directors. These committees are the Audit Committee, Corporate Governance Committee, Executive Committee, Finance Committee, Fossil Generation Operations Oversight Committee, Nuclear Generation Operations Oversight Committee, and Organization & Compensation Committee.[30]

During the audit period, on January 15, 2008, the Board of Directors created the Fossil Generation Operations Oversight Committee and Nuclear Generation Operations Oversight Committee. The Board believed the creation of these two committees would be better able to dedicate their time as evaluators and advisors for either nuclear or fossil generation-related matters; specifically the business operations and construction programs under PSEG Power LLC. Even though the Fossil Generation Operations Oversight Committee was new, the Nuclear Generation Operations Oversight Committee expanded the role and responsibilities of the concurrently dissolved Nuclear Committee by adding two members and adding new oversight and monitoring of: large construction projects, key performance indicators, current events in the nuclear industry, review of labor and human relations, and review of legal and compliance issues related to nuclear operations.[31]

The following table summarizes the number of meetings held by each committee between 2007 and 2009. For comparison purposes, we have also included the number of full Board meetings:

[29] Review of the Corporate Governance Committee meeting minutes. According to company personnel, because the acting secretary had not signed the minutes, they had been excluded from the official records.
[30] http://www.pseg.com/investor/governance/committees.jsp
[31] Response to Discovery OC-465.

Table 6-9 – PSEG Board of Directors' and Related Committees' Meeting Summary

PSEG Board of Directors' and Related Committees' Meeting Summary			
Description	2007	2008	2009
Number of meetings held by the Board	10	10	8
Number of committee meetings held:			
Audit Committee	8	9	8
Corporate Governance Committee	9	8	6
Executive Committee	0	0	0
Finance Committee	5	5	6
Fossil Generation Operations Oversight Committee	(A)	3	3
Nuclear Generation Operations Oversight Committee	(A)	3	3
Nuclear Committee	4	(A)	(A)
Organization & Compensation Committee	8	7	6

Sources: PSEG Proxy Statements filed March 5, 2008, March 16, 2009, and March 8, 2010.

(A) The Nuclear Committee was disbanded in early 2008. The two operations oversight committees were formed in early 2008.

Each board committee has different requirements regarding the number of members that can serve on the committee. The Audit Committee, Finance Committee, and Organization and Compensation Committee each must have at least three members. Currently, they have six, five and five members, respectively. The Fossil and Nuclear Generation Operations Oversight Committees each must have between three and six members. Currently, they each have six members. The Corporate Governance charter does not specify a number of required members. Currently, this committee has four members. The Executive committee is to be comprised of the Chairman of the Board and at least one additional independent director. Currently, the Executive Committee has four members. Each committee's purpose and responsibilities are outlined below.[32]

<u>Audit Committee</u> – the purpose of this committee is to assist the Board in fulfilling its responsibilities for oversight of the integrity of the company's financial statements and the quality and integrity of the accounting, auditing and financial reporting practices of the Corporation. The committee also assists the Board in its oversight of the company's compliance with legal and regulatory requirements and oversees the auditing process, both internal and external. This committee meets at least four times per year.

<u>Corporate Governance Committee</u> – the purpose of this committee is to monitor the composition of the Board to assure that it contains a reasonable balance of professional interests, business experience, financial expertise, diversity, and independent directors. This committee also assists the Board in administering the corporate governance practices of the Board and its committees. This committee meets at least twice per year.

[32] http://www.pseg.com/investor/governance/committees.jsp

Executive Committee – the purpose of this committee is to exercise the full authority of the Board of Directors when the Board is not in session and is not able to convene.

Finance Committee – the purpose of this committee is to review and make recommendations to the Board of Directors regarding corporate financial policies and processes and significant financial decisions. This committee meets at least three times per year.

Fossil Generation Operations Oversight Committee – the purpose of this committee is to provide the Board with an independent basis for evaluating the safety and effectiveness of the fossil generation operations of PSEG Fossil LLC and PSEG Energy Holdings. This committee meets at least three times per year.

Nuclear Generation Operations Oversight Committee – the purpose of this committee is to provide the Board with an independent basis for evaluating the safety and effectiveness of the nuclear generation operations of PSEG Nuclear LLC. This committee meets at least three times per year.

Organization and Compensation Committee – the purpose of this committee is to assist the Board in fulfilling its responsibilities relating to the compensation of the Corporation's executive officers and key employees, succession planning and evaluating the performance of the Chief Executive Officer. This committee meets at least twice per year.

To help achieve the objectives set forth above, the Committees have certain authorities granted to them by the Board:

Audit Committee – the committee is directly responsible for the appointment, termination, compensation and oversight of the work of the independent auditor of the company. The Committee shall, at least annually, obtain and review a report by the independent auditor describing the firm's internal quality control procedures, any material issues or inquiries raised by a review of those procedures and any steps taken to address such issues and inquiries. The independent auditor shall report directly to the Audit Committee. The Committee also prepares the Audit Committee Report for inclusion in the company's proxy statement.

Corporate Governance Committee – the committee has the authority to retain and terminate such consultants as the Committee deems appropriate, to identify director candidates, to make recommendations for director compensation, review the performance of such consultants on an annual basis, and approve the consultants' fees and other retention terms.

Executive Committee, Finance Committee, Fossil Generation Operations Oversight Committee, and Nuclear Generation Operations Oversight Committee – these committees have the authority to retain appropriate resources to assist them in discharging their responsibilities.

Organization and Compensation Committee – the committee has the authority to retain, terminate, and approve fees and terms for independent compensation consultants to assist it in designing compensation programs that are consistent with comparable industry practices.

As a company whose stock is traded on the NYSE, NYSE rules dictate the existence of several of PSEG's committees such as the Audit Committee, the Corporate Governance Committee, and the Organization and Compensation Committee.[33] However, the decision to establish other committees is left to the Board's discretion. The following table compares PSEG's committee structure to that of a peer group:[34]

Table 6-10 – Board Committee Structures

Board Committee Structures 2009										
Company	Audit	Corp Gov	Exec	Finance	Ops Over-sight	Org & Comp	Policy	Env, Health, Safety	Planning	Risk Over-sight
PSEG	x	x	x	x	x	x				
American Electric Power	x	x	x	x	x	x	x			
Consolidated Edison	x	x	x	x	x	x		x	x	
Constellation	x	x	x		x	x				
Dominion Resources	x	(A)		(B)		(A)				
Duke Energy	x	x		(B)	x	x				
Edison International	x	x		x		x				
Entergy	x	x	x	x	x	x				
Exelon	x	x			x	x				x
FirstEnergy	x	x		x	x	x				
FPL Group	x	x	x	x	x	x				
PG&E	x	x	x	x		x	x			
PPL	x	(A)	x	x	x	(A)				
Progress Energy	x	x	x	x	x	x				
Sempra	x	x	x			x		(C)		
Southern Company	x	x		x	x	x				
Xcel	x	(A)		x	(D)	(A)		(D)		

Sources: Proxy statements filed in 2010 for applicable companies.
Note: Committees were grouped above by primary responsibilities. Official titles used by PSEG or other companies may be slightly different.
(A) Combined Compensation and Governance committee.
(B) Finance and Risk Oversight/Management.
(C) Environmental and Technology.
(D) Combined Nuclear, Environmental, and Safety.

[33] NYSE Rules: Section 303A.
[34] Used the same peer group recently employed by the Board to determine the adequacy of its pay.

As shown in the preceding table, the committee structure adopted by PSEG is typical of other large utility holding companies.

Committee Rotation Process

The PSEG Board of Directors has an informal committee rotation process. The chairs of the aforementioned committees of the PSEG Board of Directors are expected to serve four years in that capacity with the potential of serving an additional twelve months if approved by the majority of the directors.[35] However, there is no specific limit to the number of years that a member can serve on a committee.[36] Based on a review of proxy materials of a peer group of companies, we found that mandatory rotation of directors between committees was not common industry practice.[37]

Use of Third Party Experts

Among the third parties retained by the Board or its committees during the period under review were the external auditor, Deloitte & Touche LLC, two different compensation consultants, and a search firm. In June 2008, the Organization and Compensation Committee retained the consulting firm, Mercer, "to provide general advice relating to all aspects of executive compensation, including the review of our current compensation programs and levels, the mix of base salary, equity, incentive and other payments, benefit plans, provision of comparative industry trends and peer data and the recommendation of program and pay level changes."[38]

As of June 2009, the Organization and Compensation Committee retained the services of Compensation Advisory Partners, to replace Mercer as the executive compensation consultant.[39] The key personnel of Compensation Advisory Partners were former members of Mercer.[40]

From June 2007 through September 2007, Spencer Stuart was retained to "identify potential candidates for nomination for election as a new independent director to the Board of Directors of PSEG." Fees paid to Spencer Stuart in 2007 totaled $135,522.[41]

Board of Directors Training

For new Board members, the Office of the Corporate Secretary provides an Orientation Booklet that provides an overview of PSEG and its affiliates. Some additional topics in the orientation booklet are: PSEG Practices and Principles, PSEG's most recent SEC filings, director compensation, a listing of the executive officer group and PSEG Board and Committee calendars. New Board members are also given

[35] PSEG 2010 Proxy Statement.
[36] Interview with Corporate Governance Committee members.
[37] Used the same peer group recently employed by the Board to determine the adequacy of its pay.
[38] Response to Discovery, OC-19.
[39] Ibid.
[40] Organization and Compensation Committee minutes dated September 15, 2009.
[41] Response to Discovery, OC-19.

a tour of PSEG's facilities (i.e. power generating stations, ER&T trading floor and utility operation centers) as part of their orientation.[42]

The PSEG Board of Directors also has a continuing education program for its existing Board members. In addition to touring PSEG sites and facilities along with the new Board members, current Board members receive committee-specific training. Management of PSEG's subsidiary operating companies provide verbal reports to the Board members educating them on the current issues and operating activities for their respective operating companies. Board members receive status updates regarding the five-year business plan for the company. They also receive monthly mailings that include white papers and briefings from PSEG executives on current topics or issues. Finally, the Board brings in guest speakers from time to time to present on current global or macroeconomic topics.[43]

During Overland's interview with members of the Board, we were informed director education at PSEG has increased in the past few years. However, directors have expressed their opinions that the information could be streamlined to make reading and understanding it more efficient. At least one Board member also mentioned that it is expected that a Director will attend one or more educational presentations each year.[44]

Separation of CEO and Chairman Duties[45]

According to the company, the Board (based on advice from its Corporate Governance Committee) uses its collective members' experience and knowledge to establish the most effective form of organization. This specifically includes determining whether one or more persons should hold the title of Chairman of the Board, President and CEO.

At present, the Board has determined that it is in the company's best interest for one specific person to hold all three positions – Ralph Izzo. The Board believes that Mr. Izzo possesses the necessary ". . . experience, judgment, vision, managerial skill and overall leadership ability essential for the [company's] continued success."

This leadership structure adopted by the Board is complemented by the contributions of an independent Lead Director. While this position is designed to act as liaison between the CEO and other independent directors on various administrative matters, most importantly, it serves as an integral component in the system of checks and balances concerning corporate governance. In this latter role, the Lead Director provides a viewpoint that is independent and therefore may provide a different view in contrast to management perspectives.

[42] Ibid.
[43] Ibid.
[44] Interviews with Corporate Governance Committee members.
[45] PSEG Proxy Statement filed March 8, 2010, p. 4.

Senior Management

PSEG Executives - Senior Officers

PSEG and its subsidiaries are governed by a select group of senior officers, who generally constitute what PSEG designates as the Executive Officer Group ("EOG").

This group meets on a regular basis to review corporate operations and determine corporate policy. Members of senior management also participate in recurring meetings to review various aspects of corporate operations and financial results.

As of March 2010, this group of senior officers was comprised of: Mr. Ralph Izzo, Chairman, President, and CEO; Ms. Caroline Dorsa, EVP and CFO; Mr. J.A. "Lon" Bouknight, Jr., EVP and General Counsel; Mr. Randall E. Mehrberg, EVP – Strategy and Development; plus the presidents of PSEG Power, PSEG Energy Holdings, PSE&G, and PSEG Services Corporation.[46]

As referenced above, the EOG meets regularly to report on and discuss policies, initiatives, issues, and developments pertaining to the economics, operations, and business objectives of the subsidiaries and the enterprise generally. During the term of this audit, the members of this group were as follows:[47]

- J.A. "Lon" Bouknight, Jr., EVP and General Counsel
- Caroline Dorsa, EVP and CFO
- Clarence J. Hopf, Jr., President of PSEG Energy Resources & Trade
- Ralph Izzo, Chairman, President, and CEO
- Thomas P. Joyce, President and Chief Nuclear Officer of PSEG Nuclear
- Ralph A. LaRossa, President and Chief Operating Officer of PSE&G
- William Levis, President of PSEG Power
- Richard Lopriore, President of PSEG Fossil
- Randall E. Mehrberg, EVP – Strategy and Development
- Margaret M. Pego, SVP – Human Resources

See Attachment 6-2 for the biographies of these and other executives of PSEG and its subsidiaries.

Succession Planning

Succession planning focuses on identifying key management positions and assessing and developing talent for those positions. This process includes Executive Management positions and each position is reviewed by the Executive Officer Group in November of each year. The process is outlined below:

- "Succession Planning is conducted annually by management with periodic updates during the year.

[46] Response to Discovery, OC-95.
[47] Response to Discovery, OC-355.

- The starting point for succession planning is the 9-box talent assessment conducted for employees in grade levels 8 and above. Employees are assessed by their management teams in terms of leadership potential and current performance.
- Positions for succession planning are identified as those at or above director-level and other critical positions below director-level.
- Management creates succession plans using the 9-box talent assessment data. Possible successors are identified by name and readiness level using the timeframes Ready Now, Ready in 1-2 years, or Ready in 3-5 years.
- For successors not yet Ready Now, there is development planning to address the steps needed for the successor to become Ready Now for the position."[48]

The Human Resources Department updated the form used for succession planning in early 2010. The purpose of the update was to increase the percentage of potential successors classified as "ready now" for positions deemed critical by PSEG. This change was accomplished by providing a more structured and thorough development planning tool.[49]

Of the fifteen positions of senior vice president and above at PSEG and PSE&G in November 2010, only five were judged as having a "ready now" succession candidate or were positions that could be realigned in a subsequent reorganization. The other ten positions have at least one internal candidate to temporarily fill a vacancy in the case of an emergency.[50]

Term Sheets and Offer Letters for Senior Executives

PSEG only offers a term sheet for the Chief Executive Officer (CEO).[51] Overland reviewed the 2009 term sheet for the current CEO, Ralph Izzo, and found it to be reasonable compared to industry standards. Overland also reviewed the offer letter for CFO, Caroline Dorsa, along with her Non-Compete/Non-Solicitation Agreement[52] and found it to be reasonable compared to industry standards.

Executive Compensation

The following is an overview of PSEG executive compensation and should be read in conjunction with our discussion of various executive compensation matters in the Human Resources chapter found elsewhere in this report.

The goal of PSEG's Executive Compensation Program is to "attract, motivate and retain high-performing executives who are critical to [the company's] long-term success." The company attempts to achieve this goal by compensating such executives at the "median of compensation of similar positions within an identified peer group of energy companies. . ." adjusted for individual performance and experience as

[48] Response to Discovery, OC-132
[49] Response to Discovery, OC-772
[50] Response to Discovery, OC-1372.
[51] Response to Discovery, OC-308
[52] Ibid.

well as business results.[53] In designing its Executive Compensation Program, the Organization and Compensation (O&C) Committee focuses on total direct compensation (Salary PLUS Short-Term Incentive Compensation Target PLUS Long-Term Incentive Compensation Target) rather than the individual components of compensation for each executive.[54] These three elements and several others listed below make up the total package that is offered to most executives and key employees as disclosed in the company's 2010 proxy statement:[55]

- Base Salary
- Annual Cash Incentive (a.k.a. short-term incentive compensation)
- Long-Term Incentive
- Retirement Plans (e.g., defined benefit pension plans and 401(k))
- Deferred Compensation Plan
- Supplemental Executive Plan
- Post-Employment Benefits (e.g., severance and change-in-control benefits)
- Other Benefits (health care programs and limited perquisites)

According to company personnel, each component of compensation listed above is not necessarily offered to all "executives." For instance, there are three to four times the number of participants in the Long-Term Incentive Plan as there are for either of the two short-term incentive plans devoted exclusively to executives.[56] However, for most senior executives, the weighting of their compensation in 2008 was as follows:

Table 6-11 - Composition of Compensation for Named Executive Officers - 2008

Composition of Executive Compensation for Named Executive Officers 2008	
Description	Weighting
Base Salary	21.3%
Short-Term Incentive Compensation	16.8%
Long-Term Incentive Compensation (A)	42.3%
Change in Pension Value of Retirement and Supplemental Executive Plans PLUS 401(k) Company Contribution	12.7%
Deferred Compensation Plan (B)	0.2%
Other Benefits (C)	6.7%
Total	100.0%

Source: Derived from named executive officer summary compensation information disclosed in the PSEG Proxy Statement filed March 16, 2009.
Note: 2008 data was used instead of 2009 data because 2009 data included a number of non-recurring items related to executive turnover.
(A) Includes both stock and option awards
(B) Interest earned, to the extent it exceeds 120% of the applicable long-term rate
(C) Over half of this amount is due to relocation expenses incurred by the President and COO of Power.

[53] PSEG Proxy Statement filed March 8, 2010 (p. 22).
[54] O&C Committee minutes dated February 19, 2008.
[55] PSEG Proxy Statement filed March 10, 2010 (p. 25).
[56] Interview with Margaret Pego, PSEG Senior Vice President – Human Resources and Chief Human Resources Officer, on August 5, 2010.

As demonstrated in the preceding table, salary and incentive compensation (short-term and long-term) make up the vast majority of senior executives' pay. Coupled with the fact that the O&C Committee places emphasis on these components of compensation when designing an Executive Compensation Program, they will be the focus of our following discussion in Chapter 23.

Base Salary

In setting and assessing the appropriateness of the base salary for executives, the CEO and O&C Committee consider several sources of data. First, the company relies upon a third party, Towers Watson, to provide it salary survey data on both executive and non-executive positions. For executives, national data is used while regional data is used for lower-level positions.[57] Using this data and in consultation with the PSEG Human Resources Department, the CEO recommends the base salary levels for his direct reports to the O&C Committee. Appropriate levels of management do the same for other executives that do not report directly to the CEO.

The O&C Committee retains a separate, independent consultant to advise it on various matters, including the reasonableness of executive compensation. The consulting firm used by the committee has changed several times in recent years but is currently Compensation Advisory Partners, LLC (CAP). Among other things, CAP provides the O&C Committee with an evaluation of the competitive positioning of senior executive compensation relative to the company's selected peer group. (More details of the 16-company peer group as well as other information regarding executive compensation can be found in our discussion of Human Resources.)

As disclosed to us, underlying independent evaluations of the adequacy of base salary or any component of compensation for executives were limited.[58] To the extent the company disclosed base salary comparisons to its peer group, two of five senior executives were below benchmark levels, and three of five were above those levels for the year 2010. However, of these five, only the CEO's base salary was significantly different from the competitive median (78%). The same was true in 2009.[59]

Mr. Izzo's base pay is below that of PSEG's peers for the following reasons. When Mr. Izzo was first promoted to CEO in April of 2007, his salary was set below the median because of his lack of tenure and experience. In subsequent years (both at the end of 2008 and 2009), Mr. Izzo volunteered to forego an increase to bring his base pay closer to median levels because of the challenging economic

[57] Response to Discovery, OC-1306 and PSEG Proxy Statement filed March 10, 2010 (p. 29).

[58] Materials discussed and reviewed at O&C Committee meetings were frequently redacted. In response to a request of copies ". . . of all internal and external reports relied upon by the PSEG Organization and Compensation Committee to establish, to design, or to determine the reasonableness of executive compensation from January 1, 2007 to present", we were provided no reports from CAP and only two from CAP's immediate predecessor (OC-31).

[59] PSEG Proxy Statement filed March 8, 2010 (p. 27).

environment.[60] Members of the board of directors are fully aware that efforts to contain expenditures in difficult times must be balanced with the need to retain executive talent.[61]

Short-Term Incentive Compensation

Short-term incentive compensation is paid in cash each year if warranted by performance. For executives, short-term incentive compensation is paid from one of two plans – the Senior Management Incentive Compensation Plan (SMICP) or the Management Incentive Compensation Plan (MICP). While the two plans share many similar traits, the former is only open to senior vice presidents and above.[62]

In both 2008 and 2009, short-term incentive compensation was calculated as a percentage of an executive's base salary. Senior executives of PSEG are eligible to earn a higher percentage of their base salary in short-term compensation than lower-level executives. For instance, in 2009, the CEO was eligible to earn 131.6% of base salary if performance targets were met while some other executives were limited to only **[Begin Confidential]** **[End Confidential]** under the same circumstances.[63]

The remaining computation of PSEG's short-term executive incentive compensation changed between 2008 and 2009. One of the consequences of this change was a decrease in the potential variability of short-term incentive compensation from year to year. In 2008, if PSEG's return on equity (ROE) was not at least 95% of a peer group median, none of the executives would be paid any short-term incentive compensation unless a discretionary adjustment was made. Beginning in 2009, relative ROE was replaced by corporate performance against pre-determined earnings per share goals, and a failure to meet this goal no longer penalized executives with a forfeiture of all short-term incentive compensation. Rather, the EPS goal was but one of many goals that were all weighted to determine a total short-term compensation amount. [64]

Besides the change in and application of the "corporate" factor/goal, the other modifications adopted by PSEG for the short-term executive compensation plan between 2008 and 2009 <u>appear</u> to be largely cosmetic. Individual and business/employer performance in 2008 was replaced with individual, business unit earnings, and business unit scorecard performance. In response to data requests on the short-term incentive plans, the references to the types of executive goals are identical (corporate, financial, operational, and strategic).[65] However, we were not privy to many of the underlying computations for individuals, so it is possible that changes made to the plans were more substantial than they initially appear.

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[60] PSEG Proxy Statements filed March 5, 2008 (p. 20) and March 8, 2010 (p. 28).
[61] Interviews with various members of the board of directors.
[62] O&C Committee meeting minutes dated September 22, 2008.
[63] PSEG Proxy Statement filed March 8, 2010 (p. 32) and response to Discovery, OC-456 (Restricted).
[64] PSEG Proxy Statements filed March 16, 2009 (pp. 21-24) and filed March 8, 2010 (pp. 29-32).
[65] Responses to Discovery, OC-455 and OC-456.

Using the data to which we do have access, it is clear that performance metrics used in short-term executive compensation are skewed towards financial goals. Corporate and business unit earnings receive the lion's share of weight as demonstrated in the following table:

[Begin Confidential]

Table 6-12 – Short Term Incentive Compensation Weightings For Selected Executives

Short-Term Incentive Compensation Weightings For Selected Executives 2009						
		Weighting				
Name	Title	Corporate EPS	Business Unit Earnings	Financial Sub-Total	Other (A)	Total
[redacted]						

[End Confidential]

As disclosed in its 2010 proxy statement, the level of PSEG's targeted short-term incentive compensation for four of its five named executive officers is comparable to that of its peers.[66] Mr. Izzo's targeted short-term incentive compensation is higher than the company's peer group by design. The O&C Committee made the decision to target a higher level of short-term incentive compensation for Mr. Izzo to partially make up the lower-than-average Base Salary that he volunteered to receive.

[Begin Confidential]

[66] PSEG Proxy Statement filed March 8, 2010 (p. 27). While short-term incentive compensation is not disclosed separately, it can be derived by comparing the reported Base Salary and Total Cash Compensation amounts. Since the difference between these two is short-term incentive compensation, it is only reasonable to conclude that immaterial changes to PSEG's reported "% of Comparative Benchmark Levels" between Base Salary and Total Cash Compensation is caused by similar levels of short-term incentive compensation.

[67] Response to Discovery, OC-455 (Restricted).

[End Confidential][68]

While the SMICP and MICP are formula-driven, the plans do allow for discretionary adjustments. **[Begin Confidential]**

[End Confidential][69]

Long-Term Incentive Compensation

Pursuant to the Long-Term Incentive Plan (LTIP) approved by shareholders in 2004, executives and other key employees are eligible to receive equity awards that are designed to attract and retain qualified personnel, to motivate participants to achieve goals, and to align participants' interests with those of shareholders. To permit flexibility, the equity awards can be in the form of performance units, stock options, restricted stock, and restricted stock units. At the end of 2008 and 2009, the company used a 50/50 split of performance units and non-qualified stock options for its most senior officers.

Grant levels are determined by the O&C Committee. In setting these levels, the Committee considers the value of long-term incentive awards made by peers to executives in similar positions.[70] **[Begin Confidential]**

[End Confidential][71]

In previous years, performance shares/units were based on PSEG's performance with respect to total shareholder return and ROE relative to a peer group. The O&C Committee modified these performance metrics beginning in late 2008 at the recommendation of its compensation consultant. Relative total shareholder return was retained, but relative ROE was replaced with performance against a pre-determined, three-year average goal of return on invested capital. Each of these two metrics was given equal weight. The most recently reported goal for return on invested capital was 9.7%.[72]

Stock options awarded under the LTIP vest proportionately over a 4-year period.[73]

Conclusion Regarding the Significant Components of Executive Compensation

Given that investor expectations of future corporate earnings is the primary and most fundamental component driving total shareholder return, PSEG executives' short- and long-term incentive compensation is highly dependent on the achievement of financial goals. While the weightings of the

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[68] Response to Discovery, OC-456 (Restricted).
[69] Derived from response to Discovery, OC-461 (Restricted).
[70] PSEG Proxy Statement filed March 8, 2010 (p. 33)
[71] Response to Discovery, OC-455 (Restricted).
[72] PSEG Proxy Statements filed March 5, 2008 (p. 24) and filed March 8, 2010 (p. 34).
[73] PSEG Proxy Statement filed March 8, 2010 (p. 33).

short- and long-term incentive plans may align PSEG executives' financial interests with that of its shareholders, it raises the question whether or not other non-financial goals receive the appropriate level of attention. When there is disproportionately little incentive to achieve a goal or little disincentive in failing, management's focus may shift elsewhere. While we noted no egregious examples of PSEG management ignoring or giving little consideration to matters such as utility customer satisfaction, system safety, reliability, and other non-financial matters, it is important that there be a healthy balance between the goals to which the company aspires and the incentives it offers to attain them.

We also noted in at least one instance a disconnect between the performance over which an executive has some control and the performance on which his incentive is based. In 2009, 60 percent of the PSE&G President and COO's short-term incentive compensation was based on *PSEG's* earnings per share results (see the above table). In 2009, PSE&G contributed only 20 percent of PSEG's earnings while the generation affiliate (Power) contributed nearly 75 percent.[74] With Power's earnings dwarfing PSE&G's by roughly 4 to 1, Mr. LaRossa had little opportunity to control a significant portion of his own short-term incentive compensation. He had to rely disproportionately on Power to deliver better-than-expected results. Otherwise, his best efforts would be largely rendered moot.

Especially for executives whose responsibilities extend to that of the utility, we recommend several enhancements to the executive incentive compensation design. One, the O&C Committee should reassess the weightings it assigns to goals associated with short-term and long-term executive compensation so that executives are motivated and have more incentive to attain goals associated with customer satisfaction, safety, and reliability and to those goals which they have some semblance of control. Another possible consideration should be to design short- and long-term executive incentive plans in such a way that customer satisfaction, safety, and reliability goals must be met before compensation under one or both plans is triggered. The same approach was taken by the O&C Committee prior to 2009 when the pay-out of short-term incentive compensation to executives only occurred if ROE was at least 95 percent of a peer group median. This would help encourage management to maintain basic levels of service before they are rewarded with additional compensation.

Overall Design of PSEG Executive Compensation

PSEG's executive compensation is designed so that senior executives are targeted to earn most of their pay through performance. We also observed that the most senior executives had more pay at risk than junior executives. **[Begin Confidential]**

[End Confidential][75] In addition, the more senior an executive is in the organization, the more his/her pay is oriented towards long-term compensation.[76] This overall approach is consistent with other companies that we have reviewed.

[74] Derived from 2009 PSEG Form 10-K (p. 2).
[75] Response to Discovery, OC-456 (Restricted).
[76] PSEG Proxy Statement filed March 8, 2010 (p. 27).

Compared to its peer group, PSEG's named executive officers were all expected to be compensated within a reasonable range of the competitive median in 2010.[77]

The O&C Committee ultimately concluded that "the current balance of base salary, annual cash incentive award and long-term incentives is appropriate to align the interests of the executive officers with shareholders and reward superior performance."[78]

PSEG Compensation in Relation to Other New Jersey Utilities

As previously stated, PSEG relies upon comparisons to a peer group to determine the competitiveness of compensation offered to its executives. These comparisons for the two most recent years for named executive officers are documented in the Human Resources chapter and have been referenced in the preceding discussion.

Two of the sixteen companies selected by PSEG as peers are utility holding companies that operate in New Jersey – Consolidated Edison, Inc. and FirstEnergy Corp. In identifying its peers, PSEG considered such metrics as revenues, net income, and market capitalization .

The following table compares PSEG's compensation of certain senior executives with three publicly-traded, combination electric and gas utilities that operate in New Jersey:[79]

[77] PSEG Proxy Statement filed March 8, 2010 (p. 27).

[78] PSEG Proxy Statement filed March 8, 2010 (p. 24).

[79] Publicly-traded utility holding companies with natural gas operations in New Jersey such as AGL Resources, New Jersey Resources, and South Jersey Industries were considered for inclusion in the peer group but were dismissed because their operating metrics (revenues, net income, and market capitalization) were significantly different than PSEG's.

Table 6-13 – Comparison of Total Exective Compensation

Comparison of Total Executive Compensation			
Description	2007	2008	2009
Principal Executive Officer:			
PSEG	(A)	$6,000,747	$8,715,970
New Jersey Utilities – Mean	9,845,909	10,260,288	10,170,197
New Jersey Utilities – Median	8,434,769	10,013,360	10,170,197
Principal Financial Officer:			
PSEG	2,261,813	2,231,282	(A)
New Jersey Utilities – Mean	2,386,137	1,984,786	2,000,864
New Jersey Utilities – Median	2,386,137	1,605,935	2,000,864
EVP & General Counsel:			
PSEG	2,116,658	1,770.852	(A)
New Jersey Utilities – Mean	2,407,530	2,509,480	2,109,267
New Jersey Utilities - Median	2,407,530	2,509,480	2,109,267
President & COO of Subsidiary:			
PSE&G	1,318,907	1,508,747	3,267,943
Power	3,738,851	2,213,153	2,495,109
New Jersey Utilities – Mean	2,828,384	3,760,382	2,635,754
New Jersey Utilities – Median	2,781,440	3,546,138	2,336,714

Sources: Derived from proxy statements filed in 2008, 2009, and 2010. Subsequent modifications of prior year data were ignored for purposes of this table.

New Jersey utilities = Consolidated Edison, FirstEnergy, and Pepco Holdings.

Note: Non-recurring or abnormal compensation was excluded if disclosed (e.g., discretionary bonuses, relocation expenses, etc.). If two or more people held the same position during a given year, amounts were excluded from the table since differences in tenure and experience would make the data less meaningful. For comparison purposes, titles used by other companies may have been slightly different

(A) More than one person held the position during the year. Because of differences in employee tenure and experience, we have excluded associated compensation data from this table.

Everything else being equal, the complexities involved in managing a larger company and the additional layers of management that generally go along with a larger organization result in higher executive compensation at the most senior levels. As a result, the statistics derived for New Jersey utilities in the preceding table likely have a downward bias because Pepco Holdings is a smaller company than PSEG, Consolidated Edison, or FirstEnergy. However, this may not be immediately evident due to the high degree of variability in executive compensation because of the emphasis placed on pay-for-performance.

In addition, because of changes in executive ranks and differences in the organizational or compensation structure at other utilities, comparative data may be extremely limited. For instance, in some cases, there may be only one or two amounts included in the mean or median results disclosed for other New

Jersey utilities rather than three as the peer group would imply. For these reasons and others, it would be inappropriate to draw any definitive conclusions from the limited, publicly-available data presented in the preceding table with respect to the level of compensation paid to PSEG senior executives. However, we note that the company and the O&C Committee have retained experts to monitor this and other data on a periodic basis, and they generally believe that executive compensation is reasonable.[80]

Ethics and Compliance

PSEG uses a governing document entitled "Business Conduct Compliance Program" (BCCP) to provide guidance in carrying out an effective ethics and compliance program, while ensuring that all PSEG employees conduct themselves in accordance with high ethical standards and comply with the company rules as set forth in PSEG's Standards of Integrity. The Executive Officer Group (EOG) has overall responsibility for the BCCP and its implementation; however PSEG has created a Compliance Council that has more specific oversight responsibility for the BCCP.[81] The Council is made up of the following members:[82]

- Executive Vice President and General Counsel (Chair and Chief Compliance Officer) – J.A. Lon Bouknight, Jr.
- President and Chief Operating Officer – PSE&G - Ralph LaRossa
- President and Chief Operating Officer – PSEG Power - William Levis
- Chief Financial Officer - Caroline Dorsa
- Executive Vice President – Strategy and Development - Randall Mehrberg
- Vice President – Internal Auditing Services - William Metzger
- Senior Vice President – Human Resources - Margaret Pego
- Vice President – Regulatory - Tamara Linde

Hugh Mahoney serves as the General Compliance Counsel to the Council. In this position, he provides a report to the Council three times a year during the Council's meetings.[83] He also provides quarterly and annual reports to the Audit Committee.[84]

The role of the General Compliance Counsel in PSEG has changed over the past few years. An assessment of the Compliance function was completed by Peter Veniero of Sills, Cummis, and Gross in 2007. One of the recommendations from the assessment was that the person that has day-to-day guidance of the Compliance function should be more visible in the leadership of the company, the organization chart and among employees. This led to Mr. Mahoney beginning to make presentations to the Audit Committee in 2008. As of July 2009, Mr. Mahoney began reporting directly to the EVP – General Counsel, R. Edwin Selover. He had previously reported to the VP and SVP of the Law function.[85]

[80] The one exception being Ralph Izzo's compensation which is acknowledged to be below that of the company's peers but has remained so for the reasons previously stated in this chapter.
[81] Response to Discovery, OC-65.
[82] Interview with Hugh Mahoney, General Compliance Counsel, August 3, 2010.
[83] Response to Discovery, OC-65.
[84] Interview with Hugh Mahoney, General Compliance Counsel, August 3, 2010.
[85] Ibid.

R. Edwin Selover, who served as the Ethics Counsel, retired in January 2010, and the Ethics and Compliance functions were merged together into the Office of Ethics and Compliance.[86] Mr. Mahoney currently serves as the PSEG Ethics and Compliance Counsel.[87]

PSEG has its employees (union and non-union) complete an annual integrity training program. The training summarizes the Company's expectation for behavior and reiterates the importance of the employee's compliance with the Standards of Integrity and law in the course of carrying out their duties of employment. These Standards establish common expectations for behavior for all employees regarding the conduct of PSEG's businesses and operations. They apply to all employees (union and non-union), directors, and suppliers. The Standards also set expectations regarding employee interactions with other employees as well as third parties and the management and use of PSEG's assets.[88] Overland notes that the Standards are updated on a consistent basis to ensure compliance with applicable laws and regulations.[89] The 2009 training module was delivered to PSEG employees in the August/September timeframe. The goal for PSEG is to have all employees in the company (union and non-union) to complete the training.

PSEG also uses an Ethics Culture Survey to gauge the company's efforts to provide a work environment that achieves the highest level of integrity and ethical values. The survey is available to all employees and originates from the Compliance and Ethics Leadership Council ("CELC"), which is a division of the Corporate Executive Board. Although participation in the survey was voluntary, over 89% of PSEG employees completed the survey in 2009, which was the highest for any company that participated in the CELC survey.[90] Typically, the survey includes approximately 20 questions from the CELC database and an additional five to seven questions from prior surveys to benchmark against prior PSEG data.[91]

In 2009, PSEG wanted to focus specifically on improving its scores relating to four questions regarding ethical behavior. The topics of the four questions are listed below.

- PSEG takes appropriate action when unethical behavior is identified
- Senior management of my company demonstrates a commitment to ethical behavior
- Employees will circumvent the rules even if they think they won't get caught
- Employees' requests for confidentiality when reporting an ethical concern will be respected

PSEG's goal was to improve the percentage of favorable responses on these questions from 57% in 2008 to 68% in 2009. PSEG was able to achieve a 67% favorable response rate in 2009, falling just short of their expectation. Overland noted that the union employees favorable responses were significantly lower than the non-union responses for these four questions.[92]

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[86] Response to Discovery, OC-365.
[87] Response to Discovery, OC-812.
[88] Response to Discovery OC-65.
[89] Response to Discovery, OC-77.
[90] Response to Discovery, OC-382.
[91] Interview with Hugh Mahoney, August 3, 2010.
[92] Response to Discovery, OC-382.

Overall, PSEG's 2009 survey results for non-union employees exceeded CELC benchmarks and union survey results were close to the CELC benchmarks in the areas of: clarity of expectations, awareness, and manager preparedness. However, the questions within the Tone at the Top component showed that PSEG was significantly below the CELC benchmark and the company average for both non-union and union employees, respectively.[93] Part of the action plan to increase the scores in the Tone at the Top component is to create focus groups and Compliments and Concerns (2C) meetings. These meetings and focus groups are designed to provide a platform for management to listen to employees' concerns regarding the ethics leadership at PSEG.[94]

The Compliance function is responsible for two metrics in the balanced scorecard for the Law Department. The two metrics are: Enhancement of Corporate Culture for Ethics and Compliance and Compliance Matters Cycle Time. The Enhancement of Corporate Culture for Ethics and Compliance metric is measured using the Integrity Index from the CELC survey.[95] PSEG achieved the CELC benchmark (surveyed company average) for the survey, but did not achieve the top quartile benchmark. For the balance scorecard purposes, the metric was deemed achieved, but in the interview with Mr. Mahoney, the goal for 2010 is to achieve the 2009 top quartile benchmark in the CELC survey for non-union employees and a 10% increase from 2009 in the index score for the union.[96]

The Compliance Matters Cycle Time metric is measured by determining what percentage of matters opened in the compliance data system are closed within 75 days. The Compliance function achieved the metric in 2009. The goal was 80% and the actual percentage at year end was 92.[97] It was noted by Overland that PSEG's goal was to close the cases in the compliance data system in 75 days while PSEG noted that the benchmark data showed the median number of days to open and close a case is 45 days.[98] In an interview with Mr. Mahoney, it was explained that PSEG plans to increase their expectation and balanced scorecard metric in phases to 100% completion within 45 days as more resources and training are made available to the Compliance function.[99]

In his interview, Mr. Mahoney mentioned several measures that he is evaluated on during his performance appraisals. He noted that he is responsible for the balanced scorecard metrics listed above. He is also being measured on developing a successor. Mr. Mahoney has an attorney working with him, Frank Romano, that is dedicated to learning Mr. Mahoney's roles and responsibilities to become his successor. This arrangement has been in place since April 2010. Mr. Mahoney also has an information technology employee working with him on a consistent basis to learn the role information

[93] Ibid.
[94] Interview with Hugh Mahoney, August 3, 2010.
[95] Response to Discovery, OC-422.
[96] Interview with Hugh Mahoney, August 3, 2010.
[97] Response to Discovery, OC-422.
[98] Response to Discovery, OC-880.
[99] Interview with Hugh Mahoney, August 3, 2010.

technology has in the Compliance function. He is also being measured on the ability to standardize all of the formatting and content of the investigation reports.[100]

The key information system that the Ethics and Compliance function uses is a case tracking tool called IRIMS (Incident Reporting and Investigation Management Software). It tracks all ethics and compliance matters from initiation to completion. It tracks the cycle time and houses the final report on the issue. It is also the system that is used to send out the 30 day notice letter to follow up on any recommendations that were made by the Compliance Council. The system was recently updated with a new component package called Perspective that went live after the July 2009 Audit Committee meeting.[101] The Perspective upgrade served to replace an unsupported case management application and database. The upgrade improves the flexibility, querying, and reporting capabilities of IRIMS. It also incorporates a simplified interface and allows for interactive management, analysis, and reporting of compliance and ethics matters.[102]

The Ethics and Compliance function at PSEG has an Integrity Line where employees can disclose any observances or complaints regarding accounting, auditing, and internal control matters; any misappropriation of company assets or proprietary information; and any violation of company or government laws and regulations. These disclosures can also be made to the General Compliance Counsel on a confidential and/or anonymous basis.[103] In his interview, Mr. Mahoney stated that PSEG initiates approximately 200 compliance cases per year that come through the aforementioned channels of communication. However, most of these are employee inquiries and do not require further investigation.[104]

PSEG uses a third party called Global Compliance Services (GCS) to staff the Integrity lines. Employees can call a 1-800 number to reach GCS and create a report that GCS processes and sends to PSEG. An employee in Internal Audit receives an email with a report of the calls into the Integrity Line and the matter to be addressed. The Internal Audit employee then sends this report to Mr. Mahoney who decides the appropriate course of action. Mr. Mahoney normally makes one of the following determinations on the matters received from the Integrity Line.

- Matters involving non-operating employees are sent to Internal Audit for further investigation
- Petty theft matters are remanded to the Business Assurance and Resiliency function for further investigation
- Any OSHA related items are sent to the Environmental Health & Safety group for further investigation
- Any human resources related matters are remanded to the Human Resources division

[100] Ibid
[101] Ibid.
[102] Response to Discovery, OC-362.
[103] Response to Discovery, OC-26.
[104] Interview with Hugh Mahoney, August 3, 2010.

On rare occasions, outside counsel will be used when PSEG does not possess the expertise to conduct a proper investigation (i.e. sexual harassment matters).

Sarbanes-Oxley (SOX) Compliance

Enacted in 2002, the Sarbanes-Oxley Act (SOX) was a response to corporate malfeasance by several high profile companies in the late 1990s and early 2000s in which investors lost billions of dollars. While the thrust of previous federal securities regulations concerned disclosure of information to investors by public companies and the fair treatment of investors by the securities industry, SOX was directed at government oversight over public company boards of directors, corporate management, and public accounting firms.

Because many of the SOX requirements do not directly affect PSE&G or its publicly-traded parent, they will not be addressed in this report. Instead, the focus of our review will be on the key SOX requirements with which public company management and boards of directors must comply. In addition, other relevant New York Stock Exchange (NYSE) rules or SEC requirements are also addressed.

Company Commitment to SOX Compliance – PSEG and its subsidiaries have directed a significant amount of attention to SOX compliance in recent years. Evidence of this is as follows:

- Existence of a dedicated Internal Controls group that is responsible for overseeing compliance with SOX, especially Section 404 which concerns management's assessment of internal controls. This group used to report to the Vice President of Enterprise Risk Management & Chief Risk Officer until June 30, 2009. It now reports to the Vice President of Internal Auditing Services (4 persons).[105]
- **[Begin Confidential]** **[End Confidential]**[106]
- **[Begin Confidential]** **[End Confidential]**[107]
- **[Begin Confidential]** **[End Confidential]**[108]

[105] Response to Discovery, OC-389.
[106] Response to Discovery, OC-45 Update 2, pp. 44 and 67 (Restricted On-Site Only).
[107] Response to Discovery, OC-574, p. 1 of July 15, 2008 Update (Restricted On-Site Only).
[108] Response to Discovery, OC-574 (p. 2 of December 16, 2008 Update, p. 3 of February 17, 2009 Update, and p. 4 of February 16, 2010 Update). (Restricted On-Site Only) Even though 2009 results did not include the results of one last

- Presentation of SOX compliance updates to the Audit Committee on a routine basis.[109]

Selected SOX Requirements – In terms of evaluating the steps taken by PSE&G and PSEG management to comply with SOX, we believe the following SOX requirements are most pertinent:

Certification of 10-Q and 10-K reports by the "principal executive officer" and "principal financial officer" (Section 302)

According to SOX, each quarterly and annual financial report filed with the SEC (Forms 10-Q and 10-K) must include a certification by the principal executive and financial officers.

Every 10-Q and 10-K associated with the operations of PSEG and PSE&G in 2008 and 2009 have a certification signed by the applicable CEO and CFO. To paraphrase, both of the officers for each company certify that all material facts have been disclosed, that the financial statements are fairly presented in all material respects, that they are responsible for establishing and maintaining internal controls related to financial reporting and related disclosures, that they have evaluated the effectiveness of these internal controls, that they have disclosed any changes to these internal controls, and that they have kept the external auditors and Audit Committee of the Board of Directors apprised of any significant problems with internal controls over financial reporting. Other than an acknowledgement that the replacement of the customer information system materially affected the internal controls over financial reporting for several quarters in 2009, we noted no reported exceptions to these certifications in our review.[110]

The CEO and CFO certifications are supported by work performed by an internal Disclosure Committee. This committee consists of various members of management, primarily representing the accounting, finance, regulatory, and legal functions. The Disclosure Committee monitors, evaluates, and documents the effectiveness of disclosure controls and procedures. In carrying out these duties, the committee will obtain sub-certifications from management that address pertinent controls and associated disclosures.[111]

Management assessment of internal controls (Section 404)

SOX calls for management to state its responsibility for and assessment of the Company's internal controls over financial reporting. In addition, the external auditors generally must attest to this assessment as part of its audit of the Company's financial information.

As part of its annual Form 10-K filing, PSEG and PSE&G management concluded that internal control over financial reporting was effective for both companies as of December 31, 2008 and December 31,

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remaining key control which was to be completed prior the filing of the 2009 Form 10-K, the trend in control deficiencies from year to year would not be impacted.

[109] Response to Discovery, OC-574.

[110] Review of Form 10-Qs and 10-Ks associated with 2008 and 2009 company operations.

[111] Response to Discovery, OC-1026.

2009. In addition, neither company identified material weaknesses in internal control over financial reporting for these two dates.

Deloitte & Touche LLP issued unqualified opinions on PSEG's internal control assessment as December 31, 2008 and December 31, 2009. However, management's report for PSE&G was not subject to attestation by the independent registered public accounting firm pursuant to temporary rules of the SEC.[112]

A more detailed discussion of the internal control testing failures and outstanding deficiencies in internal controls identified by the Company and the external auditors can be found in our discussion of the Accounting function in Chapter 12. The significance of these deficiencies did not rise to a level that required disclosure by either the company or the external auditor in the publicly-disclosed financial reports.

Auditor independence (Title II)

To mitigate some of the actual or perceived conflicts of interests that external auditors face when providing services to audit clients, SOX put in place certain restrictions on the interactions between company management and external auditors. They include the following:

- Reporting of the external auditor to the Audit Committee of the Board of Directors (Section 204)

  SOX requires a direct line of communication by the external auditors to the Audit Committee of the Board of Directors on certain matters.

  The PSEG Audit Committee Charter gives the Audit Committee the authority to appoint, terminate, compensate, and oversee the work of the independent auditor. Specifically, the independent auditor reports directly to the Audit Committee. [113]

  Our review of the Audit Committee meeting minutes in 2008 and the majority of 2009 indicated that Deloitte & Touche representatives attended and/or participated in every Audit Committee meeting and teleconference call. In many cases, the Audit Committee met with Deloitte & Touche representatives in executive session without PSEG management present.[114]

- The prohibition of certain services performed by the external auditor (Section 201)

  SOX prohibits Deloitte & Touche, PSEG's and PSE&G's external auditor, from performing a wide range of ancillary non-audit services including, but not limited to, bookkeeping, financial

[112] PSEG December 31, 2008 Form 10-K (pp. 179-183) and PSEG December 31, 2009 Form 10-K (pp. 182-186).
[113] PSEG Audit Committee Charter amended and restated December 15, 2009.
[114] Review of PSEG Audit Committee minutes from January February 19, 2008 to October 27, 2009.

information systems design and implementation, appraisal or valuation services, internal audit outsourcing, and human resources.

The company reported that Deloitte & Touche had performed a handful of non-audit services during 2008 and 2009, all involving matters associated with income taxes. These services totaled $1,099,000 and $33,000 in 2008 and 2009, respectively.[115] The Audit Committee considered these services and the level of fees paid to Deloitte & Touche to perform them and concluded that the firm had the requisite independence.[116] We note that tax-related services are not specifically prohibited by SOX.

- Pre-approval of services provided by the external auditor by the Audit Committee (Section 202)

SOX requires that all audit and non-audit services provided by the external auditor must be pre-approved by the audit committee of the Company. However, it does make an exception for de minimis non-audit services under certain circumstances. In those limited cases, an audit committee can delegate its pre-approval authority to one or more members.

The PSEG Audit Committee Charter states that either the Audit Committee or the Chair of the Audit Committee shall pre-approve the fees to be paid to the independent auditor for all services. There is no mention in the charter of any cap on amounts that the Chair can approve on his/her own.[117] When asked if there was a dollar limit that the Audit Committee Chair could not exceed when pre-approving services, the company provided a February 2010 Audit Committee resolution **[Begin Confidential]**

[End Confidential][118] In our review of minutes of the PSEG Audit Committee meetings held in 2008 and the majority of 2009, we observed no instances in which the Audit Committee Chair pre-approved services from the external auditor on his own.

However, as the charter is currently written, the Chair of the Audit Committee has no restrictions on the amount of fees he can commit the Company to pay for eligible products or services purchased from the external auditors between regularly scheduled Audit Committee meetings. While there is no evidence in our review of the Audit Committee minutes that this authority was abused in any way, it makes good business sense to set an upper limit or cap on the amount of products or services that one person can approve. This not only protects the Company's financial interests but also the director from potential second-guessing.

[115] Response to Discovery, OC-80.
[116] PSEG Proxy Statements filed March 16, 2009 (p. 43) and filed March 8, 2010 (p. 53).
[117] PSEG Audit Committee Charter amended and restated December 15, 2009.
[118] Response to Discovery, OC-1373 (Restricted On-Site Only).

We recommend the Company consider setting a dollar cap on the delegation authority provided to the Chair of the Audit Committee for eligible products and services offered by the external auditor between regularly scheduled Audit Committee meetings.[119]

- Mandatory audit partner rotation (Section 203)[120]

  SOX requires that the lead audit partner of the external auditor rotate off the engagement every five years.

  The Deloitte & Touche Lead Client Service Partner rotated off the PSEG and PSE&G audits in February 2008 in accordance with the external auditor's Rotation Policy for Audit Partners and as required by SOX.[121]

  The company asserts that the external auditor has complied with this requirement since SOX was enacted.[122]

- Disclosures by the external auditor

  In addition to the SOX requirements concerning external auditor independence that were incorporated in the SOX Compliance discussion, SOX also authorizes the Public Company Accounting Oversight Board (PCAOB) to establish independence standards and rules as it sees fit (Section 103). Rule 3600T of the PCAOB adopts the Independence Standards Board Standard No. 1 on an interim basis.[123] This standard requires that at least on an annual basis the auditor shall:

  > a. Disclose to the audit committee of the company . . ., in writing, all relationships between the auditor and its related entities and the company and its related entities that in the auditor's professional judgment may reasonably be thought to bear on independence;
  >
  > b. Confirm in the letter that, in its professional judgment, it is independent of the Company within the meaning of the [Securities] Acts;

[119] The dollar cap could be expressed as either a specific dollar amount or a percentage of the total fees paid to the external auditor. Products and services exceeding the cap would need to be approved by the entire Audit Committee at a regular or special meeting.

[120] On a related note, SOX called for a study to be performed by the United States General Accounting Office (GAO) on the subject of mandatory audit firm rotation (Section 207) as a possible method to improve external auditor independence. In November 2003, the GAO released the results of its study, which concluded that the SEC and the PCAOB monitor the effectiveness of the other SOX requirements first before mandating that audit firms be rotated. Further discussion of audit firm rotation will take place in our discussion of the Accounting function.

[121] Audit Committee meeting minutes dated February 19, 2008.

[122] Response to Discovery, OC-572.

[123] The Independence Standards Board was created by the SEC and the American Institute of Certified Public Accountants (AICPA) to develop and maintain independence standards for auditors of SEC registrants.

c. And discuss the auditor's independence with the audit committee.

The PSEG Audit Committee Charter states that the committee will ensure that the independent auditor submits, at least annually, a formal written statement specifying all relationships between the auditor and the company and certifying the auditor's independence.[124]
A review of the Audit Committee meeting minutes for the period from early 2008 to late 2009 shows that Deloitte & Touche discussed their independence with the committee during a October 30, 2008 conference call and at the September 15, 2009 regularly scheduled committee meeting. In both cases, Deloitte & Touche concluded that the firm was independent within the meaning set forth by the SEC and the PCAOB.

Notwithstanding this conclusion, Deloitte & Touche **[Begin Confidential]**

[End Confidential][125]

<u>"Whistleblower" communications (Section 301)</u>

SOX requires the audit committee to establish procedures concerning the reporting of complaints to the Company related to accounting, internal accounting controls, and auditing matters. With respect to employees, they are to be provided an avenue to report their concerns confidentially and anonymously.

Included in the PSEG Audit Committee Charter are the committee's following responsibilities:[126]

[124] PSEG Audit Committee Charter amended and restated December 15, 2009.
[125] Response to Discovery, OC-51 (Original and Update). Note that the company did not classify either response as restricted. However, in its response to OC-591, the company indicated that the original response to OC-51 had inadvertently been provided off-site. As a result, we have been conservative in treating the original and updated responses to OC-51 as restricted.
[126] PSEG Audit Committee Charter amended and restated December 15, 2009.

Assure that the Corporation has adequate, independent procedures for:

- the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls, or auditing matters;
- the confidential, anonymous submission by employees of concerns regarding questionable accounting or auditing matters; and
- the reporting of allegations of material violations of securities laws and fiduciary requirements by attorneys representing the Corporation and its majority owned subsidiaries in practice before the Securities and Exchange Commission.

PSEG's Standards of Integrity provide employees with a number of different conduits for reporting concerns and possible misconduct. They can contact the Ethics Counselor, the Compliance Counsel, a designated Assistant General Counsel, or a third-party-staffed Integrity Line. These communications can be made either confidentially or anonymously.[127] Once reported, the matters are reviewed to determine what further action should be taken. Further discussion of PSEG's compliance program can be found elsewhere in this chapter.

Code of ethics (Section 406)

SOX requires that a company disclose its code of ethics for senior financial officers. If the code is changed or waived, immediate disclosure must be made.

PSEG's code of ethics is formalized in a document referred to as its Standards of Integrity. This document is readily accessible on the company's website. Every year, all PSEG directors and non-represented employees must complete a certification of compliance questionnaire acknowledging their continued understanding of the Standards of Integrity.

Waivers to any provision of the Standards of Integrity can only be granted by executive management or, in the case of waivers requested by executive management, by the PSEG Board of Directors. No waivers to any provision of the Standards of Integrity have been made to any officer or director from 2007 to 2009.[128]

Audit committee financial expert (Section 407)

SOX requires a company to disclose that it has at least one financial expert on its audit committee, and if not, an explanation for such omission. While the act provides examples of acumen that a "financial expert" must have (e.g., experience with GAAP financial statements (both preparation and auditing), experience with the use of estimates in setting accruals and/or reserves, experience with internal

[127] Response to Discovery, OC-26 and the PSEG Standards of Integrity dated 2010.

[128] Response to Discovery, OC-77 and the PSEG Standards of Integrity dated 2010. According to Hugh Mahoney, General Compliance Counsel, only one waiver to the Standards of Integrity has recently been granted, and that occurred in 2007 and involved 1 share of stock, presumably by a non-officer (Source: Interview with Hugh Mahoney on August 3, 2010).

accounting controls, and experience with the responsibilities of audit committees), the manner in which this expertise is acquired can occur in one of three different ways:

- education and experience as a principal financial officer, principal accounting officer, controller, public accountant or auditor or experience in one or more positions that involve the performance of similar functions;

- experience actively supervising a principal financial officer, principal accounting officer, controller, public accountant, auditor or person performing similar functions, or experience overseeing or assessing the performance of companies or public accountants with respect to the preparation, auditing or evaluation of financial statements; or

- other relevant experience.

According to publicly-filed proxy information, PSEG's Audit Committee members are all "financial experts" except for Hak Cheol Shin.[129] These five "financial experts" all obtained their expertise by virtue of the second attribute listed above -- the active supervision of an accountant.[130] As noted previously, we have recommended that the Board of Directors consider the addition of a current or recently practicing accountant (a CPA with recent Big 4 experience and/or experience as a principal accounting officer) in the future given the complexities of and focus paid to financial reporting matters.

Compliance with Other Relevant NYSE Rules and SEC Requirements

In addition to the requirements listed above that arose from the passage of SOX, PSEG must follow other rules that concern their corporate governance. These include, but are not limited to:

Board member independence

NYSE rules mandate that a majority of directors and all audit committee, corporate governance/nominating committee, and compensation committee members must be independent (Sections 303A.01, 303A.04, 303A.05, and 303A.07). To arrive at the conclusion that a director is independent, the NYSE provides examples of conflicts of interests that would disqualify him or her. These include ties to the Company through recent employment, non-board compensation, external auditor affiliation, or significant business dealings.[131]

In proxy statements filed in early 2009 and 2010, the Board of Directors concluded that all of its members except for Ralph Izzo were independent pursuant to the company's Corporate Governance Principles and the requirements set forth by the NYSE.[132] Since Mr. Izzo was not a member of the PSEG

[129] PSEG Proxy Statement filed March 8, 2010 (p. 8).
[130] Response to Discovery, OC-1371.
[131] Response to Discovery, OC-282 (restricted).
[132] PSEG Proxy Statement filed March 16, 2009 (p. 3) and PSEG Proxy Statement filed March 8, 2010 (p. 3).

Audit Committee, Corporate Governance Committee, or Organization & Compensation Committee, PSEG complied with the NYSE rules concerning committee composition.

[Begin Confidential]

[End Confidential][133] **[Begin Confidential]**

[End Confidential][134] **[Begin Confidential]**

[End Confidential][135]

Internal audit function

NYSE rules require a listed company to have an internal audit function (Section 303A.07).

In September 2010, PSEG had an Internal Audit Department numbering 25 employees (excluding the Internal Controls group) reporting to Caroline Dorsa, Executive Vice President and CFO.[136] Previously, the Internal Audit Department reported to the Executive Vice President – General Counsel.[137] A further discussion of the Internal Audit Department is documented in our review of the accounting function and internal controls in Chapter 12.

133 In 2009, the Organization & Compensation Committee's outside advisor was asked to comment on RiskMetrics' report concerning PSEG (see response to Discovery, OC-463).
134 Corporate Governance Committee meeting minutes dated April 21, 2009.
135 Interviews with members of the PSEG Board of Directors.
136 Response to Discovery, OC-1270, pp. 91 and 109 of 116.
137 Response to Discovery, OC-375.

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Attachment 6-1

PSEG Board of Directors Biographical Information

Name of Director	Biographical Information	Election Year	Recent Committee Assignments	Recent Committee Chairmanships
Ralph Izzo	Age 51. Director of PSE&G, Power, Energy Holdings and Services. Chair of the Executive Committee. Chairman of the Board, President and Chief Executive Officer of PSEG since April 1, 2007. Was President and Chief Operating Officer of PSEG from October 2006 to April 2007 and President and Chief Operating Officer of PSE&G from October 2003 to October 2006 and was a Vice President in charge of various functions, including Corporate Planning, Appliance Services and Utility Operations from March 1998 to October 2003.	2006	Executive Committee	Executive Committee
Albert R. Gamper, Jr.	Age 67. Director of PSE&G, Chair of Organization and Compensation Committee and member of Audit Committee, Executive Committee and Finance Committee. Until retirement, was Chairman of the Board of CIT Group, Inc., Livingston, New Jersey, a commercial finance company, from July 2004 until December 2004. Was Chairman of the Board and Chief Executive Officer of CIT Group, Inc. from September 2003 to July 2004. Chairman of the Board, President and Chief Executive Officer from June 2002 to September 2003 and was President and Chief Executive Officer 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 CIT Group, Inc., from January 2000 to June 2001 and President and Chief Executive Officer from December 1989 to December 1999. Trustee to the Fidelity Group of Funds.	2000	Audit Committee; Finance Committee; Executive Committee	Organization and Compensation Committee
Conrad K. Harper	Age 64, is retired President and Chief Executive Officer of Baltimore Gas and Electric Company a position he held from 2000 through 2004. From 1982 to 1995, Mr. Heintz was Chairman of the Maryland Public Service Commission. Previously he served as agency head of the Maryland Employment Security Administration and was an elected member of the Maryland legislature.	1997	Finance Committee; Corporate Governance Committee	Corporate Governance Committee
William V. Hickey	Age 64. Chair of Fossil Generation Operations Oversight Committee and Chair of Nuclear Generation Operations Oversight Committee and member of Audit Committee and Organization and Compensation Committee. Has been President and Chief Executive Officer of Sealed Air Corporation, Elmwood Park, New Jersey, which manufactures food and specialty protective packaging materials and systems, since March 2000. Was President and Chief Operating Officer from December 1996 to February 2000, Director of Sealed Air Corporation and Sensient Technologies Corporation.	2001	Fossil Generation Operations Oversight Committee; Nuclear Generation Operations Oversight Committee; Audit Committee; Organization and Compensation Committee	Fossil Generation Operations Oversight Committee; Nuclear Generation Operations Oversight Committee

Attachment 6-1

Name of Director	Biographical Information	Election Year	Recent Committee Assignments	Recent Committee Chairmanships
Shirley Ann Jackson	Age 62. Chair of Finance Committee and member of Audit Committee, Executive Committee, Fossil Generation Operations Oversight Committee, Nuclear Generation Operations Oversight Committee and Organization and Compensation Committee. Has been President of Rensselaer Polytechnic Institute, Troy, New York, since July 1999. Was previously a director of PSEG from 1987 to 1995, prior to becoming Chair, U.S. Nuclear Regulatory Commission, from July 1995 to July 1999. Director of FedEx Corporation, IBM Corporation, Marathon Oil Corporation, Medtronic, Inc. and the NYSE Euronext.	2001	Fossil Generation Operations Oversight Committee; Nuclear Generation Operations Oversight Committee; Audit Committee; Organization and Compensation Committee; Finance Committee; Executive Committee	Finance Committee
David Lilley	Age 62. Member of Audit Committee, Finance Committee, Fossil Generation Operations Oversight Committee and Nuclear Generation Operations Oversight Committee. Until retirement, was Chairman of the Board, President and Chief Executive Officer of Cytec Industries Inc., West Paterson, New Jersey, which is a global specialty chemicals and materials company, from January 1999 until December 2008. Was President and Chief Executive Officer from May 1998 to January 1999 and President and Chief Operating Officer from January 1997 to May 1998. Director of Arch Chemicals Inc., Cytec Industries Inc. and Rockwell Collins, Inc.	2009	Audit Committee; Finance Committee; Fossil Generation Operations Oversight Committee; Nuclear Generation Operations Oversight Committee	None
Thomas A. Renyi	Age 63. Chair of Audit Committee and member of Corporate Governance Committee, Finance Committee and Organization and Compensation Committee. Until retirement, was Executive Chairman of The Bank of New York Mellon Corporation, New York, New York, a provider of banking and other financial services to corporations and individuals, from July 2007 until August 2008. Was Chairman of the Board and Chief Executive Officer of The Bank of New York Company, Inc., and The Bank of New York, from February 1998 to July 2007. Director of RiskMetrics Group, Incorporated.	2003	Audit Committee; Corporate Governance Committee; Finance Committee; Organization and Compensation Committee	Audit Committee
Hak Cheol (H.C.) Shin	Age 51. Member of Audit Committee, Corporate Governance Committee, Fossil Generation Operations Oversight Committee and Nuclear Generation Operations Oversight Committee. Has been Executive Vice President - Industrial and Transportation Business of 3M Company, St. Paul, Minnesota, a diversified technology company, with product lines in the consumer and office, health care, electronics, industrial, graphics, transportation, safety and telecommunications markets, since January 2006. Was Executive Vice President - Industrial Business from June 2005 to January 2006. Was Division Vice President - Industrial Adhesives and Tapes Division from July 2003 to June 2005. Division Vice President - Electronics Markets Materials Division from October 2002 to June 2003, and Division Vice President - Superabrasives and Microfinishing Systems Division from March 2001 to October 2002.	2008	Audit Committee; Corporate Governance Committee; Fossil Generation Operations Oversight Committee and Nuclear Generation Operations Oversight Committee	None

Attachment 6-1

Name of Director	Biographical Information	Election Year	Recent Committee Assignments	Recent Committee Chairmanships
Richard J. Swift	Age 64. Has been Presiding Director since June 2007. Director of PSE&G, Member of Corporate Governance Committee, Executive Committee, Fossil Generation Operations Oversight Committee, Nuclear Generation Operations Oversight Committee and Organization and Compensation Committee. Was Chairman of the Financial Accounting Standards Advisory Council from January 2002 to December 2006. Was Chairman of the Board, President and Chief Executive Officer of Foster Wheeler Ltd., Clinton, New Jersey, which provides design, engineering, construction, manufacturing, management, plant operations and environmental services, from April 1994 until October 2001. Director of CVS Caremark Corporation, Hubbell Incorporated, Ingersoll Rand Limited and Kaman Corporation.	1994	Corporate Governance Committee; Executive Committee; Fossil Generation Operations Oversight Committee; Nuclear Generation Operations Oversight Committee; Organization and Compensation Committee	Presiding Director
Sources: 2008 and 2009 PSEG Proxy Statements Schedule 14a filed with the SEC; 'Committee Information' on PepcoHoldings.com				

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PSEG and Subsidiary Officers Biographical Information

Name of Officer	Title	Organization	Experience	Education
Ralph Izzo	Chairman of the Board, President, CEO	PSEG Inc.	Ralph Izzo has been chairman, president and chief executive officer of Public Service Enterprise Group Incorporated (PSEG) since April, 2007. He had served as president and chief operating officer of PSEG since October, 2006 when he was also elected to the Board of Directors. Earlier, Mr. Izzo was president and chief operating officer of Public Service Electric and Gas Company. Since joining PSE&G in 1992, Mr. Izzo was elected to several executive positions within PSEG's family of companies, including PSE&G senior vice president – utility operations, PSE&G vice president – appliance service, PSEG vice president - corporate planning, Energis Incorporated senior vice president – finance and information services, and PSE&G vice president - electric ventures. In these capacities, he broadened his experience in the areas of general management, strategic planning and finance. Mr. Izzo is a well-known leader within the utility industry, as well as the public policy arena. His public policy experience includes service as an American Physical Society Congressional Science Fellow, in the office of U.S. Senator Bill Bradley. He also served four years as a senior policy advisor in the Office of New Jersey Governor Thomas H. Kean, specializing in energy, science and technology. Mr. Izzo is chairman of the board for the Center for Energy Workforce Development (CEWD), as well as for the Drumthwacket Foundation. He serves on the board of directors for the New Jersey Chamber of Commerce, the New Jersey Utilities Association, the Edison Electric Institute (EEI), and the Nuclear Energy Institute (NEI). Mr. Izzo is also a member of the Council on Competitiveness – Energy Security; Innovation and Sustainability Initiative Steering Committee, and on the board of trustees for the New Jersey Network Foundation.	Mr. Izzo's career began as a research scientist at the Princeton Plasma Physics Laboratory, performing numerical simulations of fusion energy experiments. He has published or presented over 35 papers on magnetohydrodynamic modeling. Mr. Izzo received his Bachelor of Science and Master of Science degrees in mechanical engineering and his Doctor of Philosophy degree in applied physics from Columbia University. He also completed the requirements for a Master of Business Administration degree, with a concentration in finance from the Rutgers Graduate School of Management. He is listed in numerous editions of Who's Who and has been the recipient of national fellowships and awards.
Caroline Dorsa	Executive Vice President and CFO	PSEG Inc., PSE&G, PSEG Services Corporation	Caroline Dorsa was named executive vice president and chief financial officer for Public Service Enterprise Group Incorporated (PSEG) in April 2009. She is also executive vice president and chief financial officer of Public Service Electric and Gas Company (PSE&G), and PSEG Services Corporation. Ms. Dorsa is responsible for all financial functions, including Internal Audit Services. She also shares leadership of the Corporate Planning team with Randy Mehrberg. She is a member of PSEG's corporate executive leadership team. Ms. Dorsa had been a Director of Public Service Enterprise Group Inc. (PSEG) since 2003, and a member of PSEG's Audit, Corporate Governance and Finance Committees. Ms. Dorsa joined PSEG from Merck & Co., Inc. where she most recently served as senior vice president – global human health, strategy and integration. Immediately prior to her most recent role at Merck, Ms. Dorsa held positions as senior vice president and chief financial officer at both Avaya, Inc., and Gilead Sciences, Inc. Earlier in her career, she held a range of financial positions at Merck, including serving as vice president and treasurer of the company for over 12 years. She was also the Secretary of the Finance Committee of Merck's Board of Directors.	Ms. Dorsa holds a B.A. from Colgate University and an M.B.A from Columbia Business School.
Clarence (Joe) Hopf Jr.	President	PSEG Energy Resources & Trade	Clarence (Joe) Hopf Jr. was named president of PSEG Energy Resources & Trade in June 2008. His responsibilities include management of PSEG Power's generation portfolio and basic gas supply service, purchasing of fuel, mid- and back-office operations as well as trading and marketing activities. Prior to joining PSEG, Mr. Hopf was president of PPL EnergyPlus in Allentown, PA, since 2006. He was responsible for managing PPL's wholesale/retail marketing and trading operation in the United States. Mr. Hopf has held a variety of posts with increasing responsibility in the electric generation and energy trading business since 1981. Prior to joining PPL in 2005 as a senior vice president, he served as a vice president at Goldman Sachs in New York and, before that, at AmerenEnergy in St. Louis.	Note 1

Name of Officer	Title	Organization	Experience	Education
Thomas P. Joyce	President and Chief Nuclear Officer	PSEG Nuclear	Thomas P. Joyce was named president and chief nuclear officer of PSEG Nuclear (Nuclear), in October 2008. He had been senior vice president – operations of Salem/Hope Creek for Nuclear, since June 2007. Mr. Joyce was also vice president – Salem, since January 2007, and previously assumed the role of PSEG Nuclear's site vice president as part of the Nuclear Operating Services Agreement between PSEG and Exelon Corporation. Mr. Joyce has more than 32 years of experience in commercial nuclear power operations, and led Salem through two successful reactor vessel head replacement outages. Salem Unit 1 completed its outage for the lowest station dose, while capturing the world record for shortest head replacement outage. Prior to coming to PSEG Mr. Joyce was site vice president at Exelon Nuclear's Braidwood Station. During his tenure the station achieved overall performance improvements and retained their excellent INPO rating. The plant completed a refueling in 15 days, 14 hours – setting a record for outage efficiency among U.S. pressurized water reactors. Before serving at Braidwood he held leadership positions at Exelon's Byron, Dresden, and Zion Stations, and in the corporate offices of both Exelon Corporation and Exelon Nuclear.	Mr. Joyce holds a Bachelor of Science degree in nuclear engineering from the University of Missouri at Rolla, and a Master of Business Administration degree from the Keller Graduate School of Management. While at Byron, he earned his senior reactor operation (SRO) license.
Ralph A. LaRossa	President and Chief Operating Officer	PSE&G	Ralph A. LaRossa was named president and chief operating officer of Public Service Electric and Gas Company (PSE&G), in October 2006. Prior to this position he was vice president - electric delivery for PSE&G. Mr. LaRossa joined PSE&G in 1985 as an associate engineer and advanced through a variety of management positions in the utility's gas and electric operations. Past positions include vice president - delivery operations support, division manager - Metropolitan electric division, director - distribution operations, manager - gas distribution, project manager for AWMS (automated work management system), assistant division manager, district manager and field engineer in gas distribution. PSE&G is New Jersey's largest electric and gas utility. In 1998 he received Gas Industry Magazine's Outstanding Manager of the Year Award. He is a member of the PJM Designated Officers Committee. He serves on the board of directors for the American Gas Association (AGA), New Jersey Utilities Association (NJUA), New Jersey Performing Arts Center (NJPAC), Partnership for a Drug-Free NJ, and Bergen County's United Way. He also serves as a board of trustee's member of Montclair State University, Newark Alliance, New Jersey Institute for Social Justice, and the Liberty Science Center.	Mr. LaRossa is a graduate of Stevens Institute of Technology with a Bachelor of Engineering degree in industrial engineering, and has completed the Harvard Business School's Program for Management Development.

Name of Officer	Title	Organization	Experience	Education
William Levis	President and Chief Operating Officer	PSEG Power	William Levis was elected president and chief operating officer of PSEG Power (Power), effective June 2007. He also held the title of president and chief nuclear officer of PSEG Nuclear from June 2007 until October 2008. PSEG Power is a major unregulated independent power producer in the U.S. with three main subsidiaries: PSEG Fossil, PSEG Nuclear, and PSEG Energy Resources and Trade. Mr. Levis was previously senior vice president and chief nuclear officer, as part of the Nuclear Operating Services Agreement between PSEG and Exelon Corporation. Under his leadership Nuclear's Salem and Hope Creek stations have advanced to the highest performance levels in the stations' history. Improvement in the stations' work environment has resulted in the closing of two long standing NRC cross-cutting issues - problem identification and resolution, and safety conscious work environment. Additionally, in 2006 the stations generated more electricity than ever in their history and achieved site records for longest continuous single unit run and shortest refueling outage. Mr. Levis has more than 30 years of diversified experience in the nuclear power industry. Before coming to PSEG he was Exelon Nuclear's vice president - Mid-Atlantic operations, where he provided executive oversight of day-to-day operations of the Limerick, Peach Bottom, Three Mile Island and Oyster Creek Stations. He joined Exelon as the Byron Station Manager in 1998 and was promoted to site vice president the following year. In 2001 he was named site vice president at Limerick Generating Station. While under Mr. Levis' leadership Byron also made significant overall improvements. The site established new records for total annual megawatt production, and set station duration efficiency records in each of three consecutive refueling outages. Mr. Levis continued his success at Limerick. Following his arrival, Unit 2 completed its sixth refueling outage in 16 days, 8 hours - making it the most efficient outage of any domestic or foreign G.E. boiling water reactor. Prior to joining Exelon Mr. Levis worked at Ontario Hydro's Pickering Plant and held several positions over a five-year period with Carolina Power & Light's Brunswick facility. During this time the station was removed from the NRC Watch List and set new records in the areas of safety, production and cost. Mr. Levis' background also includes experience with NRC, Westec Services, General Electric Nuclear Services and the U.S. Navy.	He has a Bachelor of Science degree in marine engineering from the U.S. Naval Academy and holds an SRO (senior reactor operator) certification. Mr. Levis retired as a commander in the Naval Reserves and attained his professional engineer license in 1985.
Richard P. Lopriore	President	PSEG Fossil	Richard P. Lopriore was elected president of PSEG Fossil, in May 2007. He oversees operations for natural gas, coal, and oil-fired electric generating units that contribute close to 10,000 megawatts of electricity to PSEG Power's generation portfolio. Mr. Lopriore has been a valuable part of the electric generation industry for more than 36 years. Prior to joining PSEG Fossil, he had been senior vice president - mid-Atlantic operations for Exelon Nuclear, responsible for oversight of the Limerick, Peach Bottom, Oyster Creek and Three Mile Island stations. Mr. Lopriore joined Exelon as plant manager of Byron Stations in 1999 and was promoted to site vice president in 2001. While under his leadership Byron achieved back-to-back "excellent" ratings from industry peers and many other awards for operational excellence. At Byron, Mr. Lopriore also functioned as the central authority for making NRC and other regulatory commitments. In 2003 he became corporate vice president - operations support at Exelon's nuclear headquarters, responsible for both the Midwest and mid-Atlantic regions, and then became vice president - operations, Midwest boiling water reactors in 2004 with oversight for the Clinton, Dresden, LaSalle and Quad Cities stations. Prior to Exelon, Mr. Lopriore held senior leadership roles with Ontario Hydro Nuclear in Canada, where he improved operational performance, capacity factors and maintenance outage execution. Mr. Lopriore also held several key management positions at the Brunswick Nuclear Plant in North Carolina, including plant manager. Here he was successful in getting the station removed from the NRC Watch List and set new records in the areas of safety, production and cost. At Vermont Yankee, he served as the maintenance manager for eight years where he achieved an operational SRO certification for Boiling Water Reactors. Mr. Lopriore began his career as an electrician with New England Power Service Company, performing hands-on maintenance work for hydroelectric, fossil and nuclear plants in both Massachusetts and Vermont.	He received his Bachelor of Science degree from Southern Vermont College

Name of Officer	Title	Organization	Experience	Education
Randall E. Mehrberg	Executive Vice President Strategy & Development - PSEG Services Corporation; Chairman of the Board - Energy Storage & Power; President - PSEG Energy Holdings	PSEG Services Corporation, Energy Storage & Power; PSEG Energy Holdings	Randall E. Mehrberg was named President of PSEG Energy Holdings and Chairman of the Board for Energy Storage & Power in May of 2009. PSEG Energy Holdings develops, manages and owns renewable energy solutions including solar, energy storage and off shore wind. Energy Holdings also manages power plants in the United States and a broad array of energy and other investments in the United States and abroad. Mehrberg is also PSEG's executive vice president responsible for corporate strategy, mergers and acquisitions and corporate development, a position he has held since September 2008. Mehrberg also oversees PSEG's Human Resources functions. He is a member of PSEG's corporate executive leadership team and has leadership responsibility for overseeing the corporate balanced scorecard. Mehrberg's responsibilities include PSEG's emergent technology and transfer group, ensuring development of a corporate strategy that includes a comprehensive assessment of the role of technology in the future of our industry. Mehrberg joined PSEG after serving for eight years in various executive leadership positions at Chicago-based Exelon Corp., the nation's largest electric utility. He was executive vice president, chief administrative officer and chief legal officer from 2006 to 2008; executive vice president-corporate development and strategy and general counsel from 2002 to 2006, and senior vice president, general counsel and chief ethics officer from 2000 to 2002. Before his tenure at Exelon, Mehrberg was an equity partner in the Chicago law firm of Jenner & Block, where he worked from 1980 to 1993 and again from 1997 to 2000. He represented corporations, individuals, not-for-profits and government entities in a broad range of matters. From 1993 to 1997 he served as lakefront director and general counsel for the City of Chicago's Park District. He has been active in a number of business and civic organizations, including serving as vice chairman of the board of Nuclear Electric Insurance Limited and as a board member of both the University of Pennsylvania Medical School and the University of Michigan Law School. Mehrberg has been the recipient of numerous awards, such as the AJC Judge Learned Hand Human Relations Award, the Mexican-American Legal Defense and Education Fund Legal Services Award, the Chicago Bar association David C. Hilliard Award, the Catholic Charities Award for Service to the Poor, and the H.O.P.E. for the People Award – Man of the Year.	Mehrberg holds a Doctor of Law degree from the University of Michigan Law School and a Bachelor of Science degree in economics magna cum laude from the University of Pennsylvania's Wharton School of Business.
Margaret M. Pego	Senior Vice President - Human Resources and Chief Human Resources Officer	PSEG Services Corporation	Margaret M. Pego was named senior vice president – human resources and chief human resources officer of PSEG Services Corporation, in December 2006. Prior, she had been vice president – human resources. Ms. Pego joined PSEG in 1974, and has held a variety of management positions in the human resources department. Ms. Pego is active in several local and national organizations; including the EEI Chief HR Executives Policy Committee; the American Gas Association HR Policy Committee; The Conference Board Advisory Council of HR Management – Council of HR Executives; Center for Energy Workforce Development (CEWD) Executive Counsel Chair; and the Society for Human Resources Management. She is a former member of the Supreme Court of New Jersey Attorney Ethics Committee. Ms. Pego is a 2002 Leadership New Jersey graduate, a 1997 TWIN Honoree, 2006 Executive Woman of New Jersey Honoree and 2008 NJ Best 50 Women in Business Honoree. In addition, she is a member of the board of trustees of the American Conference on Diversity, the Boys and Girls Club Concert for Kids Committee, College of Saint Elizabeth, Leadership New Jersey, Rutgers Business School and the Children's Specialized Hospital.	Ms. Pego holds a Bachelor of Arts degree in business administration from William Paterson College, and a Master of Business Administration degree with a concentration in management and labor relations from Seton Hall University. In addition, she holds a certificate in EEO studies from Cornell University, and has also completed the Human Resources Executive Program at the University of Michigan. She is also certified as a senior professional in human resources.

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R. Edwin Selover	Executive Vice President and General Counsel	PSEG, PSE&G, PSEG Services Corporation, PSEG Power	R. Edwin Selover was named executive vice president and general counsel of Public Service Enterprise Group Incorporated (PSEG), in December 2006. He had been senior vice president and general counsel since April 2002, and vice president and general counsel since April 1988. In addition, Mr. Selover has been senior vice president and general counsel of Public Service Electric and Gas Company (PSE&G), since January 1988, and PSEG Services Corporation since November 1999 - both subsidiaries of PSEG. Mr. Selover joined PSEG as an attorney in 1972 and currently heads the law department, internal audit services and corporate public affairs, which includes corporate communications and advertising, state governmental affairs and federal affairs and policy. Mr. Selover is a director/trustee for New Jersey Future and the New Jersey Conservation Foundation, and is on the advisory board of the Mid-Atlantic Legal Foundation.	A native of Oklahoma, Mr. Selover served in the United States Army and graduated from Union College, Schenectady, New York. He also received his Doctor of Law degree from the University of Minnesota School of Law.
Elbert C. Simpson	President and Chief Operating Officer	PSEG Services	Elbert C. Simpson was named president and chief operating officer of PSEG Services Corporation, in December 2006. Previously he was senior vice president - information technology and chief information officer. Mr. Simpson has a 30-year career in the nuclear energy field, as well as a proven ability to manage complex projects on tight timelines. Formerly, he was the senior vice president and chief administrative officer of PSEG Nuclear where he oversaw the business support organizations; including business planning, finance, and supply chain management. Prior to this position he was the senior vice president of nuclear engineering, where he oversaw all engineering activities for the Salem and Hope Creek units. Currently, Mr. Simpson oversees corporate security, claims, human resources, environmental health and safety (EH&S), supply chain management, and information technology. Prior to joining Public Service Electric and Gas Company (PSE&G) Mr. Simpson was vice president - nuclear support for Arizona Public Service Company (APS), which operates the three-unit Palo Verde Nuclear Generating Station. In this capacity he was responsible for nuclear training, licensing, materials, contracts, emergency planning, records management, environmental protection and safety. He joined APS in 1990 as the vice president - nuclear engineering and was responsible for all engineering functions in support of Palo Verde station. Mr. Simpson assumed the position of vice president - nuclear support in 1993. He also held a number of managerial positions with Florida Power Corporation, including director - nuclear operations engineering and projects, director - nuclear operations site support, and director - nuclear operations engineering and licensing.	Mr. Simpson holds Bachelor of Science degrees in electrical engineering and nuclear engineering from the University of Florida.
Jorge L. Cardenas	Vice President – Gas Operations	PSE&G	Jorge L. Cardenas was elected vice president – gas operations of Public Service Electric and Gas Company (PSE&G), in December 2006. In this role he is responsible for providing gas delivery and appliance repair services to three quarters of New Jersey's population, overseeing the work of more than 2,000 associates. Previously, Mr. Cardenas was division manager – gas delivery, directing the construction, operation, and maintenance of the gas distribution system in Northern New Jersey. His career spans over 30 years at PSEG, having held various positions in gas delivery, electric delivery and corporate services. Throughout his career at PSE&G, Mr. Cardenas has been a champion for health and safety in the workplace and was named chairman of the New Jersey State Safety Council in 2007. Active in volunteer efforts, he has been a leader in promoting participation in March of Dimes activities for the last 15 years. He was named chairman of the March of Dimes Essex County Walk America from 2005 to 2007. He was also named a member of the March of Dimes board of directors for New Jersey in 2007. Mr. Cardenas is a member of the Society of Gas Operators, a member of the Leadership Council of the American Gas Association, and serves on the board of directors of the Northeast Gas Association and Operations Technology Development. He was honored with a New Jersey Minority Achiever's Award in 2004, and selected to attend the Leadership New Jersey program in 2000.	Mr. Cardenas received his bachelor's degree in engineering from the Stevens Institute of Technology, and completed the Penn State Executive Development Program. He received his Master of Business Administration degree from Rutgers University's Executive MBA program. As part of his MBA, he studied international business at Cambridge University in England.

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David M. Daly	Vice President – Asset Management and	PSE&G	David M. Daly was named Vice President - asset management and centralized services at Public Service Electric and Gas Company (PSE&G) in June 2009. Prior to this position, Mr. Daly was vice president – energy acquisition and technology for PSE&G, responsible for managing the Utility's default electric and gas supply functions, and for leading PSE&G's implementation of a new customer information system, gas appliance service work management system, and meter data management system. Previously, Mr. Daly has held a variety of positions in utility operations and support services areas, including: director – iPower, division manager – merger integration, division manager – southern electric operations, director – utility operations services, director – enterprise strategy, and general manager – transmission planning and services. Upon joining PSE&G in 1983, he held various first and second line supervisory positions in PSEG's fossil power generation organization. Earlier in his career, Mr. Daly was a senior consultant at Metzler & Associates, as well as the UMS Group, where he focused on performance management and benchmarking, process reengineering, and competitive strategy development. He serves on the board of directors of the Independent College Fund of New Jersey, a non-profit organization focused on the advancement of independent higher education and programs to assure access to diverse educational opportunities.	Mr. Daly has an electrical engineering degree from the State University of New York Maritime College, and a Master of Business Administration degree from Rutgers University.
Joseph A. Forline	Vice President - Customer Operations	PSE&G	Joseph A. Forline was elected vice president - customer operations of Public Service Electric and Gas Company (PSE&G), in December 2006. Prior, he was division manager - gas operaitons at PSE&G. He is responsible for Utility Marketing, Economic and Community Development, Customer Contact Centers, and Billing Operations. Mr. Forline has worked for PSE&G for over 24 years, in areas such as gas distribution, gas engineering, electric street lighting and metering operations, and appliance services. He has played a key leadership role in PSE&G's total quality programs, WorryFree contract expansion, gas construction efficiency efforts, and damage prevention programs. Mr. Forline is member of the PSEG executive steering committees for employee benefits and the political action committee. He is active in industry Associations with the American Gas Association, the Edison Electric Institute, and Customer Service Week. Mr. Forline is a member of the board of advisors for the Rutgers Camden School of Business, the board of directors for the March of Dimes Southern New Jersey chapter, a board member for the United Way of Burlington County and has recently been appointed to the Board of Trustees for the Cooper Hospital Foundation in Camden. He is a graduate of the Leadership New Jersey Program, class of 2006. Forline is active in youth athletics in the areas of basketball, football, and baseball. He is a former	Mr. Forline has a Bachelor of Science degree in engineering from Rutgers University - College of Engineering, and a Masters of Business Administration degree from Rutgers Univeristy. He is also a graduate of the University of Michigan Executive Development Program.
Mark G. Kahrer	Vice President – Finance, PSE&G	PSE&G	Mark G. Kahrer was elected vice president – finance for Public Service Electric and Gas Company in June 2009. He was previously vice president – finance and development of PSEG Power, since May 2005. Mr. Kahrer is responsible for strategic planning, financial analysis, reporting, forecasting and the balanced scorecards and benchmarking, as well as analyzing the development activities for PSE&G. In June 2009, Mr. Kahrer also assumed responsibility for the BGS and BGSS processes within PSE&G as well as PSE&G's Retail Settlement Unit. Previously, Mr. Kahrer was assistant treasurer of Public Service Enterprise Group Incorporated (PSEG), responsible for directing the corporate finance department, capital market transactions, and daily oversight of the company's pensions, trusts, and insurance programs. He joined PSEG in 1983 as an accountant and has held the positions of director – corporate accounting, director – financial risk management, manager – corporate strategic planning, and manager – federal affairs. He is the treasurer of PEGPAC, PSEG's political action committee, a regent of Saint Peter's College and Secretary of the Hudson Catholic High School Board of Consultors. Mr. Kahrer is also a past president of the Saint Peter's College Alumni Association board of trustees and the former treasurer of the ARC of Essex County Foundation Board.	Mr. Kahrer is a certified public accountant, holds a Bachelor of Science degree in accounting from Saint Peter's College, and a Master of Business Administration degree in finance from Seton Hall University.

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Frederick W. Lark	Vice President – Business Analysis	PSE&G	Frederick W. Lark was elected vice president – business analysis for Public Service Electric and Gas Company (PSE&G), in October 2000. Mr. Lark has been with PSE&G since 1963, holding posts of increasing responsibility. He served as general manager – rates and load management, and general manager – rates and market planning, before his election as vice president – marketing in January 1990. From March 1999 until October 2000, he served as vice president – retail systems at PSEG Energy Technologies. Mr. Lark is a member of the Society of Gas Lighting.	Mr. Lark earned a Bachelor of Science degree in electrical engineering from Lehigh University and a Master of Business Administration degree from Rutgers University. He has also completed the Harvard Graduate School of Business Administration's Program for Management Development.
John R. Latka	Vice President – Electric Operations	PSE&G	John R. Latka was named Vice President-Electric Operations for Public Service Electric and Gas Company (PSE&G), in October 2006. In this position, he oversees PSE&G's electric system operations, safety, and emergency preparedness efforts to provide safe, reliable service to the utility's 2.1 million electric customers. He had previously been Director-Electric System Operations. PSE&G has received the ReliabilityOne Award for the Mid-Atlantic region for seven consecutive years and was recognized as America's most reliable electric utility by a major industry benchmarking group in 2004, 2005 and 2007. Since joining PSE&G in 1982, Mr. Latka has held various positions, including assignments in the International Brotherhood of Electrical Workers, transmission, distribution operations, construction, engineering and emergency preparedness.	Mr. Latka holds a bachelor's degree in education from Tennessee Technological University. He is currently a board member for the Commerce and Industry Association of New Jersey.
Alfredo Z. Matos	Vice President – Renewables and Energy Solutions	PSE&G	Alfredo Z Matos was named vice president – renewables and energy solutions of Public Service Electric and Gas Company (PSE&G), in January 2008. In this position he helps the utility explore new opportunities in the renewable energy and conservation markets. His responsibilities include finding solar, energy efficiency and other renewable projects to help meet the New Jersey Energy Master Plan objectives. Previously, Mr. Matos had been vice president - distribution operations and EHS of PSEG Global (Global), since 2004. He had also been vice president – distribution performance, since 2002, and general manager - strategic operations for PSEG Americas - a subsidiary of Global that focuses on Latin America, since 1997. Mr. Matos joined PSEG in 1981 and has acquired vast experience in domestic and international electric distribution, including regional and field management responsibility in the gas and electric distribution business in New Jersey. His experience in the electric distribution business includes managing field operational resources, network planning, project management, engineering and construction. He also worked as part of the Hope Creek nuclear plant engineering team, where he gained valuable experience in nuclear plant generation start-up and control systems, between 1981 and 1985. Mr. Matos had been with Global since 1997, after an 18-month international assignment. His experience focused on the operational due diligence processes of potential target investments, managing the takeover processes of newly acquired operating companies, and maximizing existing distribution operating performance. In 2004 he acquired asset management and P&L responsibility for the Latin American distribution businesses, and was the chief environmental, health and safety officer. Mr. Matos is a recipient of the New Jersey Governor's Volunteerism Award and continues to serve the community on athletic and civic boards, including serving as an elected member to the Randolph Township Board of Education, and is also a Eucharistic minister at his church. Mr. Matos is bilingual in English and Spanish.	He received his undergraduate degree in engineering, and a MBA in Finance from Drexel University in Philadelphia.

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Frances I. Sundheim	Vice President – Corporate Rate Counsel	PSE&G	Frances I. Sundheim was named vice president – corporate rate counsel of Public Service Electric and Gas Company (PSE&G), in December 2006. Previously she was assistant corporate rate counsel. Ms. Sundheim joined PSEG in 1995 as an attorney in the office of Corporate Rates Counsel. Prior to joining PSEG, she served in several positions in the New Jersey Division of Rate Counsel in the Department of the Public Advocate - including deputy director and acting director. She also served as acting director of the Division of the Ratepayer Advocate. Other positions that Ms. Sundheim has held with the State of New Jersey include supervisor - regulatory unit at the New Jersey Department of Transportation, and Deputy Attorney General - Department of Law and Public Safety, Division of Gaming Enforcement. She also served as a judicial law clerk at the Office of Administrative Law. Ms. Sundheim is a member of the New Jersey Bar. She is currently active in the New Jersey Bar Association, and has served as president of the Public Utility Law Section. She has been chairperson of the section's spring conference, and has moderated various bar association panels.	Ms. Sundheim was awarded a Bachelor of Arts degree from Fairleigh Dickinson University, Madison, New Jersey in english and education, and a Juris Doctor degree from the Rutgers University School of Law, Camden, New Jersey.
Stuart J. Black	Vice President – Internal Auditing Services	PSEG Services Corporation	Stuart J. Black was elected vice president – internal auditing services for PSEG Services Corporation, in January 2005. He previously served as director – internal audit services. Mr. Black is responsible for providing independent and objective assurance, and internal control advisory services to PSEG and its subsidiaries. These services are designed to evaluate and improve the effectiveness of the company's risk management, control and governance processes. With the recent enactment of the Sarbanes-Oxley Act, he also is charged with assisting management in complying with the law's Section 404, which involves internal controls for financial reporting. Mr. Black came to PSEG in March 2002. Previously he was employed at Honeywell International (1995-2002), a diversified manufacturing conglomerate, in a number of positions - the most recent of which was controller of the global business services unit. Prior to that he was a senior manager at KPMG (1984-1995), a major public accounting firm.	Mr. Black has a Bachelor of Arts degree in business administration from Rutgers University and is a certified public accountant in New Jersey.
Anne E. Hoskins	Vice President – Federal Affairs and Policy	PSEG Services Corporation	Anne E. Hoskins was named vice president – federal affairs and policy of PSEG Services Corporation, in April 2007. In this position, she is responsible for PSEG's federal governmental affairs, and leaders' role in the development of public policy positions on issues affecting the company and its operations in the United States. Prior to joining PSEG, Ms. Hoskins served as senior and regulatory counsel for Verizon Wireless, working from offices in Washington and New Jersey. Ms. Hoskins also served as an associate in the Newark law firm of McCarter and English, an attorney in the United States Office of the Comptroller of the Currency, and as Policy Adviser in the Governor's Office of Policy and Planning in New Jersey.	Ms. Hoskins holds a Doctor of Law degree from Harvard Law School, a Master of Public Affairs degree from the Woodrow Wilson School at Princeton University, and a Bachelor of Science degree from Cornell University.
Shawn P. Leyden, Esq.	Vice President – Corporate and Commercial	PSEG Services Corporation	Shawn P. Leyden, Esq., was named vice president - corporate and commercial for PSEG Services Corporation, in December 2006. Previously, he had been vice president and general counsel of PSEG Energy Resources and Trade, since 2002. Mr. Leyden also served as vice president and general counsel of PSEG Energy Technologies Incorporated, and prior to that he was an attorney and general energy services counsel for Public Service Electric and Gas Company. Mr. Leyden has specialized in energy law and federal/state energy regulation, including issues related to the business structure and implementation of utility and non-utility energy services and business opportunities. He has represented PSEG in numerous proceedings involving the full spectrum of administrative litigation at the Federal Energy Regulatory Commission, the New Jersey Board of Public Utilities, and in related appellate proceedings before state and federal appellate courts. Mr. Leyden is a member of the Federal Energy Bar Association, the American Bar Association and the New Jersey State Bar Association. He is admitted to the State Bar of New Jersey, the Federal District Court of New Jersey, the United States Court of Appeals for the Third Circuit and the United State Court of Appeals of the Fifth Circuit. He is also a member of the board of trustees of the North New Jersey Affiliate of the Susan G. Komen Breast Cancer Foundation, and a former member of the board of trustees of the Hospital Center at Orange.	Mr. Leyden joined PSEG in 1983 after service in the Office of the Attorney General, Division of Criminal Justice, State of New Jersey. He received his Bachelor of Arts degree from Seton Hall University and his Doctor of Law degree from Seton Hall University School of Law.

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Tamara L. Linde	Vice President - Regulatory	PSEG Services Corporation	Tamara L. Linde was named vice president - regulatory of PSEG Services Corporation, in December 2006. She is responsible for the federal and state regulatory matters of the PSEG companies. Ms. Linde joined the law department of Public Service Electric and Gas Company (PSE&G), as an attorney in 1990 handling a variety of natural gas and electric regulatory and transactional matters. After holding several other legal positions at PSE&G she became general solicitor, in 2000. In that position she was responsible for the regulatory affairs of the PSEG companies including electric, gas and nuclear matters. Ms. Linde is a member of the New Jersey, New York and District of Columbia bars. She is also an active member of the Energy Bar Association and a member of the American Bar Association Public Utility Law Section.	Ms. Linde graduated from Seton Hall University School of Law and from Seton Hall University with a bachelor's degree.
J. Brian Smith	Vice President – Communications and Advertising	PSEG Services Corporation	J. Brian Smith was named vice president – communications and advertising for PSEG Services Corporation, in February 2007. Previously, he was director – corporate communications and director – investor relations. Mr. Smith joined PSEG in 1976 and has held various positions, including manager – corporate communications and manager – investor relations. Prior to joining PSEG, Mr. Smith was a reporter and editor for the New York Daily News and previously worked as a reporter for the Newark, NJ, Evening News. Mr. Smith has also been an adjunct professor in communications at Ramapo College of New Jersey.	Mr. Smith holds a Bachelor of Arts degree in communication arts from Seton Hall University and a Master of Arts degree in media studies from the New School for Social Research in New York. He has been active in several communications and investor relations organizations.
Richard T. Thigpen	Vice President – State Governmental Affairs	PSEG Services Corporation	Richard T. Thigpen was named vice president – state governmental affairs of PSEG Services Corporation, in March 2007. He has been a public affairs consultant since 1999 and was a co-founding partner of 1868 Public Affairs LLC, which provides lobbying, strategic planning, public relations and government relations services to clients in New Jersey, New York and Washington, D.C. Previously, Mr. Thigpen served as an associate at the New York law firm of Thacher Proffitt and Wood in the mortgage-backed securities practice group (1988 to1990), and was the district director for Congressman Don Payne (NJ-10) (1990 to 1996). Mr. Thigpen was also the executive director of the New Jersey Democratic State Committee (1996 to 1999), where he coordinated two successful statewide campaigns for both national and New Jersey candidates.	Mr. Thigpen holds a Doctor of Law degree from Columbia University School of Law in New York and is a graduate of Brown University in Rhode Island.
Frank C. Ameo	Vice President – Engineering and Operations Support	PSEG Power	Frank C. Ameo was named vice president – engineering and operations support for PSEG Power, in February 2007. Previously he was director of PSEG Fossil's service company (SERVCO). Under Mr. Ameo's leadership SERVCO's outage performance in Nuclear and Fossil improved significantly in the areas of cost and schedule adherence. During this same time period, employee safety improved to top quartile and rework down to its lowest levels. In this new position, Mr. Ameo will oversee engineering support, project management and outage management across the entire fossil system, while continuing to provide specialized maintenance services for fossil and nuclear generating stations. Mr. Ameo joined PSEG in 1980 as an associate engineer, and advanced through a variety of leadership positions throughout fossil operations and maintenance as well as corporate assignments. His experience encompasses all fossil technologies including coal fired, combined cycle and peaking operation. Mr. Ameo was a key team member negotiating a long term service agreement with a key supplier. He also led and participated in several labor contract negotiations. He is a member of the Electric Power Research Institute (EPRI) Generation Council.	Mr. Ameo has a bachelor's degree in industrial engineering and a Master of Business Administration degree, both from Fairleigh Dickinson University.

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George P. Barnes, Jr.	Senior Vice President – Power Technology, Development and Construction	PSEG Fossil	George P. Barnes, Jr. was named Senior Vice President – Power Technology, Development and Construction for PSEG Fossil, in August 2009. Prior to his new position, he was site vice president – Hope Creek, PSEG Nuclear. He assumed the role of PSEG Nuclear's site vice president, as part of the Nuclear Operating Services Agreement between PSEG and Exelon Corporation. Mr. Barnes has more than 36 years of military and commercial nuclear power plant experience. Prior to coming to PSEG, he was site vice president at Exelon Nuclear's LaSalle County Generating Station – a position he held since January 2002. At Exelon, he had held increasing positions of responsibility, including Quad Cities' plant manager. Mr. Barnes also held various management positions while at Carolina Power & Light's (CP&L) Brunswick Nuclear Plant, where he was instrumental in developing and implementing programs that resulted in dramatic station improvements. During his tenure at Brunswick, he was licensed as a senior reactor operator (SRO). Mr. Barnes also served as plant manager at CP&L's W.H. Weatherspoon fossil plant.	Mr. Barnes earned a Bachelor of Science degree in business administration from the University of North Carolina.
Robert C. Braun	Vice President – Salem	PSEG Nuclear	Robert C. Braun was named vice president – Salem for PSEG Nuclear, in June 2007. He had been vice president – operations support, since March 2007. Previously, Mr. Braun was site vice president of Exelon Corporation's Peach Bottom Atomic Power Station. Prior to his appointment at Peach Bottom, he was vice president – nuclear oversight of Exelon's nuclear group headquarters and previously served as plant manager of the company's Limerick Generating Station, where he held a senior reactor operator license. Mr. Braun began his career at Limerick in 1982.	Mr. Braun has a Bachelor of Mechanical Engineering degree from Villanova University.
John Paul Cowan	Vice President – Fossil Operations	PSEG Fossil, LLC	John Paul Cowan was named Vice President-Fossil Operations in August 2009. Mr. Cowan joined PSEG in January 2009 as Director-Fossil Programs and Efficiency. Prior to joining PSEG as an employee, Mr. Cowan provided Consultant Services to PSEG Fossil, LLC and PSEG Power, LLC. In these roles, Mr. Cowan served as the Executive Director for PSEG's New Nuclear Plant Development reporting to Bill Levis. Mr. Cowan also consulted to the President, PSEG Fossil, LLC for initial implementation of the Fossil Operational Excellence Model (OEM). Prior to joining PSEG, Mr. Cowan held several executive positions including Executive Vice President and Chief Nuclear Officer-Nuclear Management Company, Vice President and Chief Nuclear Officer-Florida Power Corporation, Vice President Environmental Services-Carolina Power and Light, and Vice President-Operation Services for Carolina Power and Light. Mr. Cowan has worked for the Institute of Nuclear Power Operations (INPO) as a department head, assistant to the Chief Executive Officer and Secretary to the Board of Directors. He also spent 10 years with General Electric in technical, operational, and management positions. He is currently an active member of the Georgia State Bar Association and the American Bar Association. He is a recipient of the University of Wisconsin's Distinguished Service Award and has been a member of several electric industry groups including the Institute of Nuclear Power Operations, Nuclear Electric Institute, and Electric Power Research Institute.	Mr. Cowan is a graduate of the University of Wisconsin- Madison with a Bachelor's Degree in Nuclear Engineering. He has a Master's Degree in Business Management from Rensselaer Polytechnic Institute, and a Juris Doctor's Degree from Georgia State University.

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Daniel J. Cregg	Vice President – Finance Power	PSEG Services Corporation	Daniel J. Cregg was named vice president – finance power for PSEG Services Corporation, in December 2006. Prior to this appointment he was director – financial reporting and communications at PSEG Power (Power), where he oversaw financial reporting and forecasting, investor communications, financings, rating agency interactions, external reporting, and cash forecasting. He previously held leadership positions with Power in the areas of financial valuations, competitive intelligence, and fundamental market modeling; with critical responsibilities in Power's development and strategic planning activities. Previously, Mr. Cregg was director of PSEG corporate development. He joined PSEG in 1991 with overall responsibility for tax planning, strategy and compliance for PSEG Energy Holdings, including domestic and international tax structuring work for PSEG Global and PSEG Resources. Prior to joining PSEG Mr. Cregg spent five years with the accounting and consulting firm of Deloitte and Touche, providing consulting services to a wide array of clients with an emphasis on the energy industry. Mr. Cregg has been involved in raising awareness and funding for Sudden Infant Death Syndrome (SIDS) for the last ten years. He is also an executive sponsor for Power's diversity council and is a member of PEGPAC, PSEG's Political Action Committee.	Mr. Cregg holds a Master of Business Administration degree from the Wharton School of the University of Pennsylvania and is a graduate of Lehigh University, where he received a bachelor's degree in accounting.
Raymond V. DePillo	Vice President – Power Operations and Asset Management	PSEG Energy Resources & Trade	Raymond V. DePillo was named a Vice President in PSEG Energy Resources & Trade, in February 2006. Mr. DePillo joined PSEG in 1992 and served as managing director – energy trading since 2005. Previously, he held various management positions within Energy Resources & Trade, becoming an energy trader in 1997.	Mr. DePillo is a graduate of Villanova University and has a Master of Business Administration degree from the Rutgers Graduate School of Management.
Carl J. Fricker	Vice President – Operations Support	PSEG Nuclear	Carl J. Fricker was named vice president – operations support of PSEG Nuclear, in June 2007. He had been the Salem plant manager since August, 2003. Mr. Fricker joined PSEG in April 1995. Prior to his position as plant manager, he held management positions in operations, maintenance, and quality assessment. Mr. Fricker has over 22 years of military and commercial nuclear power plant experience. Prior to joining PSEG he worked for the Washington Public Power System, Westinghouse, Florida Power and Light (FPL), and was a commissioned officer in the United States Navy. While with FPL, he obtained a Senior Reactor Operators license at the Turkey Point Nuclear Power Plant.	Mr. Fricker earned a Bachelor of Science degree from the United States Naval Academy and a Master of Business Administration degree from the University of Delaware.
John F. Perry	Vice President – Hope Creek	PSEG Nuclear	John F. Perry was named vice president – Hope Creek for PSEG Nuclear, in August 2009. He had been plant manager - Hope Creek since 2007. Prior to that, he was maintenance director at Hope Creek since joining PSEG in 2005. Previously, Mr. Perry was maintenance director for AmerGen/Exelon at the Limerick Nuclear Generating Station and he held prior positions at the Oyster Creek and Three Mile Island facilities.	Mr. Perry has a Bachelor of Social Science degree from Penn State University; has additional post graduate credits in the areas of accounting, labor relations and public administration; and completed the ANSI 3.1 Senior Reactor Operator (SRO) Certification in 2003.
David W. Wohlfarth	Vice President – Gas Supply	PSEG Energy Resources and Trade	David W. Wohlfarth was named vice president – gas supply of PSEG Energy Resources and Trade (ER&T), in December 2006. Mr. Wohlfarth was previously managing director - gas and fuel supply at ER&T, since 2005. In this position he had overall P&L responsibility for the gas contract portfolio of ER&T, including responsibility for long term capacity acquisition and restructuring, gas trading, and regulatory matters related to gas supply and price issues before the Federal Energy Regulatory Commission. He also had oversight of oil and coal supplies for PSEG Power's generation fleet. Mr. Wohlfarth joined PSEG in 1968 and has held various positions, including president - Energy Development Corporation (EDC), PSEG's oil and gas exploration subsidiary, and Gasdel Pipeline Incorporated, EDC's interstate gas pipeline subsidiary. Mr. Wohlfarth is a member of the board of visitors, chemical and petroleum engineering department, School of Engineering at the University of Pittsburgh. He was a recipient of the University of Pittsburgh School of Engineering's 2006 Distinguished Alumnus Award.	Mr. Wohlfarth graduated from the University of Pittsburgh with a Bachelor of Science degree in petroleum engineering and received his Masters of Business Administration degree from Rutgers University.

Name of Officer	Title	Organization	Experience	Education
Eileen A. Moran	President	PSEG Resources	Eileen A. Moran is president of PSEG Resources and chair of PSEG's pension and nuclear decommissioning trust fund committees. Ms. Moran had been senior vice president – strategic initiatives of PSEG Services Corporation, until December 2008. She held that position while retaining her positions as president of PSEG Resources (effective May 1990) and president of the Enterprise Group Development Corporation (EGDC) (effective January 1997). Ms. Moran joined Public Service Electric and Gas Company (PSE&G) in 1977 and has held a number of positions in the finance and investment areas of PSE&G, including that of assistant treasurer. She also served as vice president – investments of Resources from 1986, until her election as president. Ms. Moran is a board member of Duff & Phelps Utility and Corporate Bond Trust; DTF Tax - Free Income Fund; the DNP Select Income Fund, and member of the valuation committee for Edison Venture Funds III, IV & V. She also is a member of the Benedictine Academy Advisory Board.	Ms. Moran received a Bachelor of Science degree in business administration from Seton Hall University and a master's and doctorate degrees in economics from Fordham University. She also completed the Harvard Graduate School of Business Administration's Program for Management Development.
Laura L. Brooks	Vice President - Risk Management and Chief Risk Officer	Public Service Enterprise Group Incorporated	Laura L. Brooks was appointed vice president - risk management and chief risk officer (CRO) for PSEG, in November 2002. She implements PSEG's enterprise risk management strategy and recommends methodologies for assessing and evaluating risk across all PSEG businesses. She has direct responsibility for the middle office functions of the trading subsidiary of PSEG Power, Energy Resources & Trade. Ms. Brooks is an integral member of the risk management committee, which is responsible for managing the company's exposure to commodity prices, credit, interest rate and other financial risks. Ms. Brooks came to PSEG from PG&E Corporation, where she had been vice president - risk management. She currently serves on the advisory board for the quantitative finance program at Rutgers University, is a director of Provident Financial Services and the Provident Bank of New Jersey, and also serves on the board of the Girl Scouts heart of New Jersey. Ms. Brooks was previously employed at Deloitte & Touche as a senior manager; at Equitable Resources as director - corporate risk management; at Equitrans, an interstate pipeline, as vice president - reservoir engineering; and at Southern California Gas Company as a senior engineer.	Ms. Brooks has Master of Science degrees from both Carnegie Mellon University and Stanford University, and Master of Arts and Bachelor of Arts degrees from the University of Colorado.
Derek M. Di Risio	Vice President and Controller	Public Service Enterprise Group Incorporated Public Service Electric and Gas Company PSEG Services Corporation PSEG Energy Holdings PSEG Power	Derek M. Di Risio was named vice president and controller of Public Service Enterprise Group (PSEG), Public Service Electric and Gas Company (PSE&G), PSEG Services Corporation, PSEG Energy Holdings (Holdings) and PSEG Power, in December 2006. He was previously vice president and assistant controller, since July 2004. Mr. Di Risio had been vice president – planning and analysis of Holdings since March 2004, and vice president – controller for Holdings since July 1998. Prior to that he was director – accounting services and responsible for several accounting and planning functions for Holdings, including overall coordination of the business planning process, accounting research and policy development, financial forecasts and analysis. Mr. Di Risio was also responsible for the budgeting, analysis and reporting process for PSE&G. Mr. Di Risio joined PSE&G in September 1991 and has held a variety of positions, including assignments with the internal auditing, electric business, and corporate planning departments. He was instrumental in reengineering the Enterprise business planning process, and advancing the use of performance metrics and balanced scorecard measures to improve business results. Prior to joining PSE&G he worked for several firms, including Chase Manhattan Bank.	Mr. Di Risio graduated from Rutgers University with a degree in accounting/computer science, and received a Master of Business Administration degree from the same university. He is a certified public accountant and a certified internal auditor. Mr. Di Risio also completed the Program for Management Development at the Graduate School of Business Administration of Harvard University.
Nelson Garcez, Jr.	Vice President – Generation and Technical Services	PSEG Global	Nelson Garcez, Jr. was appointed vice president – generation and technical services of PSEG Global (Global) in 2003, being responsible for Global's domestic and international generation fleet. He had been vice president - Europe and North Africa, since January 2002. Mr. Garcez joined Global in August 1997 in Brazil, and has held a variety of positions in business development and asset management; including country management in Brazil (1998/99), business management for the Mercosur region (2000), and business management for Europe, North Africa and the Middle East (2001). Prior to joining Global Mr. Garcez worked for South America's largest electricity distribution utility, Eletropaulo, where he was responsible for strategic planning and capital investments. He also was the executive director of the Sao Paulo State Energy Development Agency, and a member of the board of directors of Sabesp, the water utility of the state of Sao Paulo.	Mr. Garcez graduated from the Polytechnic School of Sao Paulo State University, Brazil, with a degree in mechanical engineering, and completed post-graduate studies in energy planning at the same university. He has also completed the Harvard University/Kennedy School of Government program of privatization and restructuring of the energy sector, and the Getulio Vargas Business School program on marketing of services.

Name of Officer	Title	Organization	Experience	Education
Michelle Hallerdin	Vice President – Strategic Planning and Finance	PSEG Global	Michelle Hallerdin was named vice president – strategic planning and finance for PSEG Global, in January 2008. Previously, she was vice-president – workforce planning and talent management for PSEG Services Corporation, since 2006. Ms. Hallerdin had also been director – workforce planning and strategy, where she was responsible for assessing, creating, implementing and evaluating solutions to diminish gaps between PSEG's current state, PSEG's business objectives, and the changing nature of the workforce. She also prepared the organization to meet the needs of workers and work into the future. Prior, Ms. Hallerdin was manager – Enterprise strategy, responsible for developing and implementing frameworks to challenge and refine PSEG strategies and business planning processes. She has held various financial, marketing and business planning roles with PSEG Energy Technologies Ms. Hallerdin is currently a board member of the Newark, New Jersey, YMWCA.	She has a Bachelor of Arts degree from the University of Delaware and a Master of Business Administration degree from Emory University.
Scott S. Jennings	Vice President – Mergers, Acquisitions and Development Public Service Enterprise Group Incorporated President PSEG Global	Public Service Enterprise Group Incorporated; PSEG Global	Scott S. Jennings was named President of PSEG Global in June 2009. He also serves as vice president – mergers, acquisitions and development of Public Service Enterprise Group Incorporated (PSEG), a position he's held since November 2007. In this capacity he is responsible for exploring multiple strategic growth opportunities. Previously, Mr. Jennings was vice president - finance, responsible for analyzing PSEG Global's portfolio which resulted in the refinancing or sale of various international assets. He also oversaw the business planning process, financial forecasting and the development of new management reporting tools for the portfolio and its projects. Prior to this appointment Mr. Jennings served as assistant controller, where he was primarily responsible for the accounting, internal controls and reporting functions related to PSEG Holdings. Mr. Jennings has worked at PSEG in the accounting services area since joining the company in 1998. He also served as director – corporate accounting. During his tenure Mr. Jennings was at the center of a number of accounting issues related to Public Service Electric and Gas Company's (PSE&G) deregulation, reorganization, and financing of its affiliates and various corporate development transactions. He spent five years with Deloitte & Touche in their New Jersey office, working primarily with financial services firms and the public utility industry. Recently, Mr. Jennings completed his tenure as chairperson of the American Gas Association Corporate Accounting Committee and is also a member of the board of directors of the United Way of Essex and West Hudson Counties, the Aurora Foundation and other civic organizations.	Mr. Jennings has a Bachelor of Business Administration degree and a Master of Business Administration degree in accounting from Pace University, New York. He is a certified public accountant and has participated in various leadership courses, including the High Potential Leadership Program at Harvard University.
Robert C. Krueger, Jr.	Vice President and Assistant Controller - Tax	PSEG Services Corporation	Robert C. Krueger, Jr. was named vice president and assistant controller – tax of PSEG Services Corporation, in December 2006. He had been director – financial planning and analysis since 1999. In that position he was responsible for business forecasting and budgeting, as well as establishing accounting and tax strategies for PSEG. Mr. Krueger had previously been director - tax services, since 1992. He joined Public Service Electric and Gas Company in 1988 as Principal Tax Accountant. Prior to joining PSEG, Mr. Krueger was employed by Deloitte, Haskins and Sells (DH&S), mainly in its tax department. He worked on a variety of tax engagements for both regulated and non-regulated businesses and ultimately joined DH&S's utility tax specialty group Mr. Krueger is a member of the American Institute of Certified Public Accountants and the New Jersey State Society of Certified Public Accountants. In 2002 he was appointed by the Governor of the State of New Jersey to the New Jersey Corporate Business Tax Study Commission.	Mr. Krueger graduated from Bucknell University with a Bachelor of Science degree in business administration - accounting, and he earned a Master of Business Administration degree from Lehigh University. He has been a licensed certified public accountant in the State of New Jersey since 1985.
Kathleen A. Lally	Vice President – Investor Relations	Public Service Enterprise Group Incorporated	Kathleen A. Lally was named vice president – investor relations of Public Service Enterprise Group Incorporated (PSEG), in January 2007. Prior to joining PSEG Ms. Lally was a portfolio manager at the investment firm of Angelo Gordon & Company. She has extensive and diverse Wall Street experience, on both the buy side as an investor and sell side as an equity research analyst. She has worked on the buy side at JK Utility Advisory and Silcap, and has sell side experience at firms such as Salomon Brothers, Brown Brothers Harriman and Pershing.	Ms. Lally holds a Bachelor of Arts degree in political science from St. Peter's College and is a chartered financial analyst.

Name of Officer	Title	Organization	Experience	Education
Joan C. MacDonald	Vice President – Portfolio Management	PSEG Resources	Joan C. MacDonald was elected vice president – portfolio management of PSEG Resources in April 1996. Her principal duties include due diligence and analysis of investment opportunities and portfolio management. Ms. MacDonald began employment with Public Service Electric and Gas Company (PSE&G) in 1986 as a staff auditor in the internal audit department, where she earned her certified internal auditor designation. She joined PSEG Resources in 1988 and had served in numerous capacities until her election as vice president and treasurer in 1996. Prior to her employment with PSE&G, she was employed by First Fidelity Bank Corporation and The Commodities Exchange. Ms. MacDonald is a corporate co-sponsor of PSEG's membership in NAWMBA's (National Association of Women MBA's). She also acts as a mentor-leader in PSEG's corporate mentoring program.	Ms. MacDonald is a certified public accountant. She received a Bachelor of Science degree in economics and accounting from Cook College and a Master's of Business Administration degree with a concentration in finance from Rutgers University.
William J. Metzger	Vice President and Assistant Controller - Power	PSEG Services Corporation	William J. Metzger was named vice president and assistant controller – Power of PSEG Services Corporation, in December 2006. He had been the assistant controller – Power, since 2002. In this role he is responsible for the accounting for all activities of PSEG Power, including trading, settlements, and property accounting. He is also responsible for Enterprise wide derivative accounting policies and procedures. Prior to coming to PSEG Mr. Metzger was controller and chief accounting officer at Covanta Energy Corporation, a $1 billion independent power producer. Prior to that he worked for Deloitte & Touche and the American Institute of Certified Public Accountants (AICPA).	Mr. Metzger holds a Bachelor of Science degree in accounting from the University of Ilinois, and has been a certified public accountant since 1980. He is a member of the AICPA and the Ilinois CPA society.
Morton A. Plawner	Vice President and Treasurer Public Service Enterprise Group Incorporated Vice President and Treasurer Public Service Electric and Gas Company	Public Service Enterprise Group Incorporated; Public Service Electric and Gas Company	Morton A. Plawner was named vice president of Public Service Enterprise Group Incorporated (PSEG), in December 2006. He retained the position of treasurer of PSEG, which he has held since 1998. Mr. Plawner has also been vice president and treasurer of Public Service Electric and Gas Company (PSE&G), since 1998. In 1999 he was elected vice president and treasurer of PSEG Power. Mr. Plawner joined PSE&G in 1969 as an assistant engineer in the electric division. He held various positions in the treasurer's department before being named manager – financial research in 1976. In that capacity he assumed the responsibility for the development and operations of the tactical and strategic corporate modeling programs. Mr. Plawner actively participated in the company's rate case proceedings in the 1970's and 80's, and served on the strategic planning task force in 1985-86. In 1989 he was named risk manager, and became general manager – property and risk management in 1994. He earned the designation of associate in risk management from the Insurance Institute of America in 1992 and completed the advancement program at Duke University in 1994. He is an elected member of the Tau Beta Pi Association. Mr. Plawner has also been a member of the insurance advisory committees of Nuclear Mutual Limited (NML) and Nuclear Electric Insurance Limited (NE L), which are the nuclear industry mutual insurance companies.	Mr. Plawner graduated from the City College of New York with a Bachelor of Engineering degree in mechanical engineering and from Rutgers University with a Master of Business Administration degree.
Kevin J. Quinn	Vice President – Corporate Planning	PSEG Services Corporation	Kevin J. Quinn has been vice president – corporate planning in PSEG Services Corporation, a subsidiary of Public Service Enterprise Group Incorporated (PSEG), since June 2008. Mr. Quinn joined PSEG in 1991 as a business strategy manager in corporate planning. Over the years he worked with the executive officers group to develop corporate strategies and objectives, rising to the position of vice president – corporate planning. Mr. Quinn served as president of PSEG Energy Resources & Trade from December 2006, until returning to the post of vice president – corporate planning in June 2008. Prior to joining PSEG, he was a management consultant for McKinsey and Company Incorporated and an engineer for the Exxon Research and Engineering Company.	Mr. Quinn has a Bachelor of Civil Engineering degree from the University of Dayton and also holds a Master of Business Administration degree from Columbia University.

Name of Officer	Title	Organization	Experience	Education
Cora Brina	Vice President – Human Resources Client Services	PSEG Services Corporation	Cora Brina was named vice president – human resources client services of PSEG Services Corporation, in January 2008. In this role she is responsible for overseeing the planning, directing and implementation of all HR products and services for Public Service Enterprise Group Incorporated (PSEG). Prior, Ms. Brina had been director – human resources for Public Service Electric and Gas Company (PSE&G). In this position she was responsible for planning, directing and implementing HR products and services for PSE&G. Ms. Brina joined PSEG in 1974 and has held a variety of management positions in the human resources department and PSE&G. She is a member of the Society of Human Resource Management and the Human Resource Planning Society. Ms. Brina has been active in the United Way and the American Cancer Society, and is a 1993 TWIN honoree.	Ms. Brina holds an Associate of Arts degree in business from Union College where she graduated cum laude, and a Bachelor of Science degree in marketing from Rutgers University where she graduated magna cum laude.
Manoj S. Chouthai	Vice President – Information Technology and Chief Information Officer	PSEG Services Corporation	Manoj S. Chouthai was named vice president – information technology and chief information officer for PSEG Services Corporation, in December 2006. He retains his position as chief technology officer for PSEG, which he has held since 2003. As vice president - information technology and CIO, Mr. Chouthai is responsible for setting the IT strategy for the company, developing and executing the IT business model, optimizing the costs and value of IT products and services, leading IT Governance and introducing new and emerging technologies into the enterprise. With over twenty years of management and leadership experience, Mr. Chouthai has a broad technology background and has a track record of successfully managing complex virtual organizations through periods of organizational transformation and change. Mr. Chouthai previously served as vice president in the information technology group at Prudential Financial. Prior to that, he provided thought leadership, developed technology roadmaps, created global sourcing strategies, managed strategic alliances, and implemented governance models within several leading insurance companies and investment banks.	Mr. Chouthai received a Master of Science degree in information systems from the Graduate School of Arts and Science at New York University (NYU), and a Master of Business Administration degree from the Stern School of Business at NYU.
Christine M. De Stefano	Vice President – Compensation and Benefits	PSEG Services Corporation	Christine M. De Stefano was named vice president – compensation and benefits of PSEG Services Corporation, in May 2009. She oversees the design and implementation of the benefits and compensation programs for PSEG's employees and retirees. Prior to joining PSEG Ms. De Stefano held the same position at Alpharma Inc., a pharmaceutical firm located in Bridgewater, New Jersey, where she worked since 2003. In addition to her experience at Alpharma, Ms. De Stefano has worked in benefits at Reed Elsevier Inc., was a consultant with Towers Perrin and held various finance and benefits management positions with J.P. Morgan & Co. Inc.	Ms. De Stefano has a Master of Business Administration degree in finance from Fordham University, Graduate School of Business Administration, and a Bachelor of Business Administration degree in finance from Pace University, The Lubin School of Business. She is a member of the Beta Gamma Sigma honor society.
Patricia R. McLaughlin	Vice President – Business Operations	PSEG Services Corporation	Patricia R. McLaughlin was named vice president - business operations of PSEG Services Corporation, in December 2006. She leverages over 20 years of accounting and utility industry experience. Ms. McLaughlin had been director - commercial operations group since 2001, and was a leader in the development of PSEG's Services Corporation - directing the organization responsible for the business model of the company. She had also been the director of various PSEG accounting functions, including management reporting, accounting and external reporting to the SEC, FERC and New Jersey Board of Public Utilities. Ms. McLaughlin was a leader at PSEG in setting cost allocation policy and philosophy. She joined PSE&G as director - corporate accounting in 1996. Prior to joining PSEG Ms. McLaughlin held several positions with Northeast Utilities' accounting department and the audit staff of Arthur Andersen and Company.	Ms. McLaughlin graduated from Marietta College with a Bachelor of Science degree in accounting and became a certified public accountant in the State of Connecticut. She also earned a Masters of Business Administration degree with a finance concentration from the University of Connecticut.

Name of Officer	Title	Organization	Experience	Education
Michael S. Paszynsky	Vice President – Security and Claims	PSEG Services Corporation	Michael S. Paszynsky was named vice president – security and claims of PSEG Services Corporation, in December 2006. Prior to this appointment he was director - corporate security at PSEG. As director, Mr. Paszynsky was the chief security officer responsible for developing and operationalizing PSEG's Enterprise-wide security, crisis management, and business continuity strategies, plans and policies. He began his career at PSEG in 2002, after having spent 25 years with AT&T – the last 6 of which were as its director - corporate security and claims. Prior to AT&T Mr. Paszynsky was a resident special agent for the American Express Company, a special agent with the New Jersey State Commission of Investigation, and an investigator with the New York State Special Prosecutor's Office. He also spent over 20 years in the United States Army Reserve – starting in a medical capacity and retiring from the Criminal Investigation Division. Mr. Paszynsky has served as a member of the board of directors of ISMA (International Security Management Association), a founding member of the Conference Board's Business Continuity and Crisis Management Council, a member of: the American Society for Industrial Security, the Association of Certified Fraud Examiners, the International Association of Chiefs of Police, the Edison Electric Institute, the American Gas Association, and an operations council member of the NJ Business Force – Business Executives for National Security.	Mr. Paszynsky has a Bachelor of Science degree in criminal justice as well as two professional certifications - "CPP" Certified Protection Professional (by exam) and "CFE" Certified Fraud Examiner. He is a graduate of the United States Army Military Police Academy and the United States Army's Medical Department Center & School. Mr. Paszynsky has completed executive education programs at the University of Virginia's Darden School of Business, Georgetown University, and Northwestern University's Kellogg School of (Business) Management.
Eric B. Svenson, Jr.	Vice President -- Environment, Health and Safety	PSEG Services Corporation	Eric B. Svenson, Jr. was named vice president – environment, health and safety (EHS) of PSEG Services Corporation, in December 2006. He is responsible for developing and administering EHS policy at PSEG; assuring compliance with all applicable local, state, and federal EHS laws and regulations; obtaining all necessary environmental licenses and permits for new and existing facility operations; performing environmental remediation on former manufactured gas plant sites and other legacy operations; and providing industrial safety support services to the businesses of PSEG. He had been director - corporate issues management, where he was responsible for directing PSEG's Washington lobbying activities to advance and protect PSEG's business interests before the United States Congress and federal regulatory agencies. Mr. Svenson has been with PSEG since 1973, holding positions in electric power production, business development, and environmental and governmental affairs. Prior, he served as director - plant support for PSEG Power, the merchant generation business of PSEG. He was responsible for developing strategies to optimize the performance of PSEG Power's fossil electric generation portfolio of 6,000 megawatts in New Jersey and New York. Mr. Svenson also developed the first phase of a plant maintenance optimization program, using reliability centered maintenance techniques to reduce expenditures. He joined PSEG in 1973 working in electric generation operations. Mr. Svenson has provided testimony at numerous New Jersey, Northeast, and national legislative and regulatory forums on electric industry restructuring and environmental matters. He also has co-authored with the Natural Resources Defense Council, several reports benchmarking electric power industry	Mr. Svenson graduated with honors from the Stevens Institute of Technology with a Bachelor of Engineering degree, and earned his master's degree in engineering from Stevens Institute. He is also a licensed New Jersey Professional Engineer.
J A. Bouknight, Jr.	Executive Vice President - Law	PSEG Services Corporation	J.A. "Lon" Bouknight, Jr. was named as executive vice president-law, in November 2009. In this position, he has general supervisory responsibilities for the law department and the office of the corporate secretary. Bouknight had been a partner in the Washington law office of Steptoe & Johnson, where he has served as a member of the regulatory and industry affairs department and as former chairman of the firm. His practice focuses on the electric power industry and on antitrust and competition issues in both regulated and unregulated industries. From 2005 to 2008, Bouknight served as executive vice president and general counsel of Edison International, a major electric company based in California. A graduate of Duke University School of Law, he has authored a number of articles and lectured extensively on energy industry and competition topics.	Mr. Bouknight graduated from Wofford College with a Bachelor's of Art in History and from Duke University with his jurisdoctorate.

Note1: Information not avaiable in discovery.
Source: Response to OC-95 and www.pseg.com

7. RISK MANAGEMENT

This chapter will discuss the Risk Management function of PSEG. It will include a description of the roles and functions of each group that takes part in the Risk Management process as well as an analysis of systems and methodologies used by PSEG to carry out the Risk Management function.

Summary of Findings

1. The Risk Management Committee is responsible for setting the level of risk that the company is willing to accept. The RMC is governed by a charter.

2. The Enterprise Risk Management Department ("ERMD") is responsible for identifying areas within the organization where risks are created and putting in place processes to assure that these risks are regularly measured on a consistent basis.

3. The ERMD uses Value-at-Risk methodology to aggregate and quantify the various risks facing the company.

4. ERMD has developed an internal rating system to measure the credit worthiness of PSEG counterparties. This rating system analyzes the counterparty's audited financial statements to determine the counterparty's credit standing. The department also observes a counterparty's credit default swaps and recent news to help determine credit standing.

5. ERMD uses the information system CCRM to maintain information on PSEG's counterparty credit.

6. PriceWaterhouseCoopers reviewed the Risk Management function at PSEG in 2008 and made four key recommendations. The recommendations were implemented by PSEG following the end of the review.

The Risk Management Committee (RMC) of PSEG is responsible for managing the company's exposure to commodity, credit, foreign exchange, interest rate and other financial risks.[1]

The committee is chaired by the Executive Vice President and Chief Financial Officer of PSEG and includes the Presidents of PSEG Power, PSE&G, PSEG Energy Holdings, and PSEG Energy Resources and Trade; the Executive Vice President and General Counsel of PSEG; Vice President and Controller of PSEG; Treasurer of PSEG; and the Chief Risk Officer of PSEG. The Risk Management Committee reports directly to the Audit Committee and Finance Committee of the PSEG Board of Directors.[2]

The Risk Management Committee is responsible for setting the level of risk that the company is willing to accept. It also recommends the daily and weekly Value at Risk limits to the PSEG Board of Directors,

[1] Response to Discovery, OC-334.
[2] Ibid.

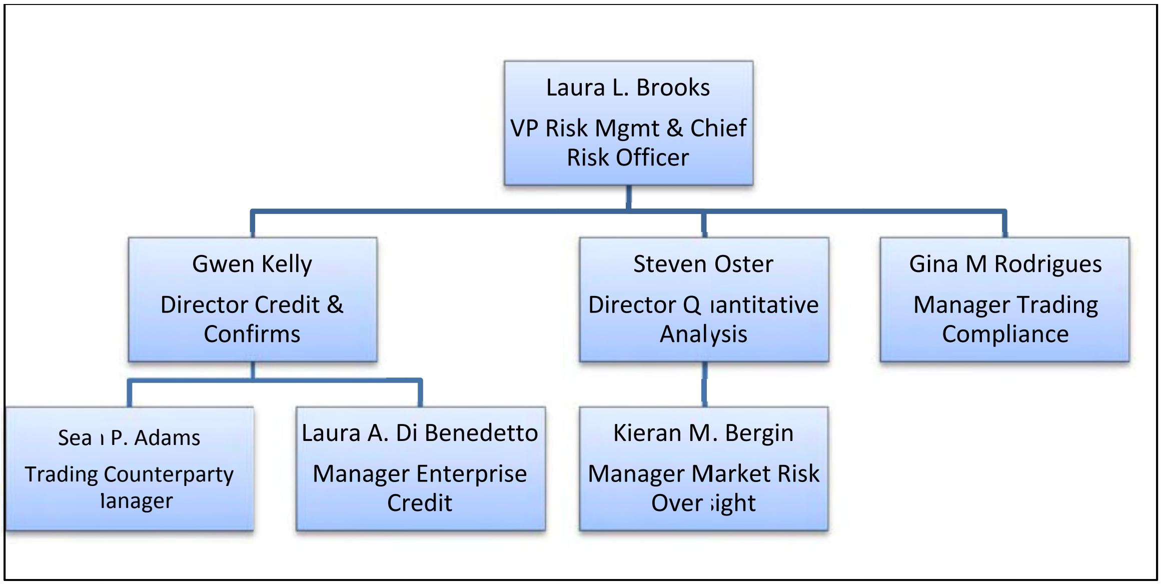
examines credit exposures for vendors, and does an annual review of the risk management policy and practice.[3] The RMC is mandated by its charter to meet at least ten times per year.[4]

The Enterprise Risk Management Department (ERMD) is responsible for identifying areas within the organization where risks are created and putting in place processes to assure that these risks are regularly measured on a consistent basis. This department is also responsible for developing, memorializing, and ensuring the application of consistent methodologies for valuing each class of risk exposure (i.e. commodity, interest rate, etc.) and subclass (i.e. gas, electric) of transactions. Furthermore, it is the department's responsibility to ensure that all transactions are valued accurately and that the prices, models, and methodologies used in valuation are adequately supported. The ERMD uses the Value-at-Risk methodology to aggregate and quantify the various risks facing the company. The Chief Risk Officer, during her interview, mentioned that PSEG uses an earnings at risk assessment with a three year outlook. PSEG calculates a trading and non-trading mark-to-market VaR, which is used in its SEC report.[5] The department prepares written reports for the Audit Committee, RMC, senior management and various other groups as necessary to provide relevant risk positions and to make recommendations to improve certain internal controls surrounding the risk process at PSEG.[6]

The Chief Risk Officer is the lead for the ERMD department and reports directly to the CFO of PSEG. The Chief Risk Officer is responsible for presentations, written and oral, on risk management and the actions of the RMC to the Audit Committee at its meetings and to the Board of Directors through the monthly ERMD report. The CRO is also responsible for the continuous education on risk matters for management and the Audit Committee.[7] Below is an organizational chart for the Enterprise Risk Management Department of PSEG.

[3] Interview with Laura Brooks, July 9, 2010.
[4] Response to Discovery OC-573 "RMC Report 12/15/09"
[5] Interview with Laura Brooks, July 9, 2010. Edited with an email from Mally Becker, 12/15/11.
[6] Response to Discovery, OC-334.
[7] Ibid

Table 7-1 – Risk Management Organization Chart



Source: OC-5 SUPPLEMENTAL 2

Within the ERMD, there is a centralized credit function that manages PSEG's credit risk exposure, monitors ongoing counterparty creditworthiness, reviews concentration of credit risks, and recommends credit risk reduction arrangements.[8]

As mentioned above, PSEG uses the Value-at-Risk methodology to assess and maintain the appropriate levels of risk. PSEG uses the variance/covariance VaR model to determine the potential loss of their commodity portfolio over a specified period of time.[9] The specified period of time for the trading and non-trading MTM activities are one-day holding period models with a 95% confidence level, and the portfolio VaR, which consists of owned generation, electric load-serving contracts, fuel supply contracts, and energy derivatives, which have a five-day holding period model with a 95% confidence level.[10]

[Begin Confidential]

[8] Response to Discovery, OC-334.
[9] http://pages.stern.nyu.edu/~adamodar/pdfiles/papers/VAR.pdf,
[10] PSEG 2009 10-K.
[11] Response to Discovery, OC-344.

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[14] **[End Confidential]**

PSEG also closely monitors their credit risk. The Company uses the term "Current Net Credit Exposure" to refer to the risk that represents the cash value of "in the money" positions that would be owed to PSEG if the contract between PSEG and its counterparty were terminated. The Company monitors the current net credit exposure in two ways: ensuring that it is within an acceptable range and by using an internal rating system that grades its counterparties based on their S&P credit rating.

The Current Net Credit Exposure is made up of three components: basic generation service (BGS), basic gas supply service (BGSS), and energy resources & trade (ER&T).[15] In the interview with Laura Brooks, Chief Risk Officer, she mentioned that PSEG expects that the impact of a credit downgrade would be the requirement for an additional $1 - $2 billion of collateral.[16] As of December 30th, 2009, PSEG's Current Net Credit Exposure was $1.125 billion. The utility represented $480 million of the total.[17]

The PSEG Risk Management department has evolved over the past five years or so from a financial risk management focus to a more broad "enterprise" risk management focus.[18] As described by the company it is "an expansion of PSEG-wide focus encompassing formalization, enhancement, and coordination of existing processes through a joint effort of various organizations across PSEG".[19] This diverse focus can be observed through some of the risk management services that the ERMD performs for the utility. Not only does the ERMD assist the utility in managing its credit exposure to counterparties, but the ERMD also does various risk-related tasks involving utility contracts, and reviews the BGSS process as well as the utility's hedging policy. The ERMD also helps the utility to build forecasting models to help them understand customer migration.[20]

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[12] Response to Discovery, OC-103.
[13] Response to Discovery, OC-344.
[14] Ibid.
[15] Response to Discovery, OC-103.
[16] Interview with Laura Brooks, July 9, 2010.
[17] Response to Discovery, OC-103.
[18] Interview with Laura Brooks, July 9, 2010.
[19] Response to Discovery, OC-1051.
[20] Interview with Laura Brooks, July 9, 2010.

In helping PSEG manage its credit exposure, the ERMD uses a wide array of market data to identify counterparty credit standing.[21] The ERMD monitors the external credit ratings for PSEG's counterparties. However, the department has also developed an internal rating system that analyzes information using the counterparty's audited financial statements. Other methods that the ERMD uses to monitor the credit of PSEG's counterparties include observing counterparties' credit default swap and monitoring the news.[22]

ERMD uses a customized information system to keep information on PSEG's counterparty credit. The system is called CCRM. CCRM is a 3rd party credit/collateral management tool that was specifically designed for PSEG, but it is now used by other energy companies. CCRM is connected to the PSEG trading system called ZaiNet where it obtains information utilized in setting credit limits. This information includes counterparty credit limits, exposure, collateral, security enhancements and contract information.[23] Most of the other ERMD functions are maintained in various Excel spreadsheets.[24]

The ERMD consists of 19 employees at the time of the interview with Laura Brooks, CRO, with the expectation of decreasing to 18 employees in the next year. Prior to June 2009, the Internal Controls group responsible for project managing SOX compliance was transferred to Internal Audit from ERMD in order to capitalize on organizational efficiencies with the Internal Audit group.[25] The transfer of the SOX compliance group to Internal controls reduced the number of employees in ERMD by four, to its current level.

The Risk Management function at PSEG was reviewed by PriceWaterhouseCoopers in 2008. PWC generally found that the risk management practices and infrastructure at PSEG was consistent with their industry peers. However, PWC did make the following recommendations (PSEG actions/responses follow the recommendations in parentheses):

- Staffing for the Quantitative Analysis group should be reviewed and the Director of Quantitative Analysis should consider hiring a PhD level lead quantitative resource with energy commodity experience. (PSEG hired a Senior Quantitative Analyst in January 2009 who holds a Ph.D. in Finance and Econometrics. The new hire also worked in the energy and banking industries in 1998.)[26]

- Document the relationships between the Risk Management Committee, Power Risk Council and ER&T Risk Advisory Committee and their related policy and practice documents. (PSEG combined these bodies into a single Risk Management Committee with a new and revised charter.)

[21] Response to Discovery, OC-140.
[22] Interview with Laura Brooks, July 9, 2010.
[23] Response to Discovery, OC-1294.
[24] Ibid.
[25] Response to Discovery, OC-1050.
[26] Response to Discovery, OC-1295.

- PSEG should consider moving the ER&T middle and back office functions whose tasks include contract administration and settlement to an independent function such as a controller group. (PSEG moved the settlements group from ER&T to the Accounting Services Department of the Services Company.)

- Distinguish the roles in the ER&T's Compliance and Controls group of the compliance advisor from the independent compliance monitor. (PSEG has separated the compliance and control functions by moving the compliance function to the ERMD and keeping the advisory function in the ER&T business unit.)[27]

Performance Assessment

The Risk Management function uses the balanced scorecard to measure its performance. Below is a table comparing the division's performance in 2009 to the previous year as well as the targets for 2009.

Table 7-2 – Risk Management Balanced Scorecard

PSEG Risk Management Balanced Scorecard			
Metrics	**2009 Benchmark**	**2008**	**2009**
People			
OSHA Recordable Incident Rate	0	0	0
OSHA Days Away Rate	0	0	0
Employee Development - MAST	92	100	99
Enhancement of Corporate Culture for Ethics and Compliance	70	69	82
Safe, Reliable			
SOX Test Failures - PSEG	31	28	26
SOX Test Failures - ERM	3	0	2
Control Deficiencies	10	N/A	8
Credit Customer Satisfaction	6.5	N/A	6.7
Economic			
Cost Effective SOX compliance processes (hrs)	29,600	31,147	27,928
Controllable O&M Cost ($M)	5.9	5.1	5.147
% of Corporate Planning Spend Benchmarked	50	N/A	14
Green			
Dow Jones Sustainability Index	60	N/A	74
Source: Response to Discovery, OC-999 and OC-1194			

As shown in the table above, the Risk Management department met or exceeded the 2009 target for each metric except for one, Percent of Corporate Planning Spend Benchmarked.

One of the most noteworthy metrics is Credit Customer Satisfaction. To obtain the Credit Customer Satisfaction metric, the Risk Management Department sends out a client satisfaction survey that is

[27] Response to Discovery, OC-589.

based on a seven point scale. The survey is intended to solicit from the Risk Management client an assessment of the products and services provided by the ERMD.

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8. STRATEGIC PLANNING

Introduction and Framework for the Strategic Planning Process

As stated in the most recent PSEG Strategy presentation given by Ralph Izzo, CEO, "PSEG Strategy and 2010-2014 Outlook", it is stated that PSEG's strategy is to "grow an operationally excellent, integrated generation, transmission and distribution business in competitive and/or carbon-constrained domestic markets".[1]

Strategic planning fundamentally involves the following process:

- Development of a plan or vision for the long-term direction of the Company.
- Identification of objectives that can be used to measure performance.
- Development of an implementation plan.
- Evaluation of performance and adoption of adjustments as needed by changed circumstances and actual events.

Corporate objectives should be aspirational in order to incent management to perform at its full potential and deliver the best possible results. Objectives relevant to PSEG would include:

- Growth in earnings per share and dividends
- Return on invested capital
- Strong bond ratings
- Increases in shareholder value measured against peers
- High customer satisfaction; customer service
- Enhancement of corporate image

The achievement of strategic objectives is a key element or indication of the likelihood of future financial performance. Therefore, it is important to employ both financial and strategic objectives in employing a balanced scorecard to measure corporate performance. Ultimately, the strategic plan must produce performance goals and result in the Company being in a favorable position relative to its peers. Absent such results, the validity of the plan and/or its execution must be considered.

Strategic planning is an ongoing and continuous process. A strategic plan must be modified when external conditions warrant reevaluation. The plan must constantly be evaluated against industry and competitive conditions.

[1] Response to Discovery, OC-4 SUPPLEMENTAL.

The Board of Directors has an important role in evaluating the strategic planning process. In its oversight function in this area, the Board should:

- Evaluate the effectiveness and performance of the strategic and business plans;
- Review the performance of the CEO and senior management in delivery of key objectives; and
- Tie senior management compensation to results that benefit shareholders and customers.

Summary of Findings

1. In 2008 and 2009, the Strategic Planning function reported to both the CFO and the EVP of Strategy and Development. Beginning in 2010, Strategic Planning only reported to the EVP of Strategy and Development.

2. In early 2010, the employee managing the corporate-level planning process changed titles from VP – Corporate Planning to VP – Corporate Strategy as the responsibility for the financial and budgeting group was moved from Corporate Planning to the CFO group.

3. Through 2009, the Executive Officer Group met four times each year at an offsite location to review and discuss key strategic issues.

4. While the utility industry has been fairly active in mergers and acquisitions, PSEG has placed more importance on acquiring assets, specifically generating assets, rather than companies.

5. PSEG uses the SWOT (strengths, weaknesses, opportunities, and threats) analysis in its strategic planning to create their business objectives for the next fiscal year.

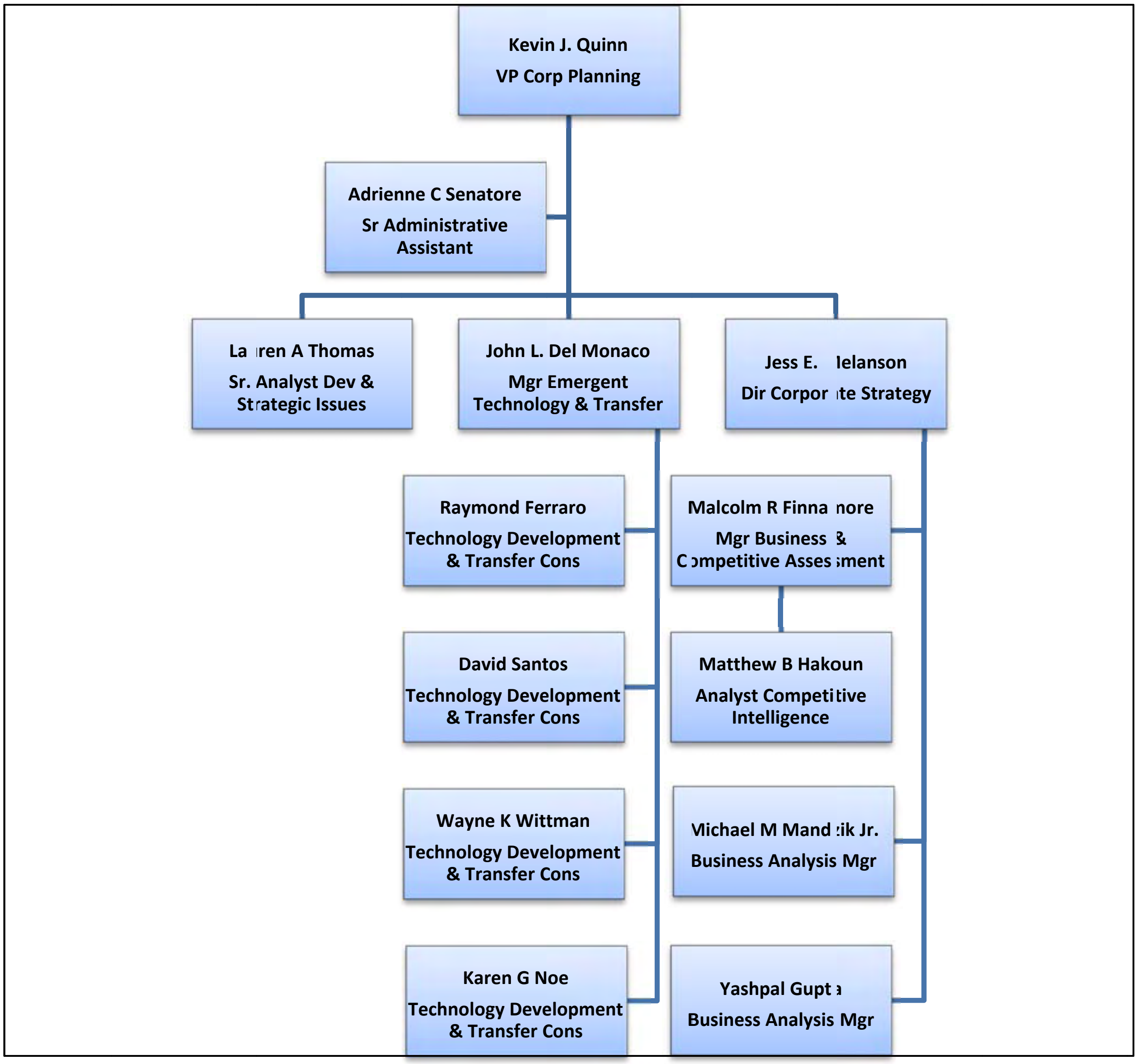
Overview of the Strategic Planning Process at PSEG

PSEG employs a centrally coordinated strategic planning process in which the three operating companies (PSE&G, PSEG Power, and PSEG Energy Holdings) engage in strategic planning and coordinate their efforts with the corporate-level process.

The corporate-level planning process is managed by the Corporate Planning department (in the PSEG Services Company). Strategic planning is the responsibility of Kevin Quinn, VP – Corporate Strategy who reports directly to Randall Mehrberg, EVP- Strategy & Development. Randall Mehrberg reports directly to Ralph Izzo, Chairman of the Board, President and CEO. Both are employees of the PSEG Services Corporation.[2] The organizational chart for the strategic planning function is shown below.[3]

[2] Response to Discovery, OC-96.
[3] Response to Discovery, OC-104.

Table 8-1 – Strategic Planning Organizational Chart



The Strategic Planning group has undergone some changes in early 2010. Up through January 1, 2010, Kevin Quinn had a dual reporting relationship that began in 2008. He reported to Caroline Dorsa, CFO and Randall Mehrberg, EVP Strategy & Development. PSEG changed Mr. Quinn's title from VP – Corporate Planning to his current title, VP Corporate Strategy, in early 2010. The change was primarily due to the financial and budgeting group moving from under his direction to the Valuation and Planning group that is led by Caroline Dorsa, CFO. The financial and budgeting group consisted of 10-12 people.[4]

The strategic planning function is separated into two main components: corporate strategy, emerging technologies and technology transfer. Corporate strategy is responsible for leading any strategic studies done by PSEG. The group is also responsible for pulling together information that goes into the five year

[4] Interview with Kevin Quinn, August 4, 2010.

business plan that is presented to the Board of Directors. The group also prepares the offsite Board of Director's minutes. Half of this group's time is spent on utility issues and the other half is spent on corporate or PSEG Power issues. The Emerging Technologies and Transfer group works primarily with the utility on near-term system monitoring. This ET&T group also follows longer-term technology developments relating to topics such as battery usage and storage and smart grid development. The majority of the ET&T group's time is spent on utility matters as this group was once a part of the utility's business group.[5]

Performance Assessment

The Corporate Planning division uses the balanced scorecard to measure its performance. Below is a table comparing the division's performance in 2009 to the previous year as well as the targets for 2009.

Table 8-2 – Corporate Planning Balanced Scorecard

PSEG Corporate Planning Balanced Scorecard			
Metrics	**2009 Benchmark**	**2008**	**2009**
People			
OSHA Recordable Incident Rate	0	0	0
OSHA Days Away Rate	0	0	0
Employee Development - MAST	92	68	99
Succession Planning	79	N/A	100
Safe, Reliable			
Strategic Issues Management	1	N/A	0.5
Planning Process Effectiveness	1	N/A	0.9
Vision Communication Plan	75	N/A	90.3
Economic			
Capital Project Results	89.8	98.3	91.1
Current Capital Performance	1	N/A	1.08
Controllable O&M Cost ($M)	5.6	N/A	5.1
Technology Transfer: # of active projects expected to provide > 50K in value if successful	10	N/A	12
% of Corporate Planning Spend Benchmarked	51	N/A	70
Green			
Emerging Technology: # of emerging/disruptive technology evaluations completed	2	N/A	2
Support to Develop Renewables Business	1	N/A	1.4

Source: Response to Discovery, OC-999 and OC-1194

As evidenced above, the Strategic Planning division has incorporated many new metrics to measure its performance. One of the new measurements for 2009 is succession planning. The measurement of 100 in 2009 means that succession plans were created and in place for all officer and other identified critical

[5] Ibid.

positions.[6] PSEG surpassed both the industry benchmark (64% per the Saratoga Institute) and its 2009 target.

The Planning group also has a couple of metrics that correspond with the performance of capital projects. The first metric, Capital Project Results, focuses on how well a capital project performed in the areas of cost, schedule, and benefits when it was initially presented for funding as well as how the project was carried out. Based on the weighted index used to measure the capital projects' performance, PSEG has improved the percentage from 52% in 2007 to 91% in 2009.[7] The second metric measures current capital performance. It is a new metric for 2009 and involves assessing the cost and schedule performance for all active capital projects for PSEG, PSE&G, PSEG Power, and PSEG Energy Holdings. The target for this metric was exceeded in 2009.

The Emerging Technology and Transfer group is responsible for a couple of metrics in the balanced scorecard also. They are responsible for the number of active projects transferred into business operations that provide a benefit greater than $50,000 based on a five-year NPV discounted at 15%. This group implemented 12 projects that met this criteria in 2009.[8] This group also had a target to present two studies and evaluations of emerging/disruptive technology to senior management in 2009. The group met the 2009 target by presenting evaluations on plug-in electric vehicles and large scale energy storage technologies.[9]

Communicating the Corporate Strategy

Communicating PSEG's strategic plan with executive management is a process that consists of four key offsite meetings of the Executive Officer Group (EOG) during which key strategic issues are reviewed. These meetings are supplemented with periodic updates and reviews at the EOG weekly meetings.[10]

The four key offsite meetings take place throughout the year. The spring meeting involves a Review of major industry trends, legislative policy and other broad topics which will influence the company's performance in the coming years. The mid-summer meetings consists of a review of key business assumptions and strategy revisions (if necessary) for the Operating Companies and the Services Company), along with an initial view of the potential financial performance in the coming five-year horizon. The early fall meeting addresses the review of business strategies, objectives and initiatives. Finally, the late fall meeting finalizes PSEG's strategic plan. Materials for these meetings are developed by Corporate Planning, the finance and planning staffs in the operating companies,

[6] Response to Discovery, OC-1194.
[7] Response to Discovery, OC-1194.
[8] Response to Discovery, OC-1496.
[9] Response to Discovery, OC-1497.
[10] Response to Discovery, OC-96.

and other groups within the company. At times outside consultants are invited to give additional perspectives.[11]

The strategic planning process also includes at least three interactions with the PSEG Board of Directors:

- Strategic Business Review: this a review of business issues and strategic options and opportunities that is typically conducted in early summer;
- Strategy Update/Plan Outlook: this is where the Strategic Planning Group discusses business strategies and the preliminary financial forecast with the Board of Directors; and
- Business Plan Review: this is the final review of the business strategies, objectives, and plans for the upcoming fiscal year that takes place in December. [12]

In 2009, the company's strategy, as communicated to its employees, centered on the company's vision, 2009 strategic objectives, and business results. PSEG takes advantage of several avenues through which to communicate their vision and strategy. There are face-to-face meetings where the CEO and other senior leadership are involved with sharing the company's vision and strategy to other executives and lower level employees on a scheduled basis. The vision and strategy are shared through print media as well. PSEG has a monthly company newspaper, which contains numerous articles relating to the company's vision and strategy. PSEG also uses electronic media outlets such as: the PSEG intranet site, PSEG's electronic newsletter published in Outlook, and computer screen savers with vision based messages.[13]

During the period of this audit, the Corporate Planning department was involved in various initiatives. These are outlined by entity below.[14]

- PSE&G
    - Electric and Gas Distribution Rate Case
    - PSE&G Solar Loan Program
    - PSE&G Solar-4-All
    - PSE&G Transmission Projects
- PSEG Power
    - Installation of Back-end Technology at PSEG Power's Hudson and Mercer
    - Nuclear Power Uprates
    - Nuclear License Renewal
    - New Nuclear Development
    - Peakers – CT
    - Peakers – NJ

[11] Ibid.
[12] Response to Discovery, OC-96.
[13] Response to Discovery, OC-105.
[14] Response to Discovery, OC-97.

- PSEG Energy Holdings
    - Compressed Air Energy Storage
    - Offshore Wind Development
    - Solar Business Development (PSEG Solar Source)

In addition, the Emerging Technologies and Transfer group has been involved in the following initiatives and projects over the last few years.[15]

- Electric and plug-in hybrid vehicles
- Battery storage
- Battery technology
- Solar driven desiccant cooling

Mergers & Acquisition Process

Utility mergers generally evolve to create a more cost-efficient operation and to expand geographic coverage. The industry activity in mergers and acquisitions over the last ten to fifteen years has been fairly robust. The principal underlying factors have included deregulation and industry restructuring. Significant foreign investment in US utilities has begun to occur in recent years. However, in his interview, Kevin Quinn noted that there are substantial regulatory hurdles to overcome when attempting to acquire regulatory assets. He cited that various regulatory issues played a significant role in preventing the merger between PSEG and Exelon from being successful.[16]

PSEG has a corporate development team that monitors the utility sector for potential opportunities and merger and acquisition activity. Opportunities, as well as current M&A activity in the sector, are periodically reviewed with the executive management of the company. In evaluating such opportunities, various factors are considered, including the strategic fit of an opportunity, the synergies created, its financial valuation, the financial impacts of the acquisition, sales growth rate, need for future investment, regulatory approval requirements, relative size and other factors.[17] Corporate governance requires the approval of the appropriate PSEG subsidiary boards and, if over a certain dollar threshold, the PSEG Board of Directors for authorization to enter into any binding agreements.[18]

Currently, PSEG is looking at opportunities to acquire assets, specifically generating assets, in place of acquiring companies. **[Begin Confidential]**

[End

[15] Interview with Kevin Quinn, August 4, 2010.
[16] Ibid.
[17] Ibid.
[18] Response to Discovery OC-107.
[19] Interview with Kevin Quinn, August 4, 2010.

Confidential] However, while there have been a number of utility M&A transactions in recent years in the East and Northeast, PSEG has chosen not to pursue such opportunities. It is Mr. Izzo's view that utility acquisitions are unlikely to create meaningful shareholder value, absent identifiable synergies that can be retained by shareholders.[20]

Strategic Planning Surrounding Federal and State Energy Policy

PSEG is committed to partake in the worldwide effort to combat the causes of climate change, more specifically, global warming by investing in energy efficiency, renewable energy, clean central station power, and taking a leadership position at the state and federal government level in advocating for strong climate change policies and legislation. PSEG invests in energy efficiency through various programs to help residential and commercial customers reduce their energy usage. Examples of these programs are the Carbon Abatement Program and the Energy Efficiency Economic Stimulus Program, which are mentioned in the Energy Efficiency section of this report. PSEG also invests in renewable energy to combat climate change through its various solar power programs and partnership in an offshore wind power project. The company is investing in clean central station power through the relicensing of its two nuclear facilities, Salem and Hope Creek as well as submitting an early site permit for a new nuclear facility. Finally, PSEG has taken a leading role with respect to promoting green jobs and green energy initiatives by affiliating itself with several different organizations and by actively influencing the state and federal governments.[21]

PSE&G Non-Utility Investments

PSE&G has set up a few subsidiary entities that are not related directly to the utility operations. These entities serve two primary purposes: economic development and financing. The amount invested in these non-utility investments total approximately $23 million. The net incomes for these investments are: ($1,044,000), ($579,000), and $754,000 for 2007, 2008, and 2009, respectively.[22]

The economic development entities are Public Service New Millennium Economic Development Fund LLC and PSEG Area Economic Development LLC. The former provided financial assistance by way of making funds available to loan to new or expanded economic development projects. The goal of this entity was to stimulate economic growth and create or retain employment opportunities. This fund has helped to finance 16 different projects with $30 million of PSE&G funding. Two of the projects remain to be completed and the funds returned to the entity.[23] PSEG Area Economic Development LLC provides the following services in New Jersey:

[20] Interview with Ralph Izzo, December 7, 2010.
[21] Response to Discovery, OC-136.
[22] Derived from Discovery, OC-137 (UPDATE).
[23] Response to Discovery, OC-306.

- Real estate site finding
- Listing and referral
- Corporate relocation
- Strategic land use and economic development planning

The company also has two subsidiaries: PSEG SiteFinders and PSEG Economic Development Services LLC.[24]

New Jersey Properties Inc. is a non-utility entity that acquires and maintains contaminated properties from PSE&G's former Manufactured Gas Plants. The entity acquired 35 properties from 1992-2004 for approximately $10 million. Later, four of these were disposed of in October 2008.[25]

There are also two non-utility entities set up for financing purposes. The Transition Funding I LLC and Transition Funding II LLC purchase bondable transition property, issue bonds collateralized by the bondable transition property, as well as collect a transition bond charge from PSE&G customers. All net proceeds from these funds are remitted to PSE&G as consideration for the property right in the transitional bond charge.[26]

PSEG Commitment to Non-Regulated Business Units

Like many other utility holding companies, PSEG has investments in generating assets and regulated utility transmission and distribution operations. Some utility holding companies have also diversified into business activities that presumably complement the core business model.

The following table provides a detail of the PSEG generation fleet.

[24] Ibid
[25] Ibid
[26] Ibid

Table 8-3 - Generation Po tfolio as of December 31, 2009

Public Service Enterprise Group Generation Portfolio as of December 31, 2009					
Type	Electric Generating Facility	Mission	Principal Fuels Used	Generating Capacity (MW)	Percentage of Portfolio
Coal-Fired					
	Hudson	Load Following	Coal	930	
	Mercer	Load Following	Coal	638	
	Keystone (A)	Base Load	Coal	391	
	Conemaugh (A)	Base Load	Coal	385	
	Bridgeport Harbor	Base Load/Load Following	Coal	526	
			Total Coal	2,870	18.5%
Gas-Fired					
	Sewaren	Load Following	Gas	453	
	Bergen	Load Following	Gas	1,178	
	Linden	Load Following	Gas	1,230	
	Bethlehem	Load Following	Gas	746	
	Guadalupe	Load Following	Gas	1,000	
	Odessa	Load Following	Gas	1,000	
	Essex	Peaking	Gas	617	
	Edison	Peaking	Gas	504	
	Kearny	Peaking	Gas	446	
	Linden	Peaking	Gas	336	
	Bergen	Peaking	Gas	21	
			Total Gas	7,531	48.4%
Nuclear					
	Hope Creek	Base Load	Nuclear	1,199	
	Salem 1 & 2	Base Load	Nuclear	1,346	
	Peach Bottom 2 & 3	Base Load	Nuclear	1,117	
			Total Nuclear	3,662	23.6%
Oil-Fired					
	New Haven Harbor	Load Following	Oil	448	
	Burlington	Peaking	Oil	553	
	Mercer	Peaking	Oil	115	
	Sewaren	Peaking	Oil	105	
	National Park	Peaking	Oil	21	
	Salem	Peaking	Oil	22	
	Bridgeport Harbor	Peaking	Oil	21	
			Total Oil	1,285	8.3%
Pumped Storage					
	Yards Creek (C)	Peaking	Pumped Storage	200	1.3%
			Total Electric Generation	**15,548**	**100.0%**

Source: Derived from December 31, 2009 10-K filing with the SEC.
(A) Operated by RRI Energy
(B) Operated by Exelon Generation
(C) Operated by JCP&L

PSEG has two major subsidiaries that represent a diversification into non-core market opportunities. The two PSEG affiliates that engage in these businesses are: [27]

- PSEG Energy Resources & Trade LLC (ER&T) – Provides risk management services and markets physical and financial energy and energy-related products throughout the greater Northeast region of the United States as well as Texas.
- PSEG Energy Holdings – The primary focus of this subsidiary is to manage the portfolio of international leveraged lease investments. This subsidiary also manages a few domestic generation investments, including solar and other renewable generation sources.

PSEG Strengths, Weaknesses, Opportunities, and Threats[28]

PSEG uses the SWOT (strengths, weaknesses, opportunities, and threats) analysis in its strategic planning. The following SWOT analysis summary comes from the PSEG Strategy and Outlook 2010-2014 presentation that was given by Ralph Izzo, CEO.

[Begin Confidential]

[27] Response to Discovery OC-1
[28] Response to Discovery OC-4 SUPPLEMENTAL

[29] Response to Discovery OC-4 SUPPLEMENTAL

o **[End Confidential]**

Essentially since the industry restructuring, PSEG has faced certain key business risks:

- Market Concentration in PJM
- Single state regulation
- Weak balance sheet
- Asset concentration

The company's financial metrics have improved over time, in part due to asset divestitures owned by PSEG Resources and PSEG Global. Otherwise, there has been little progress to address these risks through the pursuit of strategic alternatives.

[30] Ibid

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9. External Relations

This chapter focuses on the various groups that make up the External Relations Function. These groups include: state governmental affairs, federal affairs, policy and environment, health and safety and corporate social responsibility and sustainability. These groups often work together with the primary goal and responsibility of properly balancing the needs of PSEG and its shareholders with the policy objectives of legislators, regulators, and consumers.

Summary of Findings

1. The External Relations function changed its reporting relationship in early 2010 following an analysis conducted in 2009 recommending that PSEG integrate all functions that communicate and maintain relationships with external parties. This led to the External Relations function being placed under the Strategy and Development group.

2. Overland analyzed benchmark data from 2008 on the staffing of an External Relations function within a company. It was noted that PSEG staffs at least twice the professionals and administrative support staff in External Relations as the median for the group of companies found in the benchmark study.

3. Overland analyzed benchmark data from 2008 on the size of the budget for a company's External Relations function. We found that of the companies participating in the survey, only one in five companies had a higher External Relations budget than PSEG.

4. PSEG created the PSEG Foundation to provide programs and assistance to support the company's three priority areas of giving: education, environment, and community and economic development.

5. In each of the years from 2001 to 2008, the PSEG Foundation has made fewer contributions as a percentage of pre-tax income than other utility companies that participated in a Conference Board survey.

6. PSEG earned Edison Electric Institute's Edison Award for 2010 for bold and innovative growth strategy geared toward clean energy, energy efficiency, and job creation.

7. PSEG is a member of the Dow Jones Sustainability North America Index. The index is made up of companies that attain the highest 20 percent in measures of sustainability.

Recommendations

1. Overland observed that all of the metrics for the External Affairs function were met, except one in 2009. We recommend that PSEG review its External Relations metrics and incorporate stretch goals into their benchmarks in the balanced scorecards in the future.

2. PSEG should increase its annual level of contributions to the PSEG Foundation as it is consistently below the median amount of corporate foundation giving amongst its peers.

The External Relations function is comprised of four separate business units at PSEG: State Governmental Affairs, Federal Affairs, Policy and Environment, Health and Safety and Corporate Social Responsibility and Sustainability. These four units are led by Senior Vice President – Public Affairs & Sustainability, Anne E. Hoskins. Ms. Hoskins reports to the Executive Vice President – Strategy & Development and President of PSEG Holdings, Randall Mehrberg.[1]

The External Relations function has undergone a number of changes in the recent years. The External Relations function previously reported to R. Edwin Selover, EVP and General Counsel prior to his retirement in January 8, 2010 and Ms. Hoskins' promotion to senior vice president.[2] The change in reporting relationships to its current status was due to PSEG determining that External Relations was a better fit in its organizational structure under the Strategy and Development group. This determination was made following an analysis conducted in 2009 that suggested that PSEG should create an organization to integrate all of the external facing groups. The Company created the Public Affairs group for that purpose with the head of the group, the SVP – Public Affairs reporting to the EVP of Strategy and Development.[3] The External Relations group has grown from approximately 50 employees to about 60 employees during 2010.[4] The Environment, Health & Safety (EH&S) subgroup within External Relations has decreased from 61 employees in November 2009 to 19[5] as the employees performing permitting tasks for each operating company have been transferred from the Service Company to their respective operating company.[6]

Though the External Relations group has no employees dedicated solely to utility projects, the function spent a large amount of time and resources in 2009 focusing on large utility projects such as the Susquehanna-Roseland transmission line. In 2010, it anticipates that less time will be spent on utility issues.[7]

The goals of the business units mentioned above are as follows: [8]

- Protect and advance corporate and business units' objectives through federal and state legislation and administrative actions
- Develop, manage, and enhance relationships at the federal and state levels with key stakeholders to ensure successful advocacy
- Identify and flag threats and opportunities to PSEG from the legislative and the executive branches of the federal and state governments

[1] Based on Organizational Charts provided in preliminary meetings with PSEG. Updated via discussion (email) with Mally Becker, Corporate Rate Counsel, PSE&G.
[2] Interview with Anne Hoskins, SVP Public Affairs & Sustainability, August 2, 2010.
[3] Response to Discovery, OC-1160.
[4] Response to Discovery, OC-5 SUPPLEMENTAL 2 and interview with Anne Hoskins, SVP Public Affairs & Sustainability, August 2, 2010.
[5] Response to Discovery, OC-1159.
[6] Interview with Anne Hoskins, SVP Public Affairs & Sustainability, August 2, 2010.
[7] Ibid.
[8] Response to Discovery, OC-108 (UPDATE).

Performance Measurement

The goals mentioned above are pursued and tracked through the use of the balanced scorecard. There are several metrics in the External Relations balanced scorecards. The results of the 2008 and 2009 balanced scorecard are shown in the table below.

Table 9-1 – External Affairs Balanced Scorecard

External Affairs Balanced Scorecard 2009			
Metrics	2009 Benchmark	2008	2009
People			
OSHA Recordable Incident Rate	0	0	0
OSHA Days Away Rate	0	0	0
Employee Development - MAST (%)	92	92	95
Enhancement of Corporate Culture for Ethics and Compliance	73	66	82
Safe, Reliable			
Communication Plan - Vision	75	65	90.3
Corporate Social Responsibility	85	N/A	87.1
Economic			
Controllable O&M Costs ($M)	16.7	15	15.6
% of Spend Benchmarked	34.3	34.1	33.7
Green			
Critical Public Affairs Initiatives	15	13	15
Thought Leadership - Customer Perception	80	76.5	77.8
Thought Leadership - Elite Perception	48.5	44	71.5
Thought Leadership - Media	85	N/A	94
Thought Leadership - Public Policy	85	N/A	98
Source: Response to Discover OC-775			

As shown in the table above, the Public Affairs department met or exceeded the 2009 target for each metric except for one, Thought Leadership – Customer Perception.

Some of the more noteworthy metrics are described below.

- Corporate Social Responsibility (CSR) – In 2009, External Relations created a plan to “align corporate philanthropy with thought leadership and a commitment to improving the quality of life for [PSEG stakeholders]”.[9] The plan included initiatives such as:
    - Conducting seminars and workshops for nonprofit organizations to strengthen community relationships.
    - Develop communications on CSR initiatives in appropriate periodicals.
    - Increase the amount of employee donations of time and money through various PSEG giving programs.
    - Launch the Crisis Fund.[10]

  The goal for 2009 to complete 85% of the plan was met.
- Critical Public Affairs Initiatives – PSEG identified 20 policy, legislative or regulatory initiatives that it believed would have a significant impact on PSEG’s business objectives. Many of these initiatives deal with influencing legislation on the federal and state level. Others deal with

[9] Response to Discovery, OC-775
[10] Ibid.

obtaining support for various energy conservation programs and initiatives. The goal for 2009 to complete 75% of the initiatives was met.[11]

- Thought Leadership – PSEG has a leadership program that is aimed at affecting different groups of stakeholders. These groups are customers, elite (New Jersey-wide opinion elites), media and the community. PSEG has developed a different metric to measure the performance against each group with specific initiatives to be measured in the media and community outreach groups. PSEG met the target for the elite, media and community group in 2009. The company did not meet the target for the customer group in 2009.[12] In 2010, the initiatives listed to improve in this metric were to publicize PSE&G's Solar Loan and Solar 4 All Program as well as other corporate citizenship activities.[13]

PSEG's External Relations department also participates in a benchmarking study through the Public Affairs Council. The study includes 130 companies from various industries as well as 20 companies from the utility sector. Overall, the study found PSEG to have a very robust external relations (public affairs) group. This is demonstrated in more detail below:[14]

- Staffing
    - According to the study, PSEG employs 46 professionals and 10 administrative support staff for its public affairs group, while the median for the benchmark study was 17.5 and 5, respectively.
- Budget
    - According to the study, PSEG had a public affairs budget of $15 - $17.5 million, which placed them in the 80th percentile of utility sector. This means that only 20% of the utility companies in the study had a higher public affairs budget than PSE&G.
    - As a percentage of revenue, PSEG's 2008 public affairs budget ranged from 0.1126% to 0.1314% (based on 2008 revenue of $13.322B). This put PSE&G in the upper limit of the benchmarking results for this metric. The median level for this measurement ranged from 0.03% to 0.0617%, which means that PSE&G public affairs budget would be between $5M and $8M to achieve the median level of budgeted spending for its utility peer group.

State Governmental Affairs

State Governmental Affairs Mission Statement:
"The State Governmental Affairs (SGA) department provides political and legislative process expertise and organizes intelligence gathering and strategic relationship management on behalf of PSEG in pursuit of its business objectives in New Jersey and other key states. We contribute to the internal policy-making process by adding external audiences within state government and other key constituencies. Through its Corporate Responsibility functions, SGA supports Enterprise by aligning corporate philanthropy with thought leadership and a commitment to improving the quality of life for customers, employees and the communities we serve".

[11] Ibid
[12] Response to Discovery, OC-775.
[13] Response to Discovery, OC-1163.
[14] Response to Discovery, OC-57 "Comparative Analysis from the 2008 State of Corporate Public Affairs and the 2008 State Government Relations Benchmarking Report." *Public Affairs Council*

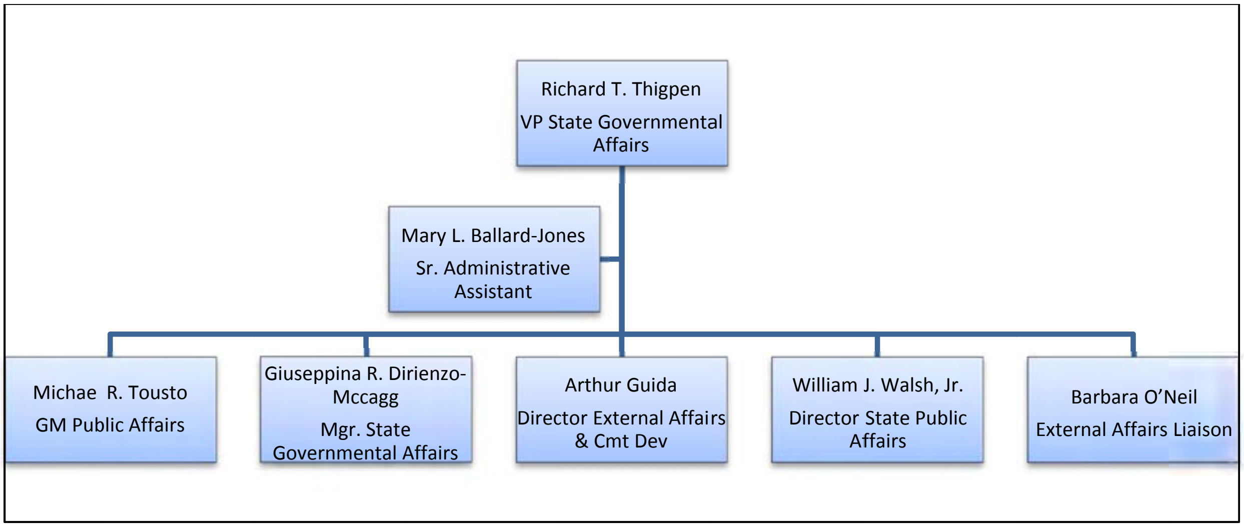
State Governmental Affairs Core Functions:

- Advocacy
  - Advocate for the protection/advancement of PSEG's business interests in the NJ state legislature and regulatory arenas.
  - Proactively monitor legislative and regulatory initiatives to identify opportunities and/or threats. Utilize departmental expertise of the political and legislative processes to influence positions and outcomes to PSEG's advantage.
- Corporate Responsibility
  - Promote strong corporate citizenship and philanthropy by making focused contributions to deserving organizations and institutions that align with PSEG's business objectives.
  - Centralized decision making and administration of corporate contributions, corporate sponsorships, employee volunteer programs, employee giving campaigns and event management.
- PSEG Foundation
  - Provide funding only to charitable 501(c) (3) organizations for support of programs and issues that are closely aligned with the objectives and goals of PSEG.
  - Provide a thoughtful, strategic, structured, well-defined contributions program annually to the PSEG Foundation Board that aligns with Company objectives and goals to enhance its internal and external image. A centralized source of accountability.
- Public Affairs & Policy Support
  - Represents the function of issue analysis in order assess the appropriate forums/individuals for education. It requires significant relationship management in order to facilitate external discussions.
  - Contribute to the internal policy-making process by adding strategic insight from the political and legislative process perspective. Communicate PSEG positions to the appropriate external audiences.

See State Governmental Affairs organizational chart below.[15]

[15] Response to Discovery, OC-108. Updated using OC-5 SUPPLEMENTAL 2 and interview with Richard Thigpen, VP State Governmental Affairs, August 2, 2010.

Table 9-2 – State Government Affairs Organizational Chart



Federal Affairs and Policy

Federal Affairs and Policy Mission Statement:
"The Federal Affairs and Policy Department provides policy and public affairs support on critical public policy issues that impact the corporation in Washington, D.C., New Jersey and other states important to PSEG. Federal Affairs and Policy positions PSEG as a thought leader on issues including climate change, workforce development and emerging technologies. Federal Affairs and Policy protects and advances PSEG's economic interest through advocacy and lobbying before Congress, Federal and State Agencies and Administrations".

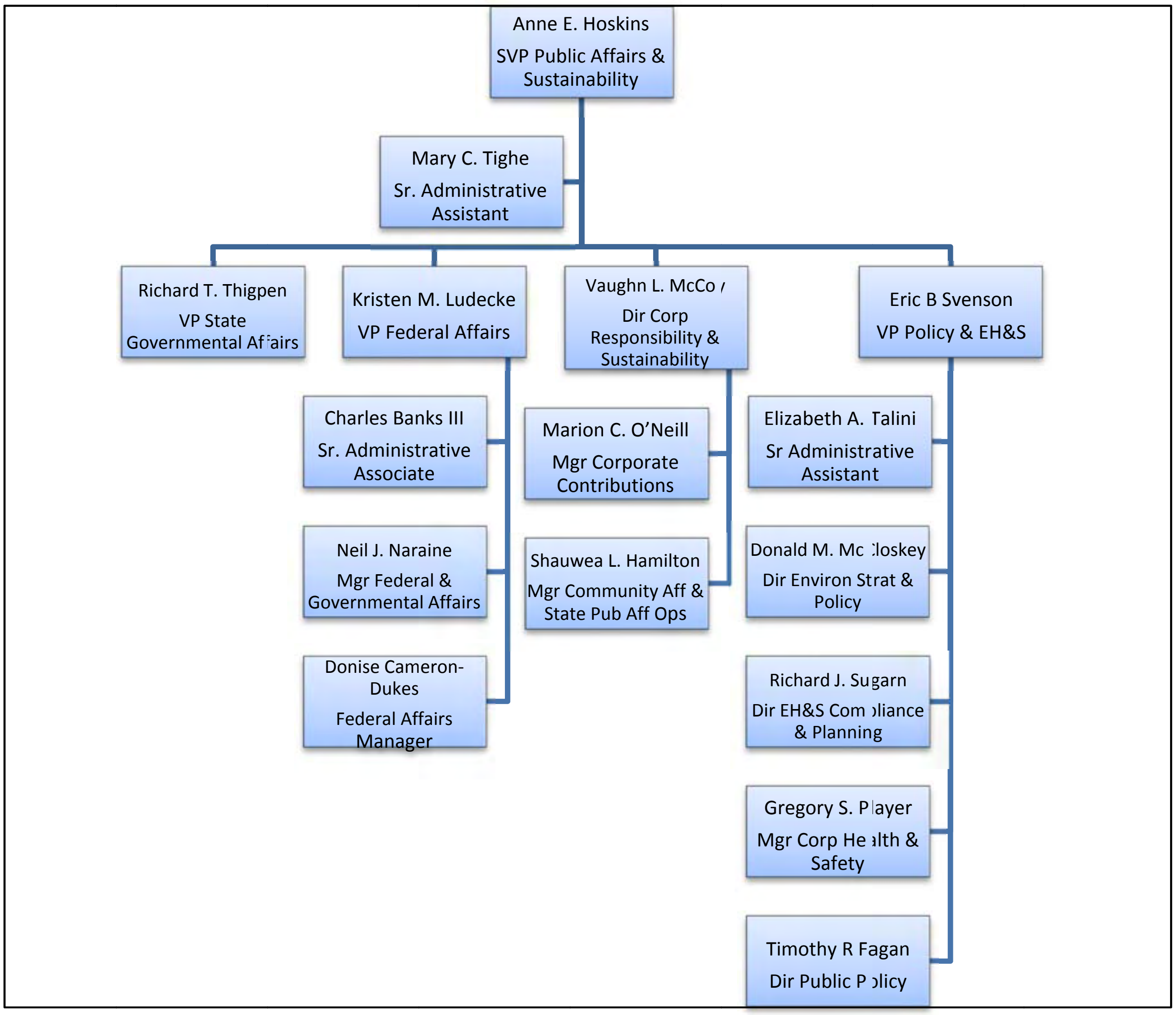
Federal Affairs and Policy Core Functions:

- Public Policy Development
  - Develop and coordinate public policy positions to support objectives of PSEG business units and to position PSEG as a thought leader on critical policy issues.
  - Provide clear and persuasive policy statements and advocacy documents. Resolve conflict in policy positions between different business units and develop common corporate positions.
- Congressional & Federal Relations
  - Advance and protect PSEG's short and long-term business interests in the federal legislative and regulatory arenas.
  - Identify and flag threats and opportunities to PSEG from the U.S. Congress and the Executive Branch; influence positions and policy outcomes to PSEG's advantage.

- State Relations Outside of New Jersey (Lobbying of Legislators & Executive Agencies)
  - Enhance PSEG business opportunities in jurisdictions outside of NJ.
  - Develop and implement public affairs and governmental affairs plans.
  - Lobby state governors, regulatory agencies, legislatures, municipal offices.
  - Coordinate political activity.

The Federal Organization Chart is shown below.[16]

Table 9-3 – Federal Organizational Chart



In addition to her role as the leader of the External Relations function, Anne Hoskins is also a member of the Executive Officer Group as the Chief Sustainability Officer. PSEG has placed a high emphasis on sustainability programs to the point of earning EEI's Edison Award for 2010 "in recognition of its bold

[16] Response to Discovery OC-108. Updated using OC-5 SUPPLEMENTAL 2 and interview with Anne Hoskins, SVP Public Affairs & Sustainability, August 2, 2010.

and innovative growth strategy geared toward clean energy, energy efficiency, and job creation".[17] The 2010 Sustainability Report highlights PSEG sustainability programs that center on "addressing climate change, upgrading aging infrastructure, and investing in workforce development".[18] PSEG is also a member of the Dow Jones Sustainability North America Index, which is composed of the top 20 percent of North American companies based on sustainability performance.[19]

PSEG has 25 employees (15 of which are registered lobbyists[20]) who meet with legislators and members of federal, state, or local government administrations or agencies to influence legislation and shape public policy on utility industry and PSEG matters.[21]

Current Legislative and Regulatory activities and challenges in New Jersey are:

- The State Senate and Assembly are beginning to address legislation necessary to
- implement the Energy Master Plan.
- PSE&G must begin to focus on compliance with the Energy Master Plan, including:
  - Transfer of Energy Efficiency programs back to PSE&G.
  - 20% reduction of energy sales.
  - 30% RPS in electricity by 2020.
  - 3,000 Mw of offshore wind by 2020.
- Permits and other issues regarding the Susquehanna-Roseland transmission line project.

Key Federal Issues now include:

- $787 billion Economic Stimulus Bill – significant funding is included for energy efficiency programs; upgrading the transmission network; and research in support of renewable and energy efficiency technologies.
- Climate change – House position is 20% reduction in GHG by 2020.
- Renewable Portfolio Standards – House position is currently in the 17.5% to 25% range; the Senate is currently at 15%, both to be targeted by 2020.
- Energy Efficiency Standards – Utilities may be mandated to reduce energy sales by annual targets or pay penalties.
- Dividend taxation rate – the administration position may propose to raise the 15% rate to 25% on incomes over $250,000.
- Difficult economy – high and fluctuating energy prices and low amounts of discretionary income make it difficult for people to pay a premium for cleaner energy.

Outside Lobbying

The following is a summary of outside lobbyist activities associated with PSEG and PSE&G.

[17] PSEG Press Release August 3, 2010 "PSEG Releases 2010 Sustainability Report".
[18] Ibid.
[19] Ibid.
[20] Response to Discovery, OC-405.
[21] Response to Discovery, OC-110.

Table 9-4 – State Government Affairs Consultants for PSEG and PSE&G

State Governmental Affairs Consultants				
	Lobbyist Firm	2007	2008	2009
1	Princeton Public Affairs Group	$ 93,044	$ 99,649	$ 84,000
2	1868 Public Affairs	$ 72,000	$ 60,000	$ 72,000
3	Public Strategies Impact, LLC	$ 60,000	$ 94,500	$ 92,108
4	The Marcus Group, Inc.	$ 30,263	$ 20,000	$ 25,000
5	MC2 Public Affairs Group, LLC	$ 60,719	$ 16,879	
6	Donald Sico & Co., LLC		$ 140,000	$ 120,000
7	Jack Collins Enterprises	$ 78,000	$ 66,000	$ 72,000
8	WolfBlock/Robert Byrd	$ 27,000	$ 27,000	$ 44,250
9	Issues Management, LLC			$ 3,000
	Total	$ 421,026	$ 524,028	$ 512,358

Source: Response to Discovery OC-109 (UPDATE).

Princeton Public Affairs Group: Statehouse lobbying and general public affairs support.

1868 Public Affairs: Public affairs support also provides back-office public relations support.

Public Strategies Impact, LLC: Statehouse lobbying and general public affairs support.

The Marcus Group, Inc.: Provide strategic community relations advice and counsel and communications services with emphasis on transmission issues.

MC2 Public Affairs Group, LCC: Public affairs consulting for utility related matters.

Donald Sico & Co. LLC: General public affairs support.

Jack Collins Enterprises: Public affairs support for PSEG Nuclear, South Jersey Focus.

WolfBlock/Robert Byrd: Public affairs support for PSEG Nuclear, Delaware Focus.

Issues Management: Public affairs support related to formula rates legislation.

Table 9-5 – Federal Affairs and Public Policy Consultants

Federal Affairs and Public Policy Consultants				
	Lobbyist Firm	2007	2008	2009
1	Edison Electric Institute	$ 270,942	$ 217,056	$ 211,643
2	American Gas Association	$ 9,309	$ 8,825	$ 20,115
3	American Benefits Council	$ 5,400	$ 6,120	$ 6,120
4	US Chamber of Commerce	$ 8,700		
5	Nuclear Energy Institute	$ 32,073	$ 33,288	$ 50,077
6	Electric Power Supply Association	$ 37,500	$ 37,500	$ 37,500
7	American Wind Energy Association		$ 405	$ 935
8	Alliance to Save Energy		$ 1,000	$ 750
9	Business Roundtable		$ 92,598	
10	Business Council for Sustainable Energy		$ 7,500	$ 17,500
11	Compete	$ 395,071	$ 608,326	$ 308,332
12	MJ Bradley	$ 100,000	$ 100,000	$ 100,000
13	Palmetto Group	$ 165,000	$ 165,000	$ 100,000
14	MWR Group	$ 60,000	$ 60,000	$ 50,000
15	Artemis	$ 60,904	$ 63,299	$ 43,150
16	GSI	$ 130,513	$ 130,695	$ 100,409
17	MWW	$ 60,361	$ 90,000	$ 15,131
18	Stunz Davis			$ 13,997
19	Tim Yehl			$ 60,000
	Total	$ 1,335,773	$ 1,621,612	$ 1,135,659

Source: Response to Discovery OC-109 (UPDATE).

Edison Electric Institute: Advocates on behalf of shareholder-owned electric company members before Congress, federal and state regulatory agencies, the courts, and various industry organizations.

American Gas Association: Provides advocacy on natural gas issues for natural gas pipeline and delivery companies before Congress, regulatory agencies and the courts.

American Benefits Council: Provides advocacy of employer-sponsored benefit programs in Washington, D.C.

US Chamber of Commerce: Provides public policy advocacy for major issues affecting the business community before Congress, regulatory agencies and courts.

Nuclear Energy Institute: Provides advocacy for nuclear energy and regulatory issues affecting the industry.

Electric Power Supply Association: Provides advocacy for the competitive power supply industry before Congress, regulatory agencies and courts.

American Wind Energy Association: Provides regulatory advocacy in wind power in the energy market.

Alliance to Save Energy: Provides support on energy efficiency and climate change legislation.

Business Roundtable: Provides direct research, develops position papers, recommends policy, and lobbies Congress and the administration on five main focus areas: Consumer health, corporate leadership, workforce development, sustainable growth and international engagement.

Business Council for Sustainable Energy: Advocates energy and environmental policies that promote markets for clean, efficient and sustainable energy products and services.

Compete: Provide advocacy for competitive electricity markets before Congress, FERC, and other regulatory agencies. Expenditures to this coalition, which was funded completely by PSEG Power, were the cause for most of the variance in 2008 and 2009. In 2009, it was determined that the expenditures weren't a necessity and the funding to the coalition dropped sharply.[22]

MJ Bradley: Provides analytical and policy development support for climate change issues.

Palmetto Group: Provide tax consulting services for various corporate and business specific tax issues.

MWR Group: Provides general consulting services on a variety of utility related issues including transmission and water.

Artemis: Provides general consulting services on a variety of issues including climate, 316b, health care, card check and stimulus money.

GSI: Provides general consulting services on a variety of utility related issues.

MWW: Provides consulting services for nuclear and utility ratemaking language in stimulus, climate change, transmission, marine spatial planning, etc.

Stunz Davis: Provides consulting services for utility rate making legislation.

Tim Yehl: Provides consulting services for nuclear and utility ratemaking language in stimulus, climate change, transmission, marine spatial planning, etc.

[22] Interview with Anne Hoskins, August 2, 2010.

Table 9-6 – Environmental Policy Consultants

	Environmental Policy Consultants			
	Lobbyist Firm	2007	2008	2009
1	MJ Bradley	$ 318,765	$ 264,095	$ 208,478
	Clean Energy Group	$ 51,500	$ 51,500	$ 51,500
	Clean Energy Group - Section 185 Initiative		$ 21,865	
	Regional Greenhouse Gas Coalition	$ 25,000	$ 25,000	
	CERES Emissions Benchmarking Report		$ 80,000	
2	Class of 85	$ 28,800	$ 30,000	$ 10,000
3	Utility Solid Waste Advisory Group	$ 51,000	$ 60,000	$ 60,000
4	Utility Water Act Group	$ 63,122	$ 82,766	$ 86,087
5	Center for Clean Air Policy - Dues	$ 37,500	$ 37,500	$ 37,500
6	Center for Clean Air Policy - Climate Policy Initiative		$ 25,000	
7	Center for Clean Air Policy - Board Membership			$ 35,000
8	Water Resources Association of the Delaware River Basin	$ 6,000	$ 6,000	$ 3,000
9	CHH Partners	$ 16,853	$ 3,033	
10	Business Council for Sustainable Energy		$ 15,000	$ 10,000
11	Environmental Energy Alliance of New York		$ 26,000	
12	Site Remediation Industry Network - New Jersey		$ 3,000	$ 3,000
	Total	$ 598,540	$ 730,759	$ 504,565

Source: Response to Discovery OC-109 (UPDATE).

MJ Bradley: Provides analytical and policy development support for climate change and Clean Air Act issues.

Clean Energy Group: Advocates energy and environmental policies/national climate and multi-pollutant legislation.

Regional Greenhouse Gas Coalition: Advocates for regional legislation that will regulate greenhouse gases in a consistent manner and defers to national legislation when enacted.

CERES Emissions Benchmarking Report: Reports on the air emissions of the electric generation industry over a two year period.

Class of 85: The Class of '85, a national group of approximately 30 electric generating companies, has actively participated in developing all the major air-related regulations affecting electric generators since the passage of the 1990 Clean Air Act Amendments.

Utility Solid Waste Advisory Group: USWAG's purpose is to participate on behalf of its members in EPA's rulemakings that focus on solid waste and hazardous materials management and related topics; and in litigation arising from those rulemakings.

Utility Water Act Group: UWAG's purpose is to participate on behalf of its members in EPA's rulemakings under the CWA and in litigation arising from those rulemakings.

Center for Clean Air Policy: A non-profit think tank, CCAP helps policy-makers around the world develop, promote and implement innovative, market-based solutions to major climate, air quality and energy problems that balance both environmental and economic interests.

Water Resources Association of the Delaware River Basin: WRADRB is a non-profit, non-partisan advocacy and public information organization whose stated mission is to promote sound water resources management within the Delaware River Basin.

CHH Partners: Provides advice and counsel on environmental issues affecting the energy and electric utility industry with emphasis on issues arising within the state of Pennsylvania.

Business Council for Sustainable Energy: Advocates energy and environmental policies that promote markets for clean, efficient and sustainable energy products and services.

Environmental Energy Alliance of New York: EEANY is an ad hoc, voluntary group of electric generating companies, transmission/distribution companies and other providers of energy services in the State of New York. The primary purpose of the Environmental Energy Alliance of New York (EEANY) is to support and enhance the efforts of its members, electric generating companies, electric and gas transmission/distribution companies and/or energy services companies, in understanding New York State environmental regulatory initiatives, in order to permit them to more effectively (1) formulate and achieve their business goals and (2) proactively advocate cost-effective environmental regulations and policies.

Site Remediation Industry Network: SRIN is a coalition of more than 30 companies and associations that address contemporary regulatory issues pertaining to the Site Remediation Program under NJDEP.

PSEG Foundation

The PSEG Foundation provides programs and assistance supporting PSEG's three priority areas of giving: education, environment and community and economic development.[23] The Chairman of the Board of the PSEG Foundation is Richard Thigpen and Vaughn McCoy is the President of the Foundation. There are seven members of the Foundation, all of which are PSEG employees. The Foundation is funded by a small reserve or temporary endowment that is normally two to three times the annual giving level.[24]

Below is a table showing the amounts PSEG has contributed to its Foundation since 2001.

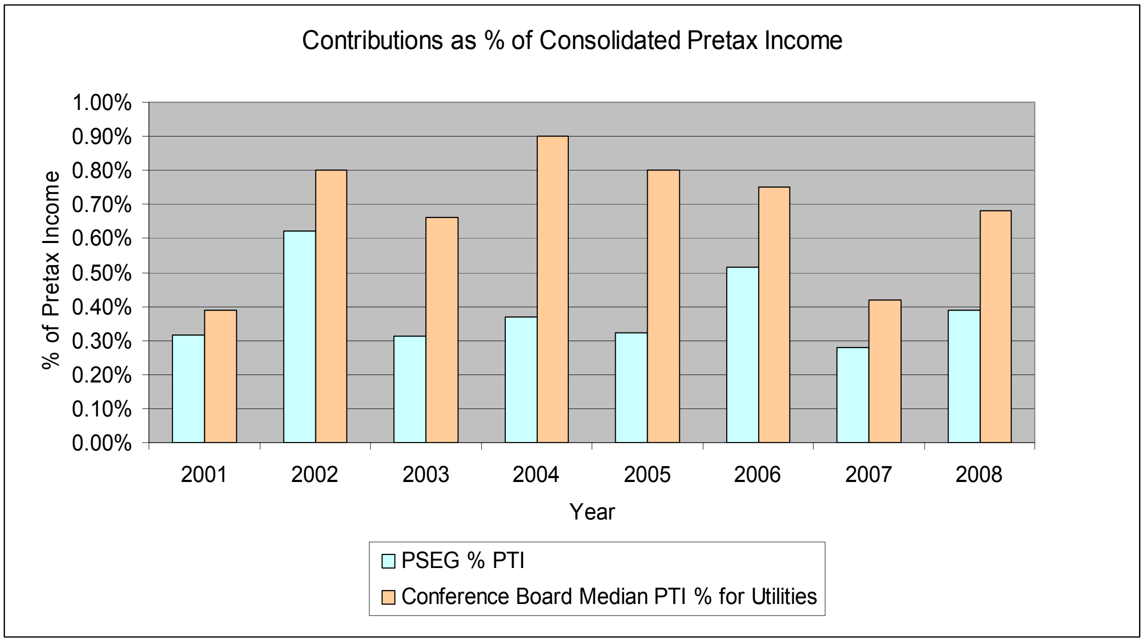
Table 9-7 – PSEG Contributions to Foundation

Year	PSEG Pretax Income	Contributions	PSEG % PTI
2001	$ 1,139,000,000	$ 3,600,000	0.32%
2002	$ 659,000,000	$ 4,100,000	0.62%
2003	$ 1,316,000,000	$ 4,100,000	0.31%
2004	$ 1,167,000,000	$ 4,300,000	0.37%
2005	$ 1,399,000,000	$ 4,500,000	0.32%
2006	$ 1,144,000,000	$ 5,900,000	0.52%
2007	$ 2,389,000,000	$ 6,700,000	0.28%
2008	$ 1,909,000,000	$ 7,400,000	0.39%
2009	$ 2,636,000,000	$ 8,200,000	0.31%

[23] http://www.pseg.com/community/request_faqs.jsp
[24] Response to Discovery, OC-1161.

A common measure used to analyze corporate and corporate foundation giving is total contributions as a percentage of pre-tax income. Below is a comparison between PSEG and corporate contributions of other utilities that participated in a particular Conference Board survey for the years 2001 – 2008.

Table 9-8 – % of Pretax Contributions



Source: Derived from Response to OC-1161

As shown in the chart above, PSEG corporate contributions are consistently less than its peers on a pre-tax income basis.

Community Development

PSEG has a robust community development team that enables the corporation to have a strong presence in the local communities that they serve. This group is headed by Arthur Guida, Director of External Affairs and Community Development. He has five Regional Public Affairs Managers working under him that are assigned and based out of one of the four electric divisions (the Southern division has two offices: Lawrenceville and Moorestown). In addition, he has two other managers that are dedicated specifically to large transmission projects such as the Susquehanna-Roseland project.[25]

The Community Development team uses a variety of means to communicate with the local communities they serve about upcoming projects and other pertinent information from the utility. This team maintains memberships with the New Jersey League of Municipalities, Conference of Mayors and the New Jersey Association of Counties. The regional managers work with local officials as liaisons between the company and the local citizens, ascertaining the community's needs and fostering the best possible relationship between the utility and its customers. The regional managers often serve on the Board of

[25] Interview with Arthur Guida, August 3, 2010.

Directors for various community organizations and provide support to the local chamber of commerce and many nonprofit organizations.[26]

The Community Development group's performance is assessed using two metrics: perception with local and county government leaders and tackling emerging issues. The perception of government leaders is measured using a survey that each manager conducts twice a year for his region that allows the responder to provide feedback on how PSEG and that particular manager are serving that area. Emerging issues are non-routine issues that are brought to the regional manager or PSEG's attention. These issues are documented and tracked from receipt to resolution, with the goal being satisfactory resolution of 80% of the emerging issues. The two managers that interface with customers in connection with the large transmission projects have performance assessments based on progressing towards or achieving desired benchmarks within that project. Arthur Guida is responsible for the overall performance of the Community Development group. [27]

The Community Development group communicates its activities to internal and external stakeholders. Its internal communications consist of monthly newsletters to management, presentations during staff meetings and Arthur's frequent interaction with his direct report, Richard Thigpen and to a lesser extent Anne Hoskins. The most utilized form of communication with external stakeholders is a newsletter that is distributed to community leaders. This newsletter has taken the place of some face-to-face meetings to help reduce some of the cost incurred by the group.[28]

Public Affairs Future Initiatives

In addition to using the balanced scorecard as a performance measurement tool, it can also be used to obtain information on the future initiatives that the Public Affairs division will undertake. Many of the metrics in the 2010 balanced scorecard have initiatives listed to help the Public Affairs group improve upon their results from the 2009 balanced scorecard.

The first metric with a significant number of initiatives is PSEG's commitment to Corporate Social Responsibility. The 2010 performance assessment of this metric is tied to three separate charitable events or organizations. The first goal in this metric is to increase the percentage of participants in the Power of Giving campaign from 19% to 25%. The Power of Giving campaign is for PSEG employees to donate to their favorite charities and the company will match the employee's donation between $20 and $5,000 per year. PSEG plans to develop an online evaluation/reporting tool for certain nonprofit organization grants and streamline the employee matching and volunteer grant programs to increase participation in the Power of Giving campaign. The second goal in the metric is to raise $5,000 for the PSEG Crisis Fund.[29] The Crisis Fund is available to PSEG employees who have experienced a personal or family crisis. PSEG employees contribute to the Crisis Fund. Eligible recipients can receive up to $5,000 in non-taxable dollars for emergency assistance.[30] PSEG held a softball tournament that allowed the Crisis Fund to raise over $5,000, meeting their goal for 2010.[31]

[26] Ibid.
[27] Ibid.
[28] Ibid.
[29] PSEG Website: http://www.pseg.com/info/community/employee/volunteer.jsp#anchor8
[30] PSEG Website: http://www.pseg.com/info/community/employee/crisis_fund.jsp
[31] Interview with Anne Hoskins, August 2, 2010.

Another relevant metric used on the Public Affairs balanced scorecard is County and Local Government perception. This metric (new in 2010) is measured by using a couple of questions from the Regional Public Affairs constituent satisfaction survey. The two questions are:

- How satisfied would you say you are with PSE&G?
- How favorable do you feel towards PSE&G?

Respondents are to use a 0 to 10 scale to give their perception of the utility. PSE&G received an actual score of 8.1 in 2009 and has a goal of achieving an 8.3 score in 2010. PSEG plans to achieve this goal by implementing eight public affairs forums with key municipal stakeholders and distributing twelve electronic newsletters to a network of key opinion elites that will increase by 200 in 2010.[32]

The scorecard also includes a list of Critical Public Affairs Initiatives. These are outlined below along with their specific tasks to help achieve the initiative.

PSEG Initiatives [Begin Confidential]

[32] Ibid

[33] Response to Discovery, OC-1163

- o **[End Confidential]**

PSEG is a member of the Dow Jones Sustainability Index as stated above in this report section. The company has included a balanced scorecard metric in 2010 that tracks the % above the threshold for inclusion in this index. PSEG earned an assessment that was 14% above the threshold for inclusion in 2009. The target % above the threshold in 2010 is 17%. PSEG plans to achieve this goal using the following initiatives:

- Address the performance gaps in the 2009 DJSI survey.
- Develop a better understanding of how the DJSI is used by investors and if there is any correlation of performance with membership.
- Incorporate understanding of scorecard into DJSI measurement system.[35]

[34] Response to Discovery, OC-1163.
[35] Ibid.

10. FINANCE

This Chapter addresses PSEG's financing activities, its cost of capital, and the implications of diversification on utility operations.

Summary of Findings

1. PSEG has a dividend payout target of 40% - 50%. Utility payouts to the parent are generally measured against equity ratio effects. Financing activities for the utility seems to be driven by achieving and maintaining a capital structure consistent with strong credit ratings. Overland agrees with this approach and these commitments.

2. The PSEG dividend payout ratio was similar to its peers for the period 2007 through 2009.

3. PSEG has an estimated cost of equity that is more aligned with utilities with significant unregulated operations rather than pure-play utility companies as measured by the Capital Asset Pricing Model (CAPM). This observation makes sense, as non-regulated operations accounted for more than 70% of the net income from operations from 2007 to 2009.

4. The PSE&G equity ratio has increased from 2007 to 2009 in a concerted effort by the utility to rely less on debt financing as the credit markets have tightened since the economic downturn began in 2008.

5. PSE&G has an overall strategy of achieving and maintaining investment grade credit rating on its debt. This is primarily accomplished by managing the Company's equity ratio to be approximately 51.2%, as outlined in the most recently decided electric and gas base rate case.

6. Both PSE&G and PSEG maintain investment grade credit ratings and have credit ratings outlooks of stable from both S&P and Moody's as of December 31, 2009. These outlooks were changed to positive for both PSEG and PSE&G for S&P and Moody's during 2011.

7. Substantially all of PSE&G's assets are pledged under the utility's First and Refunding Mortgage. In addition, third-party encumbrances exist relating to certain utility-owned real estate, which are subordinate to the First and Refunding Mortgage.

8. PSE&G debt primarily consists of first mortgage bonds and long-term transition bonds issued by PSE&G Transition Funding I and II.

9. PSEG management believes that it has taken the necessary steps to insulate PSE&G from potential financial difficulties of its non-regulated affiliates. However, these measures have not been sufficient for S&P to differentiate PSE&G's corporate rating from its parent, while the Moody's ratings reflect a one notch differential.

10. Although PSE&G does not participate in the PSEG money pool, PSEG is able to draw funds out of the money pool and its credit facility and infuse the capital into the utility. There are no restrictions on the funds drawn by PSEG from its credit facility.

11. During the credit market crisis, PSE&G was able to continue issuing debt and to access the commercial paper market, albeit on a somewhat more limited basis for a short period of time.

12. PSE&G has access to a $600 million syndicated credit facility to supplement its day-to-day working capital needs. From January 2008 to October 2009, the predominant use of the credit facility was as a back-stop to the company's commercial paper program. During this time period, the maximum amount of commercial paper outstanding was $485 million.

13. PSE&G received a decision on the electric and gas base rate case that was submitted in May 2009. The decision was rendered in June 2010 giving PSE&G an overall $100 million increase in electric and gas rates, based on a return on equity (ROE) of 10.3%.

14. PSEG also has a separate credit facility available to it totaling $1 billion as of September 30, 2010.

Equity

PSE&G

PSE&G is a wholly-owned subsidiary of PSEG. As such, PSE&G's common stock is not publicly traded, and it does not issue its own stock to raise capital for its operations. Any changes to common equity are primarily the result of three items – earnings, dividends, and capital infusions. In addition to the management of dividends as described later in this chapter concerning ring-fencing measures, the amount of dividends paid by PSE&G is restricted by New Jersey statute. PSE&G cannot make distributions to shareholders if it would result in its inability to pay its debts or if its total liabilities exceeded its total assets after giving rise to the distribution.[1]

The amount of dividends paid by PSE&G to its parent in the last three years was:[2]

- 2007 - $200 million
- 2008 - $0
- 2009 - $0

This compares to PSE&G net income of:[3]

- 2007 - $380 million
- 2008 - $364 million

[1] N.J.S.A. 14A:7-14.1.
[2] Response to Discovery, OC-33 (UPDATE).
[3] 2009 PSEG 10-K pages 174-175.

- 2009 - $325 million

Other than dividends, PSE&G made no capital distributions to its parent for the years 2007, 2008, or 2009.[4]

PSEG made no capital contributions to PSE&G in either 2007 or 2008. However, in May 2009, PSEG contributed $250 million to PSE&G.[5]

Other PSEG Subsidiaries

The following table summarizes the material equity transactions of PSEG's other significant subsidiaries:

Table 10-1 – Equity Activity

Equity Activity		
Description	PSEG Power	PSEG Energy Holdings
Income (Loss) from Continuing Operations:		
2007	$1,000,000,000	$12,000,000
2008	1,115,000,000	(468,000,000)
2009	1,189,000,000	72,000,000
Dividends to Parent:		
2007	(1,075,000,000)	--
2008	(500,000,000)	--
2009	(940,000,000)	--
Other Capital Distributions to Parent:		
2007	--	(355,000,000)
2008	--	--
2009	--	--
Capital Contributions from Parent:		
2007	--	--
2008	--	--
2009	230,000,000	--
Sources: PSEG 2009 Form 10-K (p. 2) and Responses to Discovery, OC-33 (Update), OC-34 (Update), and OC-35 (Update).		

The preceding table demonstrates that the parent is not contributing large amounts of funds on a recurring basis to its two principal unregulated subsidiaries. Coupled with the PSE&G data, there is little evidence to suggest that utility operations are being used by the parent to regularly fund affiliates. In fact, at least during this period, the opposite condition appears to be the case.

[4] Response to Discovery, OC-35.
[5] Response to Discovery, OC-34.

Dividend Policy

PSEG

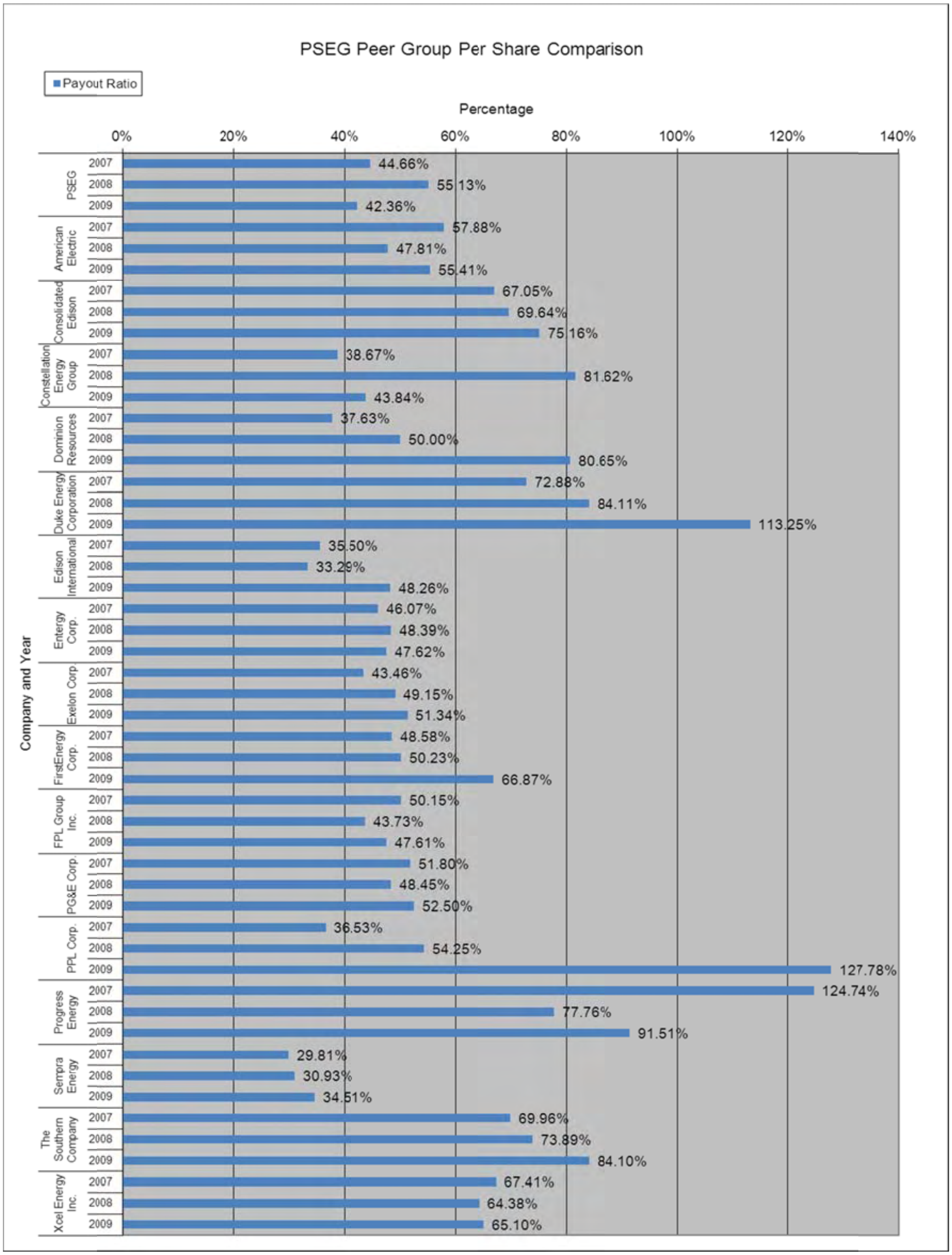
The review and recommendation of dividend policy, including the amount of dividends to be paid to PSEG common stock shareholders are performed by the Finance Committee of the PSEG Board. Its analysis is made in the overall context of PSEG financial objectives and financial performance. The criteria for dividend recommendations in 2009 included:

- Determining what the dividend payout expectation is from the financial community
- Achieving a target payout ratio range of 40% - 50%
- Providing a competitive dividend yield with respect to PSEG's peer group
- Maintaining PSEG's long-term credit profile[6]

The dividend payout ratio compared against the S&P 500 electric companies and the PSEG peer group average is also tracked and taken into consideration. The following table compares PSEG's historical dividends to that of a sample of its peers:

[6] Response to Discovery, OC-111.

Table 10-2[7] – PSEG Peer Group Per Share Comparison



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[7] Source: The peer group is obtained from Dr. Michael J. Vilbert's testimony in the 2009 PSEG rate case, which is found in the response to OC-135. Constellation Energy Group was omitted from the peer group as its dividend payout ratio was greatly affected by one-time events in 2008 and 2009, thus creating outliers in the analyzed data

PSEG's dividend payout ratio for 2007, 2008 and 2009 was 45%, 55% and 42%, respectively. This meets the target dividend payout ratio approved by the Board and falls in line with PSEG's peers as shown in the above table.

PSE&G

Dividend payout ratios are not a primary driver of the amount of dividends paid by PSE&G to its parent. This is demonstrated in the following table which shows a wide range of PSE&G dividend payout ratios in the past three years:

Table 10-3 – PSEG Dividends to Parent

Public Service Electric & Gas Dividends to Parent				
Company	Year	Total Dividends	Net Income	Payout Ratio
PSE&G	2009	$0	$325,000,000	0%
	2008	$0	$364,000,000	0%
	2007	$200,000,000	$380,000,000	53%
Source: Derived from responses to OC-33 (UPDATE) and PSEG's 2009 10-K.				

Instead of establishing a standard level of dividends paid by PSE&G to the parent company, PSEG is remitted a dividend that allows PSE&G to comply with its capital structure policy, which is designed to maintain strong investment grade credit ratings and ensure access to the capital markets.[8] The historical equity ratios for PSE&G were 44.85%, 44.46%, and 47.19% for 2007, 2008, and 2009 respectively.[9]

PSE&G remitted to PSEG a dividend of approximately $150 million during the 2010 fiscal year.[10]

Cost of Capital and Capital Structure

PSEG

This section provides an independent estimate of the PSEG cost of equity for the audit period as well as a comparison between the cost of equity for consolidated utility holding companies with regulated and unregulated operations and pure play utility companies with substantially all regulated operating activities.

[8] When asked to define "strong investment grade credit rating", PSEG cited ratings of A- with S&P and A2 with Moody's (response to Discovery, OC-1029).
[9] Derived from Response to Discovery OC-115.
[10] PSEG 2010 10-K.

Table 10-4 – Cost of Equity of Utilities with Significant Unregulated Operations

Public Service Enterprise Group, Inc.
Cost of Equity Estimate of Utilities with Significant Unregulated Operations
Based on Capital Asset Pricing Model
Risk-Free Rate Based on Yield of Intermediate-term Government Bond as of Dec 31, 2009
Risk Premium Based on Intermediate-term Government Bond Rate
As of December 31, 2009

Line #	Peer Utilities [1]	Risk Free Interest 12/31/09 [2]	Beta [3]	Equity Risk Premium [4]	Cost of Equity [5]
1	Public Service Enterprise Group	2.42%	0.90	7.2%	8.90%
2	Constellation Energy Group	2.42%	0.80	7.2%	8.18%
3	Edison International	2.42%	0.80	7.2%	8.18%
4	Entergy Corp	2.42%	0.70	7.2%	7.46%
5	Exelon	2.42%	0.85	7.2%	8.54%
6	FirstEnergy Corp	2.42%	0.85	7.2%	8.54%
7	FPL Group Inc	2.42%	0.85	7.2%	8.54%
8	PPL Corp	2.42%	0.70	7.2%	7.46%
9	Sempra Energy	2.42%	0.85	7.2%	8.54%
10	Xcel Energy Inc	2.42%	0.65	7.2%	7.10%
11	Peer Group Average				8.03%

Reference:
Column [1] Selected Companies as identified "Less Regulated" in Response to OC-792.
Column [2] Stocks, Bonds, Bills and Inflation - Ibbotson 2010 Yearbook: Yield on an Intermediate-Term Government Bond as of December 31, 2009
Column [3] Value Line Investment Survey - February 5, 2010; February 26, 2010; March 26, 2010 - Approach I, Workpaper Schedule B-4
Column [4] Intermediate-Horizon Equity Risk Premia - Ibbotson 2010 Yearbook (S&P 500 total returns minus intermediate-term government bond income returns)
Column [5] (Product of Column [3] and Column [4]) plus Column [2]

Line 11 Average of Lines 2 through 10

Table 10-5 – Cost of Equity of Utilities with Predominately Regulated Operations

Public Service Enterprise Group, Inc.
Cost of Equity Estimate of Utilities with Predominantly Regulated Operations
Based on Capital Asset Pricing Model
Risk-Free Rate Based on Yield of Intermediate-term Government Bond as of Dec 31, 2009
Risk Premium Based on Intermediate-term Government Bond Rate
As of December 31, 2009

Line #	Peer Utilities [1]	Risk Free Interest 12/31/09 [2]	Beta [3]	Equity Risk Premium [4]	Cost of Equity [5]
1	Public Service Enterprise Group	2.42%	0.90	7.2%	8.90%
2	American Electric Power Co Inc	2.42%	0.70	7.2%	7.46%
3	Consolidated Edison Inc	2.42%	0.65	7.2%	7.10%
4	Dominion Resources Inc.	2.42%	0.70	7.2%	7.46%
5	Progress Energy Inc	2.42%	0.60	7.2%	6.74%
6	Southern Co	2.42%	0.55	7.2%	6.38%
7	Xcel Energy Inc	2.42%	0.65	7.2%	7.10%
8	Peer Group Average				7.04%

Reference:

Column [2] Stocks, Bonds, Bills and Inflation - Ibbotson 2010 Yearbook: Yield on an Intermediate-Term Government Bond as of December 31, 2009
Column [3] Value Line Investment Survey - February 5, 2010; February 26, 2010; March 26, 2010 - Approach I, Workpaper Schedule B-4
Column [4] Column [1] Selected Companies as identified "Mostly Regulated" in Response to OC-792. (S&P 500 total returns minus intermediate-term government bond income returns)
Column [5] (Product of Column [3] and Column [4]) plus Column [2]

Line 8 Average of Lines 2 through 7

As shown in the two tables above, PSEG's cost of equity is more similar to utility companies with substantial unregulated operations. These companies have on average a cost of equity that is approximately 100 basis points higher than their more regulated counterparts. More than 70% of PSEG's Income from Continuing Operations from 2007 through 2009[11] originated from PSEG Power, an unregulated subsidiary of PSEG.

PSE&G

"PSE&G's weighted average cost of capital (WACC) reflects the Company's embedded cost of long-term debt, embedded cost of preferred stock, the BPU-set rate for customer deposits and the Company's cost of common equity weighted by the each type of financing's respective percent of target capitalization."[12]

In November 2006, the BPU rendered decisions in Docket Nos. ER02050303 and GR05100845 that established rates of return based upon the following capital structure:

[11] PSEG 2009 10-K.
[12] Response to Discovery, OC-43.

Long-term Debt	50.6434%
Customer Deposits	0.6831
Preferred Stock	1.2708
Common Equity	47.4027
Total	100.0000%

The Company subsequently targeted its capital structure to reflect that structure.

Over the past year the financial community, given changes in the economy and the utility's requirement to increase capital investment in its business, has been demanding that utilities strengthen their balance sheets. In response, the Company began moving its capital structure toward a target that reflects 51.2% common equity."[13] The Company sponsored a capital structure in the 2009 rate case filed with the New Jersey Board of Public Utilities that follows:

Table 10-6 – Capital Structure

	Amount ($ millions)	Percent	Embedded Cost	Weighted Cost
Long-Term Debt	$3,531	46.60%	6.21%	2.89%
Preferred Stock	80	1.06%	5.03%	0.05%
Customers' Deposits	87	1.15%	2.34%	0.03%
Common Equity	3,879	51.19%	11.50%	5.89%
Total	$7,577	100.00%		8.86%

Source: OC-135 (Mark Karher's testimony in BPU Docket No. GR09050422)

The target equity ratio in the table above represents an increase over the same ratio filed in the 2006 rate case. Company management is striving to increase the strength of PSE&G's balance sheet. The credit markets have become more challenging in terms of acquiring debt to fund capital expenditures. To fund the capital expenditures that are necessary to continue to provide quality service at a reasonable economic cost, the utility must work to reduce the relative level of debt on its balance sheet and increase the relative level of equity. PSE&G believes that the target ratio displayed above is required to meet its obligations to provide safe, adequate, and reliable service.[14] The utility has had an equity ratio of 53% or higher in the past couple of years. This has allowed the utility, in 2010, additional flexibility in refinancing some of its debt.[15]

The PSE&G cost of common equity was estimated in a study performed by Dr. Michael J. Vilbert in connection with the rate case filing in 2009. His cost of equity (11.50% shown above) is based on the average cost of capital of each firm in a peer group of electric utilities whose business risks were similar to that of PSE&G and PSE&G's capital structure as filed with the New Jersey BPU.[16]

[13] Response to Discovery OC-43
[14] Response to Discovery OC-135
[15] Interview with Mark Kahrer, July 7, 2010.
[16] Response to Discovery OC-135 (Dr. Michael J. Vilbert's testimony in BPU Docket No. GR09050422)

In the rate case filing in 2009, PSE&G asserted that the ROE would be estimated at 8.10% for electric distribution and 7.30% for gas distribution in the 2009 test year without a change in rates. Both figures are well below the then current authorized figures of 9.75% and 10% for electric and gas distribution, respectively, as well as the 11.50% cost of equity shown above.[17] PSE&G requested an ROE of 11.5% in its 2009 rate case, which was settled in June 2010 with an ROE of 10.3%.[18]

Debt

PSEG Services Treasury is responsible for PSE&G financing, including debt issuances and redemptions.[19] PSEG, the parent company, did not hold any debt as of December 31, 2009. All of the Enterprise's debt was held at the subsidiary level at the end of 2009. Below is a table with the roll-forward of debt for PSE&G from 2007 to 2009.

Table 10-7 – Debt Rollforward

PSE&G Debt Rollforward ($M)							
Description	**As of 12/31/2007**	**Issuances**	**Redemptions**	**As of 12/31/2008**	**Issuances**	**Redemptions**	**As of 12/31/2009**
First Mortgage Bonds (A)	$ 477	$ 300	$ (157)	$ 620	$ -	$ -	$ 620
Pollution Control Bonds	672	100	(494)	278	-	(105)	173
Medium-Term Notes (Unsecured)	2,208	675	(250)	2,633	250	(99)	2,784
Net Unamortized Discount	(5)	(3)	-	(8)	-	2	(6)
Total Long-Term Debt	$ 3,352	$ 1,072	$ (901)	$ 3,523	$ 250	$ (202)	$ 3,571
Long-Term Transition Bonds - PSE&G Funding (B)	$ 1,709	$ -	$ (179)	$ 1,530	$ -	$ (187)	$ 1,343
Commercial Paper	$ 65	$ -	$ (46)	$ 19	$ -	$ (19)	$ -
Total Debt	**$ 5,126**	**$ 1,072**	**$ (1,126)**	**$ 5,072**	**$ 250**	**$ (408)**	**$ 4,914**

Source: Derived from PSEG 2008 and 2009 10-K
(A) The maturity of these bonds ranged from 2008 to 2039. They are secured by essentially all property of PSE&G pursuant to its First and Refunding Mortgage.
(B) Long-Term Transition Bonds are solely for the purpose of purchasing transitional bond property of PSE&G, which is pledged as collateral to the trustee.
Note 1: Balances for Long-Term Debt and Long-Term Transition Bonds include current maturities of long-term debt.

PSE&G's debt is scheduled to mature over the next thirty years. A schedule of those maturities is summarized in the following table:

[17] Response to Discovery, OC-135
[18] The cost of equity determinations made by Overland in this section are primarily considered as relative measures of diversified holding company ROEs, versus regulated utilities. These calculations should not be interpreted as a robust analysis of PSE&G's cost of equity.
[19] Response to Discovery, OC-1003.

Table 10-8 – PSE&G Scheduled Debt Maturities

PSE&G Scheduled Debt Maturities ($M) for Outstanding Long-Term Debt as of December 31, 2009				
Year	PSE&G	PSE&G Trans. Funding I	PSE&G Trans. Funding II	Total
2010	$ 300		$ 12	$ 312
2011		232	11	243
2012	300		1	301
2013	725	454	20	1,199
2014	250	220		470
2015	-	370	23	393
2016	171			171
2018	400			400
2020	9			9
2021	134			134
2025	23			23
2032	150			150
2035	250			250
2036	250			250
2037	365			365
2039	250			250
Total	**$ 3,577**	**$ 1,276**	**$ 67**	**$ 4,920**
Note: The Total Debt Maturity equals debt plus net unamortized discount from the previous table.				
Source: Response to Discovery, OC-81 and PSEG 2009 10-K				

In terms of total long-term debt outstanding, 51 percent matures in Years 1 - 5, 20 percent matures in Years 6 - 10, 3 percent matures in Years 11 - 15, and 26 percent matures in Years 16 - 30.

Reviewing the current plan for utility capital investment, PSE&G projects the future debt level to be as follows in the table below:

[Begin Confidential] Table 10-9 – Projection of Future Financing Activity

Projection of Future Financing Activity ($M)			
Year	New Issue	Maturity	Total

[redacted]

[20] [End Confidential]

PSE&G issues all of its debt through public placements. Morton Plawner, Vice President and Treasurer, indicated that this is the most liquid market and it also has the lowest debt issuance costs. PSE&G also has a five year credit facility (credit revolver) in the amount of $600 million that expires in 2012.[21]

PSE&G Affiliates

Earlier in this chapter, we noted that PSE&G has been a net beneficiary of equity funding from the end of 2006 to the end of 2009. As will be discussed later in this chapter, PSE&G is not a party to any money pool arrangement. Both of these facts suggest that PSE&G is not indirectly supporting the operations of its most significant affiliates.

PSE&G's affiliates reported the following long-term debt transactions in 2008 and 2009:

Table 10-10 – Debt Activity

Debt Activity			
Description	PSEG (the parent)	PSEG Power	PSEG Energy Holdings
December 31, 2007 Balance	**$298,000,000**	**$2,902,000,000**	**$1,137,000,000**
Redemption of Long-Term Debt	(49,000,000)	--	(632,000,000)
Change in Unamortized Discount	--	1,000,000	--
December 31, 2008 Balance	**249,000,000**	**2,903,000,000**	**505,000,000**
Reclassification of Non-Recourse Project Debt	--	280,000,000	48,000,000
Redemption of Long-Term Debt	(249,000,000)	(574,000,000)	(16,000,000)
Issuance of Long-Term Debt	--	209,000,000	--
Debt Modification	(35,000,000)	303,000,000	(368,000,000)
Other	(3,000,000)	--	--
December 31, 2009 Balance	**$(38,000,000)**	**$3,121,000,000**	**$169,000,000**
Sources: Derived from PSEG 2008 Form 10-K (pp. 141-147) and 2009 Form 10-K (pp. 141-146).			

In 2009, PSEG Power completed an exchange offer with eligible holders of PSEG Energy Holdings' 8.50% Senior Notes due in 2011 in order to manage long-term debt maturities. In this transaction, $368 million of PSEG Energy Holdings' notes were exchanged for $404 million -- $303 million which was in the form of PSEG Power 5.32% Senior Notes due in 2016 and $101 million in PSEG Power cash. The resulting

[20] Response to Discovery, OC-1031.
[21] Response to Discovery, OC-977.

premium of $36 million ($404 million less $368 million) was deferred and recorded on the parent's records since the debt exchange was between two wholly-owned subsidiaries.[22]

Absent this transaction, PSEG Power's long-term debt decreased slightly between year-end 2007 and 2009 (approximately 3%). On the other hand, PSEG Energy Holdings' long-term debt was paid down substantially in those same two years. Cash used to pay down this debt is attributable to the proceeds of selling its investment in SAESA Group, which consists of several distribution, transmission, and generation companies located in Chile.[23]

Credit Ratings and Credit Quality

Regulatory risk is considered a central component of utility business risk. S&P uses a five-category ranking from most supportive to least credit supportive in ranking state jurisdictions. It currently classifies no regulatory jurisdictions in the category as "most credit supportive", and only eight as "more credit supportive". New Jersey is considered "credit supportive", along with twenty other states.[24]

PSEG is considered to have a medium business risk profile, similar to most diversified United States utility holding companies. PSE&G contributes about 39% of the consolidated cash flow for PSEG.[25] PSEG Power and PSEG Energy Holdings LLC have moderately-high and high risk profiles, respectively.[26] The rating agencies, and particularly S&P, view the corporate credit ratings of the utility subsidiary to be directly linked to the ratings of its parent company.

PSE&G designs its financial policies with the purpose of maintaining a strong credit profile and strong credit ratings. The most important credit objective of PSE&G is to obtain and maintain a credit rating of "A" on its secured debt. PSE&G believes that the key measure to focus on in order to achieve that rating is the regulatory equity ratio, which the utility currently targets at 51.2%.[27] PSE&G's dividend and borrowing policies are generally premised on the utility maintaining its regulatory equity ratio.

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[22] PSEG 2009 Form 10-K (p. 144). In 2009, PSEG Energy Holdings transferred two Texas generation facilities to PSEG Power (PSEG 2009 Form 10-K, p. 14).
[23] PSEG 2009 Form 10-K (p. 106).
[24] Response to Discovery OC-7 , S&P's Assessment of Regulatory Climates for U.S. Investor-Owned Utilities.
[25] Response to Discovery OC-6, Standard & Poor's Ratings Direct, dated 3/31/09.
[26] Response to Discovery OC-6, Moody's Credit Opinion, dated 10/15/09
[27] Response to Discovery OC-1031

PSEG and PSE&G Credit Ratings

Table 10-11 – PSEG Ratings Summnary

PSEG Ratings Summary			
Year	**Security**	**S&P**	**Moody's**
2009	Corporate Credit Rating	BBB	Baa2
	Credit Ratings Outlook	Stable	Stable
2008	Corporate Credit Rating	BBB	Baa2
	Credit Ratings Outlook	Stable	Stable
2007	Corporate Credit Rating	BBB	Baa2
	Credit Ratings Outlook	Stable	Negative
Note: In some instances, Overland received multiple rating reports for the same year. In such instances, Overland relied on the most recent issue to include in the above summary.			
Source: Derived from responses to discovery OC-6 and OC-817			

Table 10-12 – PSE&G Ratings Summary

PSE&G Ratings Summary			
Year	**Security**	**S&P**	**Moody's**
2009	Sr. Secured	A-	A2
	Sr. Unsecured	(1)	Baa1
	Commerical Paper	A2	P-2
	Preferred Stock	BB+	Baa3
	Corporate Credit Rating	BBB	Baa1
	Corporate Credit Rating Outlook	Stable	Stable
2008	Sr. Secured	A-	A3
	Sr. Unsecured	(1)	Baa1
	Commerical Paper	A2	P2
	Preferred Stock	BB+	Baa3
	Corporate Credit Rating	BBB	Baa1
	Corporate Credit Rating Outlook	Stable	Stable
2007	Sr. Secured	A-	A3
	Sr. Unsecured	(1)	Baa1
	Commerical Paper	A2	P2
	Preferred Stock	BB+	Baa3
	Corporate Credit Rating	BBB	Baa1
	Corporate Credit Ratings Outlook	Stable	Negative
Note 1: This information was not available through discovery.			
Note 2: Where Overland received multiple rating reports for a year, Overland relied on the most recent issue to include in the summary above.			
Source: Derived from responses to OC-117 & OC-818 (UPDATE)			

In early 2009, Standard and Poor's characterized its view of PSE&G operations as follows:

> *The excellent business profile reflects PSE&G's lower risk regulated transmission and distribution businesses and overall solid regulatory environments. The distribution rates are regulated by the New Jersey Board of Public Utilities and the transmission rates are regulated by the Federal Energy Regulatory Commission (FERC). Standard & Poor's assesses the New Jersey regulatory environment as in the credit supportive category (see Standard & Poor's Assessments Of Regulatory Climates For U.S Investor-Owned Utilities, Nov. 25, 2008). The transition to deregulation has been relatively uneventful and is viewed as favorable for credit quality. As part of the last electric and gas distribution rate cases, PSE&G accepted a rate freeze and the company is expected to file new electric and gas rate cases later in 2009 with rates effective in 2010. Additionally, we view the existing regulatory mechanisms as supportive of credit quality. These include the pass-through of gas and electric commodities and the societal benefits charges. On the transmission side, the FERC has approved formula rate treatment, incentive rate treatment, and recovery of construction work in progress in rate base, which we also view as credit supportive.*[28]

In a July 17, 2008 credit rating action report, Moody's released the following statement regarding the PSE&G ratings:

> *On July 17, 2008, Moody's changed the rating outlook for PSE&G to stable from negative and affirmed the Issuer Rating of PSE&G at Baa1. The change in PSE&G rating outlook to stable reflects the modest improvement in the company's financial metrics since 2005 and Moody's expectation that further modest improvements are likely over the next two years.*

As of its March 2010 report, the S&P credit rating for PSE&G was BBB/Stable. It identified the following major negative factors implicit in the rating:

- Affiliation with Public Service Enterprise Group's more volatile non-regulated business
- Large proposed capital expenditures concurrent with a weak economy

S&P considers PSE&G's corporate rating on the basis of the consolidated ratings of its parent, PSEG, as a diversified energy company.[29]

[28] Response to Discovery, OC-6, Standard and Poor's Ratings Direct, dated March 31, 2009.
[29] Response to Discovery, OC-6 (UPDATED) Standard and Poor's Ratings Direct, dated March 26, 2010.

Collateral Requirements

Regulated Businesses

Substantially all of PSE&G's assets (except cash, receivables, inventory, corporate obligations, and corporate securities) are pledged under PSE&G's First and Refunding Mortgage.[30] Various real estate assets owned by the utility are encumbered by easements, leases, licenses and other third party liens. These third party encumbrances are subordinate to the First and Refunding Mortgage mentioned above.[31]

Unregulated Businesses

PSEG has two principal unregulated businesses – PSEG Power and PSEG Energy Holdings.

PSEG Power has unconditionally guaranteed payments by its subsidiaries in commodity-related transactions to support current exposure, interest, and other costs on sums due and payable in the ordinary course of business. These guarantees assist the subsidiaries in gaining more favorable credit conditions. For PSEG Power to incur liability for these agreements, its subsidiaries would have to exhaust all the credit granted to them by the parties to which PSEG Power has provided a guarantee and all of the contracts would have to be "out of the money". This is not a likely scenario as the portfolio positions obtained by PSEG subsidiaries are somewhat offsetting in nature.[32]

PSEG Power is subject to posting collateral or margin on certain commodity-related contracts. PSEG Power also enters into futures and option transactions which require a cash margin deposit to enter into the transaction. In both instances, the market values of the commodity influence the amount of margin required to enter into the transaction.[33] For example, when energy prices increased significantly in the second half of 2008, the amount PSEG was required to post for margin increased significantly as well. As of December 31, 2009, there were letters of credit and cash margin posted in the amount of $91 million. If PSEG Power were to lose its investment grade rating, which would take a two level decrease in their current rating, an additional $986 million would have to be added to their collateral requirements. At no point in 2008 or 2009 did PSEG Power not have the additional liquidity available under existing credit facilities to meet any additional collateral requirements.[34]

PSEG Energy Holdings also has collateral pledged in the form of letters of credit. These letters are related to bank facility support, capital investments, etc. and do not fluctuate with the commodity or market prices as do the collateral guarantees within the PSEG Power consolidated entity. PSEG Energy Holdings has approximately $58 million pledged as collateral, which is issued under PSEG's corporate

[30] Response to Discovery, OC-38.
[31] Response to Discovery, OC-780.
[32] PSEG 2009 10-K p. 128
[33] 2009 PSEG Form 10-Q p. 23.
[34] PSEG 2009 10-K pp. 128-129

debt facility. The collateral is in connection with performance guarantees relating to construction and workers compensation.[35]

Mechanisms to Protect PSE&G from the Financial Problems of Affiliates (Ring-Fencing)

For some time, regulators have been concerned about the negative financial implications that holding companies and affiliates might have on regulated utilities. Investments in unregulated businesses are often seen as riskier than regulated activities. In a worst case scenario, the difficulties of a more volatile, unregulated subsidiary could theoretically bankrupt a parent and its other holdings, such as a regulated utility, if the parent siphons assets out of its financially healthy subsidiaries to unsuccessfully stem the losses of its weakening subsidiaries. Although such an occurrence might be remote, the three major credit reporting agencies have recognized a linkage between the credit ratings of utility companies within a holding company structure.[36]

In the case of Standard & Poor's, their linkage of the regulated utility to its parent was recently evidenced in a March 26, 2010 RatingsDirect report on PSE&G, which indicated that "the ratings on Public Service Electric & Gas Co. are based on the consolidated credit profile of its parent, Public Service Enterprise Group Inc." A specific weakness of PSE&G was its "affiliation with Public Service Enterprise Group's more volatile non-regulated businesses".[37]

When asked what ring-fencing measures PSE&G has taken, the utility listed several measures taken to insulate the utility from other PSEG affiliates that are perceived to have a higher business risk. These measures are listed below:

- PSE&G assets secure only the PSE&G Mortgage Bonds.
- PSE&G asset sales must be approved by the BPU, in accordance with the BPU's regulations.
- PSE&G issues its own securities and has its own credit agreements.
- PSE&G's securities and credit agreements do not contain cross-defaults to the other PSEG companies.
- PSE&G's securities and credit agreements do not contain ratings triggers to the other PSEG companies.
- PSE&G maintains separate cash accounts, and does not participate in any PSEG money pool.
- PSE&G does not lend to or borrow from PSEG or subsidiaries.
- Dividend payments are approved by PSE&G's Board of Directors which includes at least 40% independent directors, as required by BPU rules.
- PSE&G's dividend payments are principally based upon its capital structure policy which is designed to achieve strong investment grade credit ratings.[38]

[35] Response to Discovery OC-119 (UPDATE)
[36] Grygiel, Dr. Fred and Garvey, John. "Fencing in the Regulated Utilities", Public Utilities Fortnightly, August 2004.
[37] Response to Discovery OC-6 (UPDATE) S&P Ratings Direct for Public Service Electric and Gas Co., March 26, 2010.
[38] Response to Discovery, OC-37

It was noted in a Moody's credit report dated October 15, 2009 that if capital market financing either became unavailable or unattractive to PSE&G, that PSE&G could obtain funds indirectly from PSEG resources, including the money pool.[39] During Overland's interview with Morton Plawner, Vice President and Treasurer, he confirmed that it is possible for PSEG to obtain funds from the money pool and infuse the cash into the utility. Mr. Plawner stated in the interview that this has been done in the past. Furthermore, he noted that PSEG is permitted to borrow money from their $1 billion credit facility and loan or infuse equity from these funds into PSE&G, as there are no restrictions on the cash used by the parent from its credit facility.[40]

Response to the Financial Crisis (2007-2008)

For years, steadily decreasing interest rates backed by the U.S. Federal Reserve and large inflows of foreign funds created an environment in which easy credit became the norm. This resulted in a domestic housing construction boom and debt-financed consumption that was ultimately unsustainable. When the U.S. housing market peaked in 2005-2006, borrowers who had over-extended themselves to purchase real estate began to default. Institutional investors in securities tied to these defaulting loans began losing money, further exacerbated by their decision to leverage their investments through borrowing. As losses on these loans mounted, the ability of financial institutions to lend was severely impaired, and access to the credit markets began to seize up for all but the most credit-worthy companies.

By the latter half of 2008, a number of financial institutions faced imminent collapse. In short succession, the Federal National Mortgage Association and the Federal Home Loan Mortgage Corporation were placed into conservatorship, Lehman Brothers filed for bankruptcy, Merrill Lynch agreed to be bought by Bank of America to avoid its own financial undoing, AIG was infused with capital from the federal government, and a federal program was created to "bail out" other financial institutions. Within the utility industry, Constellation Energy Group (Constellation) first agreed to be purchased by MidAmerican Energy Holdings to shore up its finances and then later accepted an alternative proposal by the French company, EDF Group, to invest in its nuclear operations.

Unlike Constellation, PSE&G was able to weather these uncertain times because of its solid credit ratings. PSE&G issued $275 million of medium-term notes in December 2008 and remarketed $100 million of Salem County Authority pollution control bonds as a letter of credit-enhanced variable rate demand bonds in November 2008 during the height of the credit crisis.[41]

From an investment standpoint, PSE&G chose to transfer all of its short-term investments from money market mutual funds to high quality commercial paper in 2008 after the Reserve Fund's share value dropped below $1.[42] PSE&G did not have any investments in the Reserve Fund, but chose to transfer to

[39] Response to Discovery, OC-6 Moody's Credit Opinion: Public Service Enterprise Group Inc.
[40] Interview with Morton Plawner, Treasurer, July 9, 2010.
[41] Response to Discovery, OC-41.
[42] Response to Discovery, OC-41.

a safer investment for precautionary reasons. During the period of this audit, PSE&G avoided money market mutual funds as a place to invest excess cash or cash equivalents.[43]

Internally, company management reported that there was heightened intercompany correspondence during this time, presumably to address in a direct and timely manner any potential issues involving the financial markets or counterparties with which PSE&G and affiliates transact business.[44] The Board was informed of the procedures in place at the company that would prevent a Constellation-like meltdown.[45]

Cash Management

[Begin Confidential]

[End Confidential][46]

According to management, the PSEG Treasury Department is specifically evaluated on its ability to accurately project cash flows.[47] **[Begin Confidential]**

[End Confidential][48]

Credit Facility

While PSE&G's capital investments are largely funded by internal operations and periodic long-term debt issuances, day-to-day working capital needs are supplemented by short-term debt borrowings. To accomplish this, PSE&G has a $600 million multi-year syndicated credit facility which serves as a backstop for its commercial paper program. In addition to supporting the commercial paper program, the credit facility can be used for funding and letters of credit.[49]

The entire PSE&G credit facility is currently set to expire on June 15, 2012 with the exception of $28 million which will expire a year earlier. The syndicate backing the credit facility is composed of eighteen financial institutions whose participation ranges from 2.5% to 11.7%.[50]

[43] Interview with Morton Plawner (Vice President and Treasurer), July 9, 2010.
[44] Interview with Morton Plawner (Vice President and Treasurer), July 9, 2010.
[45] Interview with Mark Kahrer (Vice President Finance – PSE&G), July 7, 2010.
[46] Response to Discovery, OC-40 (Restricted).
[47] Interview with Morton Plawner (Vice President and Treasurer), July 9, 2010.
[48] Response to Discovery, OC-40 (Restricted).
[49] PSEG 2009 Form 10-K (pp. 65 and 77).
[50] Response to Discovery, OC-53.

PSE&G has utilized the credit facility since January 1, 2008 as follows:

[Begin Confidential] Table 10-13 – PSE&G Credit Facililty Utilizations

PSE&G Credit Facility Utilization				
Month	Direct Funding		Commercial Paper	
	Minimum Balance	Maximum Balance	Minimum Balance	Maximum Balance
[redacted]				

[End Confidential]

This table demonstrates that even though it may have been more difficult during the peak of the credit market crisis, PSE&G was always able to access the commercial paper market to raise short-term funds.

As of December 31, 2009, PSE&G had no debt outstanding on the credit facility.

PSEG also has a separate credit facility available to it totaling $1 billion as of September 30, 2010. This can be used by the parent to supports its subsidiaries' liquidity needs.[51] However, according to the company, "there is no usage of the PSEG credit facility by PSE&G."[52]

[51] PSEG September 30, 2009 Form 10-Q (p. 77).

As mentioned previously, PSE&G does not engage in any borrowing or lending of money with its affiliates.

Rate Filings

On May 29, 2009, PSE&G filed its request with the NJBPU for an increase in electric and gas base rates. The request called for a $134 million or 1.93% increase in electric distribution revenues and a $96.92 million or 2.95% increase in gas distribution revenues.[53]

The aforementioned filing also contained other requests. These are outlined below:[54]

- A requested ROE of 11.5% to reflect current financial market conditions;
- Establishment of a Pension Expense Tracker to minimize financial risk and buffer significant customer rate impacts
- Establishment of a Gas Weather Normalization Clause to maintain rate stability;
- Expansion of the Capital Economic Stimulus Infrastructure Investment (CESI) Program;
- Changes and Updates to the Cost of Service and Rate Design.

The company's reasoning for the proposed Pension Expense Tracker was incorporated in Mark Kahrer's testimony. Mr. Kahrer at the time was the Vice President – Finance for PSE&G. According to his testimony, the pension expense, per the actuarial report, rose from $8.3 million in 2008 to $73.7 million in 2009.[55] PSE&G estimates that the annual pension expense for 2010 will increase to approximately $82 million. The substantial rise in pension costs is due to the decline in asset values in the pension portfolio. PSE&G is proposing to implement rate adjustments in the capital adjustment charge (CAC) to ensure proper cost recovery to enable the utility to adequately fund the pension plan. The adjustment to the CAC would be made annually, similar to how the base distribution rates are adjusted. Any difference between the actual pension expense and the amount designated for pension expense in the CAC would be deferred each month and included in a CAC over/(under) recovered account balance. The first impact to the CAC would be January 1, 2012 if this proposal was implemented.[56]

The petition also proposed a Gas Weather Normalization Charge. This charge would be based on a calculation that would determine the level by which the billed Margin Revenues differed from what would have resulted if normal weather occurred. Margin revenues are distribution revenues less the Transitional Energy Facility Agreement (TEFA) and Sales and Use Tax (SUT). Any deficiency or excess from the Winter Period would be recovered in the subsequent Winter Period through the proposed Weather Normalization Charge.

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[52] Response to Discovery, OC-977.

[53] Response to Discovery, OC-135.

[54] Response to Discovery, OC-135, PSE&G's Petition for Approval of Increase in Electric and Gas Rates.

[55] Overland Consulting verified this total by finding the 2009 Plan year quarterly required contributions for each of the three PSEG pension plans (FAP, CBP and CBM) found in the response to discovery OC-778. Overland found the result to yield $74.6 million, the difference being immaterial to this discussion.

[56] Response to Discovery, OC-135 Mark Kahrer's testimony in the PSE&G 2009 Rate Case Proceedings.

The petition also called for an expansion of the Capital Economic Stimulus Infrastructure Investment Program. PSE&G proposed new CACs through December 31, 2010 that will reflect the annual revenue requirements associated with eligible capital expenditures from April 28, 2009 through December 31, 2010. Capital expenditures that are eligible for recovery through the new CACs are those that are not related to providing service to new business.

On June 7, 2010, the New Jersey BPU reached a decision on the electric rate case submitted in May 2009. Pursuant to a stipulation executed by the company and various parties, the Board granted PSE&G a total increase of $73.5 million for the next two years. This rate increase was coupled with an order to repay $122 million to rate-paying customers to resolve an issue with the Market Transition Charge. After factoring in the refund, the average residential customer will only pay $1 more per year for the next two years.[57]

On July 9, 2010, the New Jersey BPU rendered a decision on the aforementioned May 2009 gas delivery rate case which was largely based on a stipulation executed between interested parties.[58] The state regulators approved a 0.9% increase in the gas delivery base rate as well as an approximate 5% decrease in the gas supply charges billed to residential customers. The gas delivery base rate increase will amount to a total of $26.5 million increase to gas delivery base revenue.[59] Both S&P and Moody's viewed the rate case outcomes favorably.[60]

A Gas Weatherization Normalization Clause was approved for implementation. However, PSE&G withdrew its requests for a Pension Expense Tracker and an expanded Infrastructure Program.[61]

Leveraged Leases

PSEG Resources LLC, which is a wholly-owned subsidiary of PSEG Energy Holdings LLC, has entered into several leveraged leases. The purpose of these leases is to take advantage of tax-related deductions by taking ownership of certain assets (mostly foreign in nature) and leasing them back to the asset user. The IRS has issued audit reports of PSEG's corporate income tax return, disallowing all of the deductions from 1997 to 2003 and imposing a 20% penalty for the underpayment of taxes related to these leases. PSEG has formally protested the IRS's position on the matter **[Begin Confidential]**

[End Confidential]

PSEG has already paid $320 million to the IRS to offset some interest costs relating to the disputed tax liability. The deposit is fully refundable upon PSEG's successful defense of its position in this matter. This reduces the potential cash exposure from $660 million to $340 million. If PSEG were to concede all

[57] PSE&G Press Release June 7, 2010.
[58] Response to Discovery, OC-1054.
[59] PSE&G Press Release June 18, 2010.
[60] Interview with Caroline Dorsa, Chief Financial Officer, October 19, 2010.
[61] Response to Discovery, OC-1054.
[62] PSEG 2009 10-K and Response to Discovery, OC-44.

of the deductions taken through December 31, 2009, the amount it would be required to pay to the IRS could total over $1 billion, including the deposits already made with the IRS.[63]

PSEG also took an impairment charge in the second quarter of 2008 related to these leases due to the change in projected cash flows. The charge that PSEG took was $485 million before tax and $355 million after tax. PSEG believes that if it were unable to successfully defend its position in the matter, it would have to record an additional impairment charge of $100 to $120 million.[64]

During 2009, PSEG sold its interests in 14 leveraged leases, 12 whose prior years' deductions had been disallowed by the IRS. Proceeds from the sales were $830 million and the after-tax gain was $70 million. Proceeds from the sales of interests in the leveraged leases are being used to reduce the tax exposure related to the leveraged lease investments. As of December 31, 2009, PSEG's total gross investment in its remaining leverage lease interests was $347 million. PSEG is continuing to seek out opportunities to divest the remaining leveraged lease interests that it currently holds.[65]

[63] Overland arrived at this total by taking the upper limits of the tax, interest, and penalties for the tax years 1997-2003 plus the deposit already made to the IRS. See PSEG 2009 10-K.
[64] PSEG 2009 Q3 10-Q.
[65] PSEG 2009 10-K.

Financial Statement Presentation

PSEG's consolidated balance sheets, income statements, and statements of cash flows for 2008 and 2009 follow. We present the same information for PSE&G. We have included these for presentation purposes only.[66]

PSEG

Table 10-14 – PSEG - Consolidated Balance Sheets - Assets

Public Service Enterprise Group Incorporated Consolidated Balance Sheets December 31, 2009 and 2008 (In millions)		
Assets	**2009**	**2008**
Current assets:		
Cash and cash equivalents	$ 350	321
Accounts Receivable, net of allowances of $79 and $66 in 2009 and 2008, respectively	1,229	1,398
Unbilled Revenues	411	454
Fuel	806	938
Materials and Supplies, net	361	317
Prepayments	161	150
Restricted Funds	2	118
Derivative Contracts	243	237
Other	83	66
Total current assets	3,646	3,999
Property, plant, and equipment	22,069	20,818
Less accumulated depreciation and amortization	(6,629)	(6,385)
Net property, plant, and equipment	15,440	14,433
Noncurrent assets		
Regulatory Assets	5,769	6,352
Long-term investments	2,032	2,695
Nuclear Decommissioning Trust (NDT) Funds	1,199	970
Other Special Funds	149	133
Goodwill	16	16
Other Intangibles	123	53
Derivative Contracts	123	160
Other	233	238
Total Noncurrent Assets	9,644	10,617
Total assets	$ 28,730	29,049

See accompanying notes to consolidated financial statements.

ˆ The balance sheet generally would be presented on one page and the heading of the balance sheet would be centered on the page. This balance sheet is presented on two pages to facilitate printing.
˘ Rule 5-02.6(a) of Regulation S-X requires that the major classes of inventory be stated separately in the balance sheet or in the notes to the financial statements for SEC filings. Disclosure of the major classes of inventory is encouraged, but not required, for non-public entities.

[66] The financial statements are from the PSEG 2009 10-K.

Table 10-15 – PSEG - Consolidated Balance Sheets – Liabilities and Stockholders' Equity

Public Service Enterprise Group Incorporated Consolidated Balance Sheets December 31, 2009 and 2008 (In millions)		
Liabilities and Stockholders' Equity	**2009**	**2008**
Current liabilities:		
Long-term Debt Due Within One Year	$ 521	1,033
Commercial Paper	530	19
Accounts Payable	1,081	1,227
Derivative Contracts	201	356
Accrued interest	102	99
Accrued Taxes	90	8
Clean Energy Program	166	142
Obligation to return cash collateral	95	102
Other	428	424
Total current liabilities	3,214	3,410
Noncurrent liabilities:		
Deferred Income Taxes and Investment Tax Credits (ITC)	4,139	3,865
Regulatory Liabilities	404	355
Asset Retirement Obligations	439	576
Other Postretirement Benefit (OPEB) Costs	1,095	975
Accrued Pension Costs	1,094	1,196
Clean Energy Program	400	532
Environmental Costs	704	743
Derivative Contracts	40	164
Long-term Accrued Taxes	538	1,241
Other	140	125
Total liabilities	8,993	9,772
Capitalization		
Long-term Debt		
Long-term debt	6,481	6,621
Securitization Debt	1,145	1,342
Project level, non-recourse debt	19	42
Total long-term debt	7,645	8,005
Subsidiary's preferred stock without mandatory redemption	80	80
Stockholders equity (notes 13 and 15):		
Common stock, no par. Authorized 1,000,000,000 shares;		
issued and outstanding 533,556,600 shares in 2009 and 2008	4,788	4,756
Retained earnings	4,704	3,773
Accumulated other comprehensive loss	(116)	(581)
Treasury stock, X,XXX and X,XXX common shares		
in 2007 and 2006, respectively, at cost	(588)	(177)
Total common stockholders' equity	8,788	7,771
Noncontrolling interest	10	11
Total stockholders equity	8,798	7,782
Total Capitalization	16,523	15,867
Total liabilities and stockholders equity	$ 28,730	29,049

See accompanying notes to consolidated financial statements.

C The balance sheet generally would be presented on one page and the heading of the balance sheet would be centered on the page. This balance sheet is presented on two pages to facilitate printing.

D The balances of each classification within accumulated other comprehensive income can be displayed in a note to the consolidated financial statements. See note 14.

Table 10-16 – PSEG - Consolidated Statements of Income

Public Service Enterprise Group Incorporated
Consolidated Statements of Income
Years ended December 31, 2009, 2008, and 2007
(In millions)

	2009	2008
Operating Revenues	$12,406	$13,322
Operating Expenses		
Energy Costs	5,711	7,295
Operation and Maintenance	2,603	2,486
Depreciation and Amortization	838	792
Taxes Other Than Income Taxes	133	136
Total Operating Expenses	9,285	10,709
Operating Income	3,121	2,613
Income from Equity Method Investments	39	37
Gain (Loss) on Disposal and (Impairment) on Equity Method in Investments	(22)	(27)
Other income	247	436
Other deductions	(161)	(336)
Other-than-temporary Impairments	(61)	(220)
Interest expense	(527)	(594)
Income from Continuing Operations Before Income Taxes	2,636	1,909
Income taxes	(1,044)	(926)
Income from Continuing Operations	1,592	983
Income (Loss) from Discontinued Operations, including Gain (Loss) on Disposal, net of tax expense of $171 and $157 for the years ended 2008 and 2007, respectively	0	205
Net Income	$1,592	$1,188

[E] If any year presented shows a net loss, the statements should be retitled "Consolidated Statements of Operations." If other comprehensive income is included, the statements should be retitled "Consolidated Statements of Income and Comprehensive Income."

Table 10-17 – PSEG - Consolidated Statements of Cash Flows

Public Service Enterprise Group Incorporated Consolidated Statements of Cash Flows Years ended December 31, 2009 and 2008 (In millions)	2009	2008
Cash flows provided by operating activities:		
Net income	$1,592	$1,188
Discontinued operations, net of tax	—	(335)
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	838	793
Gain on sale of investments	(167)	(11)
Undistributed earnings from affiliates	(28)	(40)
Provision for Deferred income tax expense (other than leases) and ITC	326	71
Non-cash employee benefit costs	347	167
Net change in certain current assets and liabilities	221	74
Amortization of Nuclear Fuel	121	101
Lease Transaction Reserves, net of tax	(29)	490
Leveraged Lease Income, Adjusted for Rents Received and Deferred Taxes	(678)	51
(Gain) loss on disposal and impairment on equity method investments	22	27
Realized and unrealized (gains) losses on energy contracts and other derivatives	25	(39)
Under recovery of electric energy costs (BGS and NTC) and gas costs	(32)	(43)
Over (Under) recovery of societal benefits charge (SBC)	4	(75)
Cost of removal	(54)	(44)
Net realized (gains) losses and (income) expense from NDT funds	(50)	115
Employee benefit plan funding and related payments	(446)	(139)
Other	(157)	(6)
Cash provided by operating activities	1,855	2,345
Cash flows from investing activities:		
Additions to property, plant, and equipment	(1,794)	(1,771)
Settlement for Spent Nuclear Fuel Claim	47	—
Proceeds from sale of investments and capital leases	880	77
Proceeds from sale of discontinued operations	—	925
Proceeds from NDT funds sales	1,769	3,060
Investment in NDT funds	(1,798)	(3,093)
Proceeds from sale of property, plant, and equipment	2	9
Restricted Funds	116	(11)
NDT funds interest and dividends	39	48
Solar loan investments	(43)	—
Other	(10)	(19)
Net cash used in investing activities	(792)	(775)
Cash flows from financing activities:		
Net change in commercial paper and loans	511	(46)
Issuance of long-term debt	459	1,075
Issuance of non-recourse debt	—	—
Issuance of common stock	—	—
Redemption of long-term debt	(820)	(1,582)
Repayment of non-recourse debt	(286)	(56)
Payments to acquire treasury stock	—	(92)
Redemption of securitization debt	(187)	(179)
Net premium paid on early extinguishment of debt	—	(79)
Premium paid on debt exchange	(36)	—
Redemption of debt underlying trust securities	—	—
Dividends paid	(673)	(655)
Other	(2)	(15)
Net cash provided by financing activities	(1,034)	(1,629)
Net increase (decrease) in cash and cash equivalents	29	(59)
Cash and cash equivalents at beginning of year	321	380
Cash and cash equivalents at end of year	$350	$321

PSE&G

Table 10-18 – PSE&G - Consolidated Balance Sheets

Public Service Electric and Gas Company

Consolidated Balance Sheets

December 31, 2009 and 2008

(In millions)

Assets	2009	2008
Current assets:		
Cash and cash equivalents	$240	$91
Accounts Receivable, net of allowances of $78 and $65 in 2009 and 2008, respectively	800	909
Unbilled Revenues	411	454
Materials and Supplies, net	70	61
Prepayments	86	45
Deferred income taxes	52	52
Other	3	1
Total current assets	1,662	1,613
Property, plant, and equipment	12,933	12,258
Less accumulated depreciation and amortization	(4,187)	(4,122)
Net property, plant, and equipment	8,746	8,136
Noncurrent assets		
Regulatory Assets	5,769	6,352
Long-term investments	204	158
Other Special Funds	51	46
Other	101	101
Total Noncurrent Assets	6,125	6,657
Total assets	16,533	16,406

See accompanying notes to consolidated financial statements.

[A] The balance sheet generally would be presented on one page and the heading of the balance sheet would be centered on the page. This balance sheet is presented on two pages to facilitate printing.

[B] Rule 5-02.6(a) of Regulation S-X requires that the major classes of inventory be stated separately in the balance sheet or in the notes to the financial statements for SEC filings. Disclosure of the major classes of inventory is encouraged, but not required, for non-public entities.

Table 10-19 – PSE&G – Consolidated Balance Sheets

Public Service Electric and Gas Company
Consolidated Balance Sheets
December 31, 2009 and 2008
(In millions)

Liabilities and Stockholders' Equity	2009	2008
Current liabilities:		
Long-term Debt Due Within One Year	$498	$248
Commercial Paper	—	19
Accounts Payable	337	336
Accounts Payable - Affiliated Companies, net	496	763
Accrued interest	56	58
Accrued Taxes	4	3
Clean Energy Program	166	142
Derivative Contracts	—	14
Obligation to return cash collateral	95	102
Other	210	227
Total current liabilities	1,862	1,912
Noncurrent liabilities:		
Deferred Income Taxes and Investment Tax Credits (ITC)	2,710	2,533
Other Postretirement Benefit (OPEB) Costs	887	813
Accrued Pension Costs	565	634
Regulatory Liabilities	404	355
Clean Energy Program	400	532
Environmental Costs	652	689
Asset Retirement Obligations	211	240
Derivative Contracts	—	53
Long-term Accrued Taxes	96	82
Other	29	31
Total liabilities	5,954	5,962
Capitalization		
Long-term Debt		
Long-term debt	3,271	3,463
Securitization Debt	1,145	1,342
Total long-term debt	4,416	4,805
Subsidiary's preferred stock without mandatory redemption	80	80
Stockholders equity (notes 13 and 15):		
Common stock, no par. Authorized 1,000,000,000 shares; issued and outstanding 533,556,600 shares in 2009 and 2008	892	892
Contributed Capital	420	170
Basis Adjustment	986	986
Retained earnings	1,918	1,597
Accumulated other comprehensive loss	5	2
Total stockholders equity	4,221	3,647
Total Capitalization	8,717	8,532
Total liabilities and stockholders equity	16,533	16,406

See accompanying notes to consolidated financial statements.

` The balance sheet generally would be presented on one page and the heading of the balance sheet would be centered on the page. This balance sheet is presented on two pages to facilitate printing.

ᵇ The balances of each classification within accumulated other comprehensive income can be displayed in a note to the consolidated financial statements. See note 14.

Table 10-20 – PSE&G Consolidated Statements of Income

Public Service Electric and Gas Company Consolidated Statements of Income Years ended December 31, 2009, 2008, and 2007 (in millions)		
	2009	2008
Operating Revenues	$8,243	$9,038
Operating Expenses		
Energy Costs	5,170	6,072
Operation and Maintenance	1,474	1,338
Depreciation and Amortization	608	583
Taxes Other Than Income Taxes	133	136
Total Operating Expenses	7,385	8,129
Operating Income	858	909
Other income	8	12
Other deductions	(3)	(4)
Interest expense (note 1(v))	(312)	(325)
Income from Continuing Operations Before Income Taxes	551	592
Income taxes (note 12)	(226)	(228)
Income from Continuing Operations	325	364
Preferred Stock Dividends	(4)	(4)
Net Income (available to PSEG Inc.)	321	360

See accompanying notes to consolidated financial statements.

E If any year presented show s a net loss, the statements should be retitled “Consolidated Statements of Operations.” If other comprehensive income is included, the statements should be retitled “Consolidated Statements of Income and Comprehensive Income.”

Table 10-21 – Consolidated Statements of Cash Flows

Public Service Electric and Gas Company
Consolidated Statements of Cash Flows
Years ended December 31, 2009 and 2008
(In millions)

	2009	2008
Cash flows provided by operating activities:		
Net income	$325	$364
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	608	583
Gain on sale of property, plant, and equipment	(2)	(1)
Non-cash interest expense	12	15
Provision for Deferred income tax expense (other than leases) and ITC	194	86
Non-cash employee benefit costs	236	129
Net change in certain current assets and liabilities		
Accounts receivable and unbilled revenues	152	(19)
Materials and supplies	(9)	(8)
Prepayments	(41)	12
Accrued Taxes	—	(26)
Accounts payable	1	11
Accounts receivable/payable - affiliated companies, net	(62)	(8)
Obligation to return cash collateral	(7)	23
Other current assets and liabilities	(37)	11
Over (Under) recovery of gas charges	38	(47)
Over (Under) recovery of electric energy costs (BGS and NTC) and gas costs	(70)	4
Over (Under) recovery of societal benefits charge (SBC)	4	(75)
Cost of removal	(54)	(44)
Other non-cash charges	—	(5)
Employee benefit plan funding and related payments	(288)	(108)
Other	(43)	16
Cash provided by operating activities	957	913
Cash flows from investing activities:		
Additions to property, plant, and equipment	(855)	(761)
Solar loan investments	(43)	—
Other	5	—
Net cash used in investing activities	(893)	(761)
Cash flows from financing activities:		
Net change in short term debt	(19)	(46)
Issuance of long-term debt	250	1,075
Contributed capital	250	—
Deferred Issuance Costs	(2)	(6)
Redemption of long-term debt	(203)	(901)
Redemption of securitization debt	(187)	(179)
Premium paid on early retirement of debt	—	(32)
Common stock dividends paid	—	—
Preferred stock dividends	(4)	(4)
Net cash provided by financing activities	85	(93)
Net increase (decrease) in cash and cash equivalents	149	59
Cash and cash equivalents at beginning of year	91	32
Cash and cash equivalents at end of year	240	91

See accompanying notes to consolidated financial statements.

Net cash provided by operating activities may be presented under either the indirect method or the direct method. This example illustrates the indirect method. If the indirect method is used, the reconciliation of net income to net cash provided by operating activities may be either (a) reported within the statement of cash flows or (b) provided in the notes to the financial statements.

This example statements of cash flows is presented for illustrative purposes and includes presentation of cash flows of discontinued operations. It is not related to the *basic example* and, therefore, the captions are different and footnotes and related disclosures are not presented, where presentations and disclosures for discontinued operations were included.

Performance Measurement

PSEG uses a balanced scorecard to track the performance of the Finance departments of both the utility and the enterprise. The Enterprise Finance division scorecard consists of all of the departments that report to the CFO, which are: Accounting Services, Risk Management, Internal Audit, Investor Relations, and Treasury.

PSE&G

[Begin Confidential] Table 10-22 – PSE&G Finance Balanced Scorecard

PSE&G Finance Balanced Scorecard			
Metrics	2009 Benchmark	2008	2009
[redacted]			

[End Confidential]

As shown above, there are a few metrics whose target was not met in 2009. The metrics that were not met are described below:

- Overland noted that Cash from Operations did not reach its benchmark for 2009. Ms. Dorsa said in her interview that the main reason this objective was not achieved was due to higher than expected commodity prices.
- The Capital Project Results metric also was not achieved in 2009. This metric evaluates the effectiveness of how well a project performed by looking at costs, schedule, and operational benefits when initially presented for funding as well as how the project was then executed.
- PSE&G's ROIC (Return on Invested Capital) metric was not met during 2009. This metric is described as the net income earned before interest divided by business unit capitalization.

11. Rates and Regulation

This Chapter addresses PSE&G's regulatory activities as well as information relating to customer rates for gas and electric transmission and distribution. PSE&G also employs a number of cost recovery mechanisms that are designed to operate in conjunction with but independent of the typical ratemaking process, which is driven by revenue requirements derived from a base rate case. Most of these are discussed in this chapter.

Annual gains and revenues not derived from PSE&G utility rates have ranged from $9,898,000 to $27,309,000 during the time period from 2004 to 2009. This represents, on average, less than 5% of PSE&G's net income over this six-year period and 0.21% of total operating revenues. Non-rate related revenues are discussed in the last section of this chapter.

Summary of Findings

1. The organization of the regulatory function of PSE&G has changed materially with the departure of Fran Sundheim, whose position was Vice President – Corporate Rate Counsel. In general, Ms. Sundheim's direct reports that related to the finance functions in the Regulatory group were moved to the utility finance function led by Rose Chernick, Vice President – Finance, PSE&G. Ms. Sundheim's direct reports that related to the legal function of the Regulatory group were absorbed by Tamara Linde, Vice President - Regulatory.

2. PSE&G customers (residential, commercial and industrial) appear to have very competitive rates when compared to utility companies in the surrounding area.

3. PSE&G was awarded a $100 million increase in electric and gas distribution rates during the summer of 2010. This provides the utility with a return on equity of 10.3%. Although, the increase did not meet the internal expectations of the utility, the credit analysts believed PSE&G received fair treatment in the rate case proceeding and do not view the outcome negatively with respect to the financial position of the utility.

4. The Morris Energy Case, a supplemental proceeding to the 2009 gas rate case, concerning issues relating to the charges for transmitting natural gas for certain generating companies was settled on December 8, 2010 and the settlement was approved by the NJBPU on December 22, 2010.

5. PSE&G has been permitted by the New Jersey BPU to recover the costs of certain programs outside the context of base rate case proceedings. Examples of these programs include, but are not limited to, those that encourage energy efficiency, investment in renewable energy, and economic stimulus in the state of New Jersey.

6. The orders approving these programs use broad language to define the costs that can be recovered in rate adjustment clauses. As disclosed by the company, we observed no costs charged to these programs that fell outside the general parameters of these definitions.

However, the company only provided details of its costs for one month, and we did not independently verify the classification of such costs.

7. The company asserts that it has not deferred any prior year costs since the beginning of 2008 in any of its cost recovery mechanisms. This was a point of contention between the company and other parties in the past. Overland did not independently test the validity of this assertion.

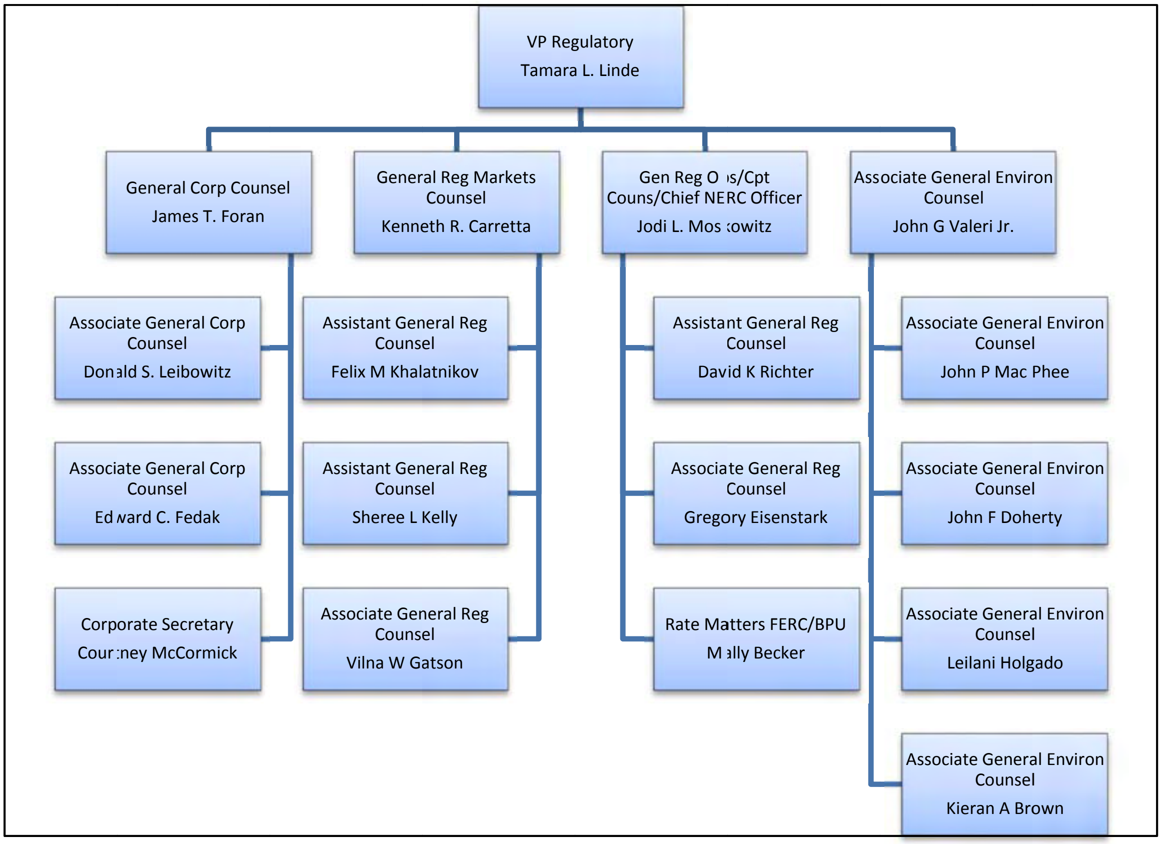
8. The most significant non-rate related revenues in recent years are associated with tax gross-ups on contributions in aid of construction, the offset to amortization of Repair Allowance & Restructuring required by the 2003 rate order, and gains and losses on sales of property.

9. In its most recent electric and gas rate filings, PSE&G proposed to share one-half of gains on the sale of property with ratepayers using a five-year average. The requests for rate increases were ultimately resolved in a settlement which was silent on the matter of the sharing of these gains.

Regulatory Organization

The legal function of the PSE&G Corporate Rate Counsel (CRC) department was shifted to a new rates group within the PSEG Law Department's regulatory group headed by Tamara Linde, VP-Regulatory. The CRC department had been led by Fran Sundheim, VP-Corporate Rate Counsel, who left PSEG. The financial regulatory function of the CRC department was merged with that of Utility Finance led by Rose Chernick, VP Finance – PSE&G after the departure of Fran Sundheim. Below is an organizational chart for the Regulatory function of PSE&G.

Table 11-1 – Regulatory Organization Chart



Source: Response to OC-1270, p. 43

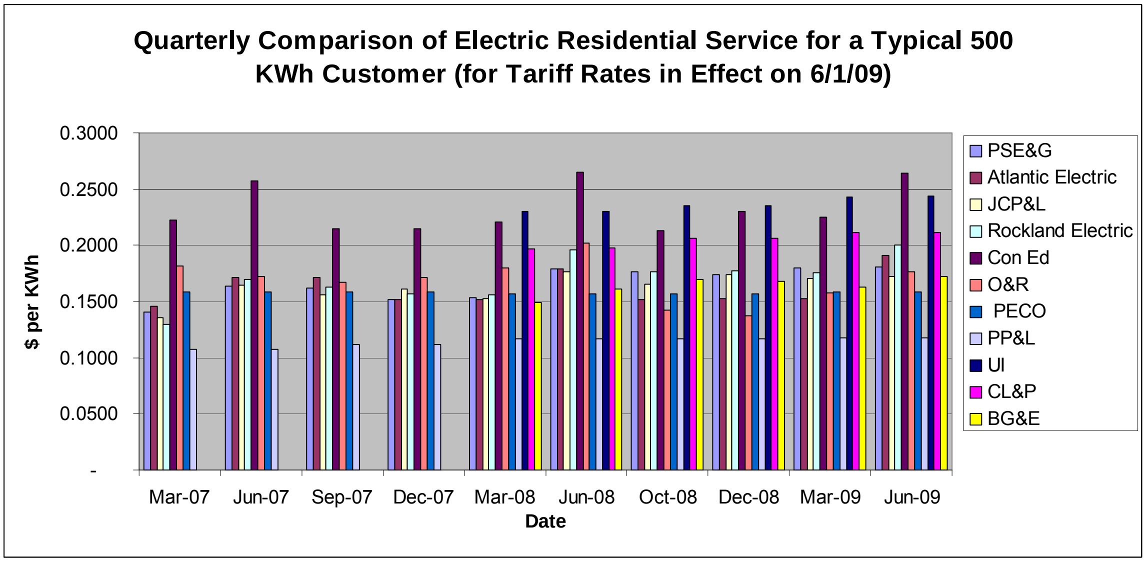
There are also some PSEG Service Company employees that report to Rose Chernick, who is the Vice President of Finance for PSE&G.[1] These employees' titles are: Director of Rates & Regulations, Revenue Requirements Manager and Director of Regulatory Research and Analysis. These employees previously reported to Fran Sundheim before her departure from PSEG.[2]

Electric Rates

PSE&G's residential customers incur very competitive rates when compared to other electric utility companies in New Jersey and surrounding area. Below is a graph showing the comparison of the amount billed per KWh based on a 500 KWh electric bill.

[1] Ibid.
[2] Response to Discovery OC-1379.

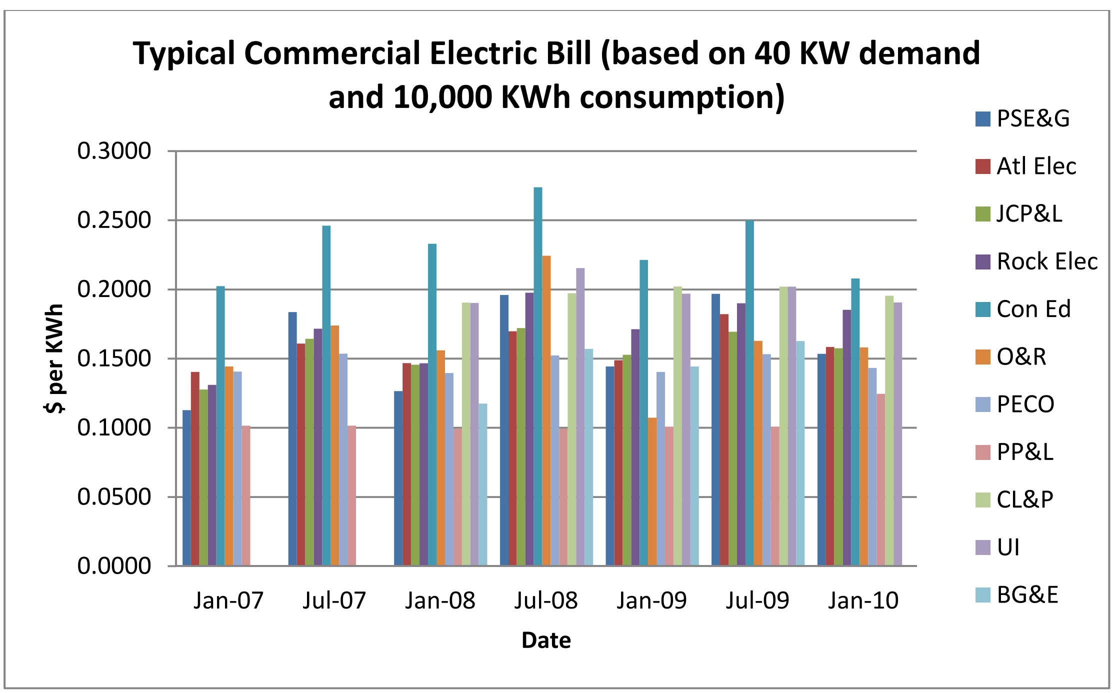
Table 11-2 – Quarterly Comparison of Electric Residential Service



Source: Derived from response to OC-121

PSE&G's commercial customers also experience competitive rates when compared to other electric utility companies in New Jersey and the surrounding area. Below is a graph showing the comparison of the amount billed per KWh based on 40 KW demand and 10,000 KWh consumption.

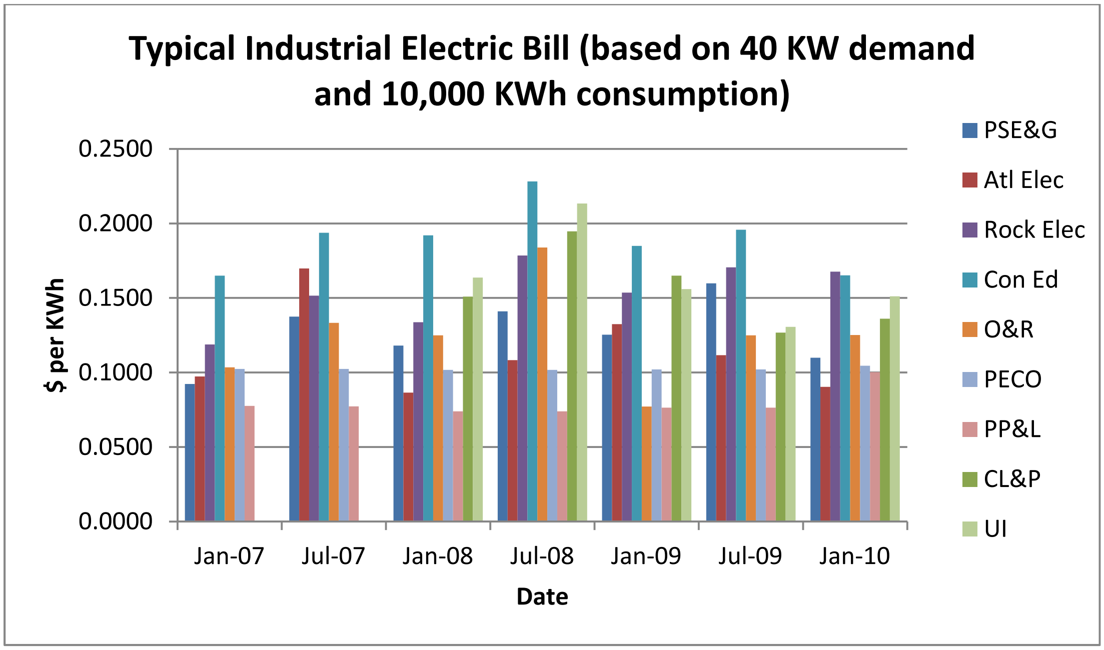
Table 11-3 – Typical Commercial Electric Bill



Source: Derived from response to OC-1045. PSE&G obtained the data for the chart from Edison Electric Institute (EEI)

PSE&G's industrial customers also receive very competitive rates when compared to other electric utility companies in New Jersey and the surrounding area. Below is a graph showing the comparison of the amount billed per KWh based on 1,000 KW demand and 400,000 KWh consumption.

Table 11-4 – Typical Industrial Electric Bill

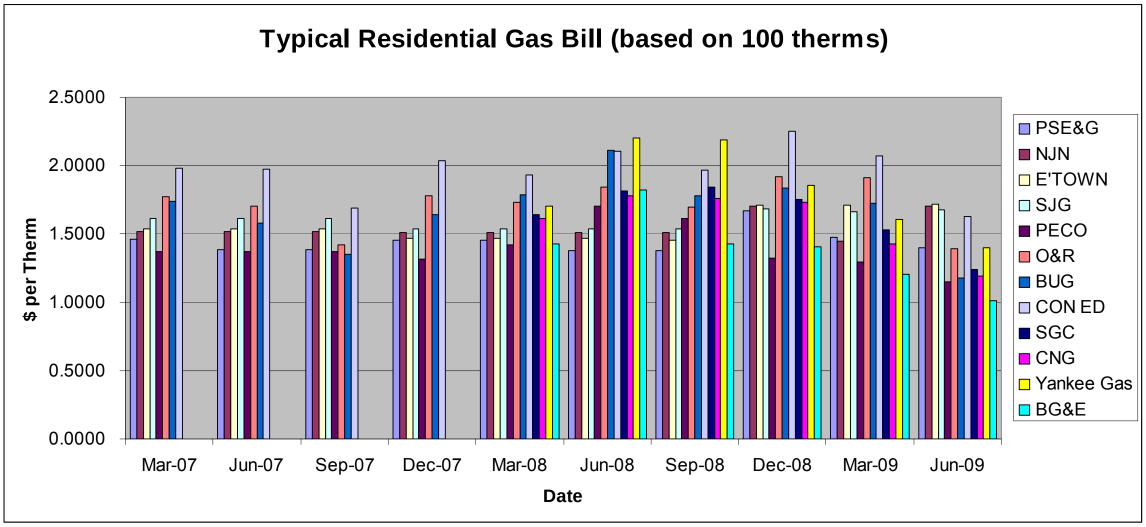


Source: Derived from response to OC-1045. PSE&G obtained the data for the chart from Edison Electric Institute (EEI)

Gas Rates

PSE&G residents enjoy competitive gas rates as shown below in the chart when compared to other gas utilities in New Jersey and the surrounding area. In fact, in a couple of months, June and September 2008, PSE&G is the cheapest gas on a per therm basis. Below is a graph that shows how much each utility's residential customer pays per therm of gas.

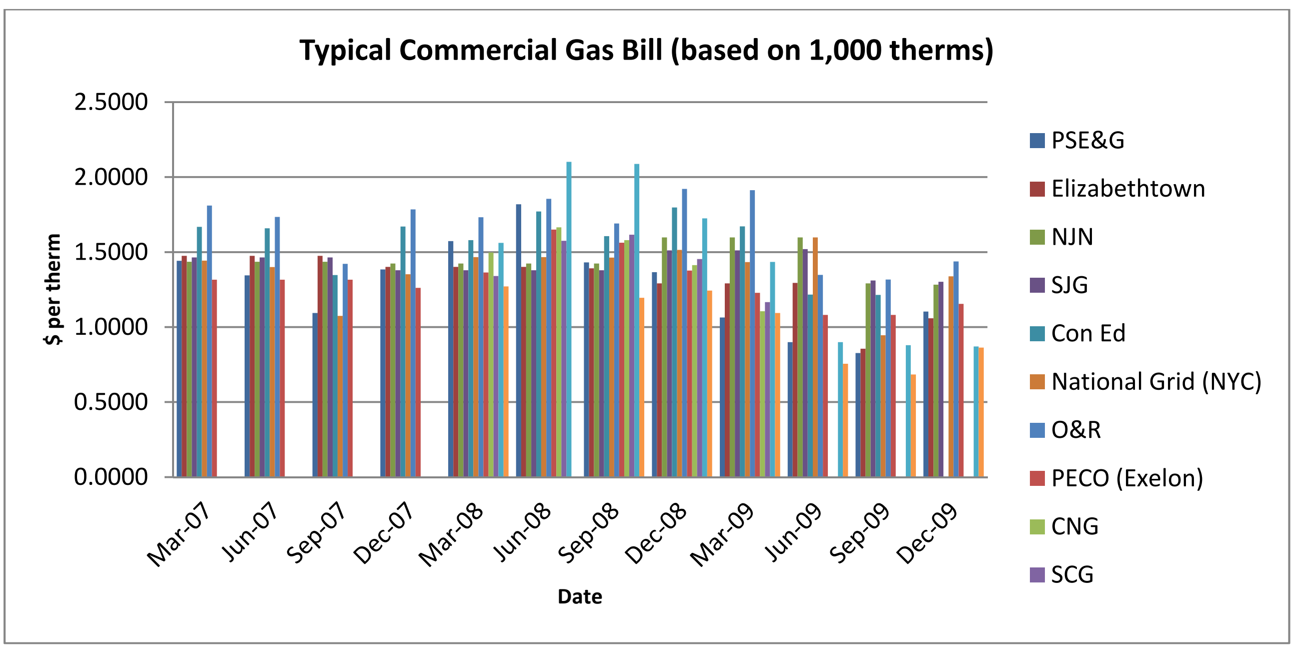
Table 11-5 – Typical Residential Gas Bill



Source: Derived from response to OC-121

PSE&G's commercial customer rates are also competitive when compared to other gas utility companies in New Jersey and the surrounding area. In March 2009, PSE&G customer enjoyed the lowest per therm gas rates of all of it peers in the area. Below is a graph showing the comparison of the amount billed per therm based on the consumption of 1,000 therms.

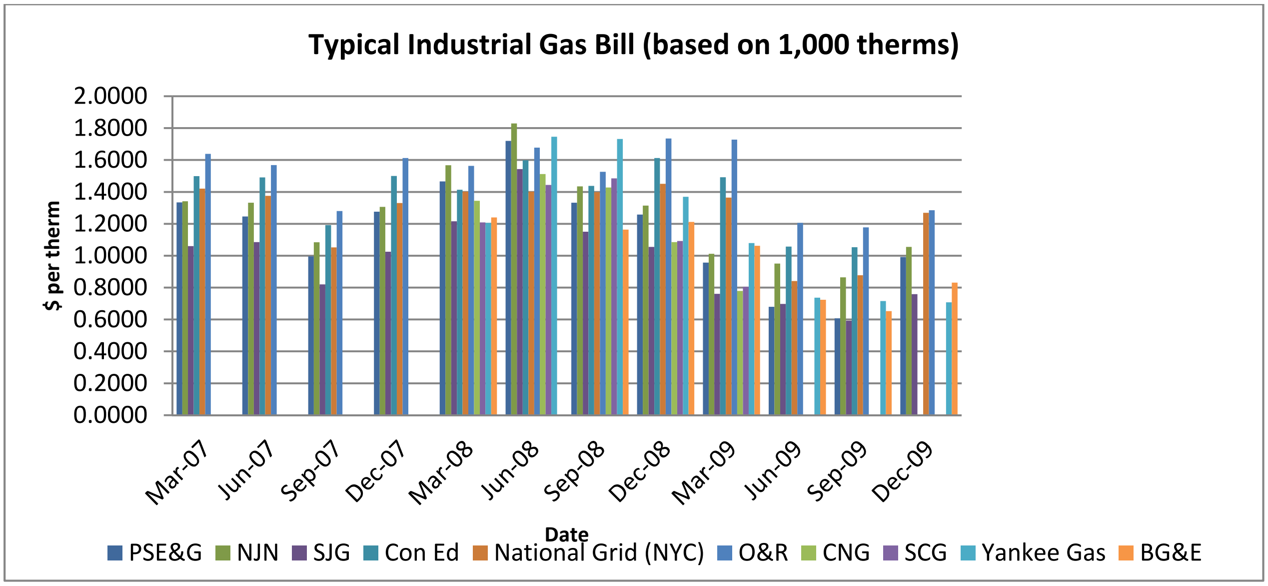
Table 11-6 – Typical Commercial Gas Bill



Source: Derived from response to OC-1045. PSE&G obtained the data for the chart from Edison Electric Institute (EEI)

The gas rates for PSE&G's industrial customers are competitive as well. As seen in the chart below, PSE&G is consistently around the middle of the peer group with respect to the price per therm based on a 1,000 therm gas bill.

Table 11-7 – Typical Industrial Gas Bill



Source: Derived from response to OC-1045. PSE&G obtained the data for the chart from Edison Electric Institute (EEI)

Rate Case Filings

On May 29, 2009, PSE&G filed with the New Jersey Board of Public Utilities for a rate base increase for electric and gas to support the company's infrastructure and maintain customer support. The amounts that PSE&G sought in the rate case increase were: $133.7M for electric, a 1.93% increase to the base rates as of the filing date and $96.9M for gas, a 2.95% increase to the base rates as of the filing date.[3]

In June 2010, the stipulations were executed on the electric and gas base rate cases. On June 7, 2010, the New Jersey Board of Public Utilities announced that PSE&G would receive a $73.5 million increase in electric distribution rates.[4] Soon after, on June 18, 2010, the BPU approved a $26.5 million increase in gas distribution base rate, which represented a 0.9% increase to the previous rate.[5] The allowed return on equity in from the electric and gas rate case settlement was set at 10.3%.

PSE&G customers did however see some relief in the electric and gas base rate settlements. In the electric rate case settlement, the BPU ordered PSE&G to refund to its customers $122 million in

[3] Response to Discovery OC-120.
[4] PSEG Press Release 6/7/10 "PSE&G's Electric Rates to Change Modestly Under Agreements Approved by New Jersey Board of Public Utilities".
[5] PSEG Press Release 6/18/10 "New Jersey Board of Public Utilities Approves New PSE&G Gas Delivery Rates".

resolution of how an interest methodology should be applied to the Market Transition Charge recovery.[6, 7] In the gas rate case settlement, PSE&G agreed to lower the residential natural gas supply charges by approximately five percent.[8]

Although PSE&G's reaction to the rate settlements was positive in public media, the utility management was disappointed with the outcome of the rate cases. In Overland Consulting's interview with Mark Kahrer, VP of Finance – PSE&G, he disclosed that the settlement fell short of the company's expectation. He pointed specifically to adjustments made to consolidated taxes and incentive compensation that PSE&G did not agree with. Mr. Kahrer also disclosed that the utility didn't believe that it owed any further refund to its customers to resolve the Market Transition Charge described above. Mr. Kahrer stated that the utility will adjust its capital spending programs to be more aligned with the allowed ROE that was settled in the rate case.[9] The Utility's Finance department is currently exploring the need for a future rate case. Some factors they are using in their determination include: having adequate cash flow for capital expenditures to ensure safe and reliable service to their electric and gas customers and the ability to achieve the allowed return on equity from the settled rate case.[10]

Morris Energy Group Order

As a supplemental proceeding to the rate case filing described above, the New Jersey Board of Public Utilities wanted to address the following issues that were raised by the Morris Energy Group and the New Jersey Large Energy Users Coalition (NJLEUC):

1. Whether the continued receipt of interruptible gas transportation service pursuant to a non-tariff rate scheduled by PSEG Power beyond July 31, 2002 was justified and in the public interest;
2. Whether the societal benefits charges (SBC) and RGGI charges should apply to PSEG Power, retroactively and prospectively;
3. Whether the rate applicable to PSEG Power is discriminatory to Morris Energy Group (MEG) and other electric generation customers;

[6] PSEG Press Release 6/7/10 "PSE&G's Electric Rates to Change Modestly Under Agreements Approved by New Jersey Board of Public Utilities".

[7] As part of the restructuring agreement to transfer PSE&G's generating units to PSE&G's unregulated affiliate, PSEG Power, PSE&G received a cash advance of $540 million from PSEG Power toward the recovery of the generating units' stranded costs. This so-called "transfer premium" was to be used to reduce PSE&G's capitalization, and was to be repaid from the revenues collected by PSE&G from (1) its Market Transition Charge (MTC); (2) the amortization of its excess depreciation reserve; and (3) a 2 mill per kWh "retail adder" applied to the Basic Generation Service (BGS). If, at the end of the four-year Transition Period, these three revenue sources were not sufficient to fully repay the $540 million advance, the shortfall was to be absorbed by PSEG Power. If the $540 million were to be over-recovered, the excess revenue recovery was to be refunded to PSE&G's ratepayers by way of credits in the Societal Benefits Charge (SBC).

[8] PSEG Press Release 6/18/10 "New Jersey Board of Public Utilities Approves New PSE&G Gas Delivery Rates".

[9] Interview with Mark Kahrer, July 7, 2010.

[10] Ibid.

4. Whether the Non-Firm Transportation Gas Service (TSG-NF) rate service should be applicable to PSEG Power, MEG and other electric generation customers.[11]

After testimony was filed by all parties in the supplemental proceeding, the case went into settlement negotiations. On December 8, 2010 a settlement was reached by all of the parties involved in the supplemental proceeding. The main points of the settlement are summarized as follows:

1. No retroactive adjustments or refunds would be given by PSE&G for previous rates charged in the gas transportation service described in the scope of the proceeding.
2. The rate charged by PSE&G for the transportation of natural gas in the scope of the proceeding will be 42.5 cents per dekatherm for all parties for three years. The rate for Camden and Newark Bay to transport natural gas through the PSE&G system begins after the expiration of the initial terms of their current contracts.
3. Camden and Newark Bay have the option to opt out of their current contracts.
4. PSE&G will provide a credit of 30 cents per dekatherm to NJLEUC members towards the payment of its charges for gas distribution.
5. An option agreement is approved for MEG to purchase a lateral gas line delivering gas to Camden at a fair market value.

The New Jersey BPU subsequently approved the stipulation of settlement on December 22, 2010.[12]

Cost Recovery Mechanisms

Introduction

The cost recovery mechanisms identified by the company include:[13]

- Energy Efficiency and Renewable Energy Programs
- Social Programs
- Universal Service Fund and Lifeline
- Solar Loan Program I
- Carbon Abatement Program
- Energy Efficiency Economic Stimulus Program
- Solar Generation Investment (Solar 4 All) Program
- Demand Response Programs
- Capital Adjustment Charge

In addition to these, other cost recovery mechanisms employed by PSE&G include those associated with the underlying commodity, non-utility generation charges, and manufactured gas plant remediation. The latter two are specifically discussed elsewhere in this report.

[11] NJ BPU Decision and Order Adopting Stipulation of Settlement (Supplemental Proceeding): Docket No. GR09050422.
[12] Ibid.
[13] Response to Discovery, OC-48 and review of current PSE&G tariffs posted on the company website.

In response to a request for the monthly costs by expense type for each cost recovery mechanism over a two-year period (December 31, 2007 to December 31, 2009), the company provided details of costs for only one month.[14] In some cases, the details for this one month could be reconciled to the deferred account roll-forward provided for the applicable cost recovery mechanism. However, in other cases, such an exercise was unsuccessful.[15] Time constraints did not permit us to resolve these outstanding issues.

According to the company, direct charging is the predominate method in assigning costs to these cost recovery mechanisms.[16] The evaluation of the company's cost allocation procedures is addressed elsewhere in this report.

A short summary of each cost recovery mechanism follows.

Energy Efficiency and Renewable Energy Programs

These programs are collected through PSE&G's Societal Benefits Charge (SBC) which is designed to insure recovery of costs associated with activities that are required to be accomplished to achieve specific public policy government mandates.

According to the company's tariffs, costs segregated for these programs include core and performance program costs, performance program payments, payments for large-scale conservation investments, and costs for all New Jersey Clean Energy Program energy efficiency and renewable energy programs (formerly known as Comprehensive Resource Analysis programs).[17]

As disclosed by the company, the costs associated with this program in October 2009 included outside contractors, marketing, sales, training, incentive payments, information technology, and administration costs among others.[18]

Program costs are initially deferred and directly offset by amounts billed at tariffed rates.[19]

The recovery of these types of costs was the subject of dispute between PSE&G and the Department of the Public Advocate, Division of Rate Counsel and BPU Staff in the company's 2007 annual SBC filing. The controversy was centered on whether or not PSE&G should be permitted recovery of certain costs associated with these programs that had been incurred in prior years – a time period that had previously

[14] Response to Discovery, OC-991.
[15] Comparison of Responses to Discovery, OC-48 and OC-991.
[16] Response to Discovery, OC-48.
[17] Current PSE&G tariffs posted on the company website.
[18] Response to Discovery, OC-991.
[19] Responses to Discovery, OC-48 and OC-991.

been the subject of a settlement. The BPU ultimately ruled that this settlement precluded PSE&G from recovering costs incurred in prior years and disallowed approximately $1.4 million.[20]

Company management states that it has not deferred prior year costs for any of the cost recovery mechanisms it identified above since January 1, 2008, including the Energy Efficiency and Renewable Energy Programs.[21] However, we did not independently verify this representation.

Social Programs

Social Programs is also a component of the SBC. During the time period from 2008 to present, it consisted solely of costs associated with uncollectible electric customer accounts. However, it is not limited to these types of costs.[22]

The activity recorded to the deferred account is the difference between the current month's bad debt accrual and tariffed rates. Bad debt accruals, in turn, are a function of net write-offs supplemented by a determination of reserve adequacy.[23]

Universal Service Fund and Lifeline[24]

The New Jersey BPU created the Universal Service Fund (USF) to help make energy bills more affordable for low-income customers. The goal of the program is to cap annual spending on natural gas and electric service by income-eligible New Jersey customers at 6 percent of annual income. Funds are designed to be collected from customers of electric and natural gas utilities operating in the state on a uniform basis.

Lifeline is a program administered by the New Jersey Department of Health and Senior Services that provides a $225 benefit to seniors and the disabled who meet certain eligibility requirements. Funding of the program is similar to that of the USF. Both the USF and Lifeline are components of the SBC.

Costs of the programs primarily consist of bill credits applied to eligible customers' accounts. The BPU also authorized the company to initially "defer on its books and records all of the costs associated with the provision of the interim USF program."[25] Administrative costs were capped at 10 percent.[26] Cash received from the state trust (which is funded by collections from the general population of utility

[20] Decision and Order concerning BPU Docket Nos. ER07050303 and GR07050304 dated December 8, 2008 (Response to Discovery, OC-48 (Attachment A1)).

[21] Response to Discovery, OC-615.

[22] Response to Discovery, OC-48 and current PSE&G tariffs posted on the company website.

[23] Response to Discovery, OC-48.

[24] New Jersey BPU website and Order Approving Interim USF Rates and Lifeline Rates in Docket No. EO09060506 dated October 8, 2009 (Response to Discovery, OC-48 (Attachment A2)).

[25] Universal Service Fund Order in Docket No. EX00020091 dated April 1, 2002 (Response to Discovery, OC-48 Supplemental).

[26] Universal Service Fund Revised Order Approving New USF Program Year Rates and New Lifeline Rates in Docket No. EX00020091 dated June 30, 2004 (Response to Discovery, OC-48 Supplemental).

customers) offsets these costs. Amounts collected from other customers are remitted to the state and have no effect on net income.[27]

Administrative costs disclosed by the company in its June 2009 filing primarily consisted of labor, information technology, and carrying costs.[28]

Solar Loan Program[29]

In April 2008, the BPU issued an order adopting a settlement entered into between PSE&G and various parties concerning a "distributed photovoltaic solar initiative". The proposed program was designed to fulfill approximately one-half (or 30 MW) of the BPU's estimated Renewable Portfolio Standard requirements of 57 MW for load served in PSE&G's service territory during the energy years 2009 and 2010.

Under the program, PSE&G provided loans to developers or customers for a portion of the cost of solar photovoltaic systems. The loans were to be repaid over a ten to fifteen year period in the form of Solar Renewable Energy Certificates[30] or cash. In the first year of the program, loans were to be spread among various market segments, including the Municipal/Non-for-Profit segment, the Residential segment, and the Commercial & Industrial segment.

The net monthly revenue requirements associated with this program would be recovered through a new charge known as the Solar Pilot Recovery Charge. The net revenue requirements would be calculated as follows (from p. 15 of the order):

(Cost of Capital x Net Plant)
Plus: Amortization
Plus: Recoverable Administrative Costs
Minus: Net Proceeds from the sale of Solar Renewable Energy Certificates
Minus: Cash Payments Received in Lieu of Solar Renewable Energy Certificates

The cost of capital for this program was set at 11.11%, which was based on the most recent return on common equity of 9.75% at the time. Net plant was defined as the original loan amounts less the accumulated amortization of principal. PSE&G is permitted to recover 50 percent of the estimated annual administrative costs of the program as set forth in a schedule filed with the BPU as part of the settlement, but in no case exceeding $1 million per year.

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[27] Responses Discovery, OC-48 and OC-991.

[28] Response to Discovery, OC-48 Supplemental.

[29] Decision and Order Approving Settlement in Docket No. EO07040278 dated April 16, 2008 provided in response to Discovery, OC-48 (Attachment A4) unless otherwise noted.

[30] A Solar Renewable Energy Certificate represents the environmental benefits or attributes of one megawatt-hour of solar electric generation (Decision and Order Approving Settlement in Docket No. EO07040278 dated April 16, 2008 provided in response to Discovery, OC-48 (Attachment A4: p. 2).

According to the company, it has incurred administrative labor and outside services costs, costs associated with residential loan discounts, losses on the Solar Renewable Energy Certificates transferred to PSE&G when floor prices exceed market prices, and carrying costs on Solar Renewable Energy Certificate inventory. As noted above, net gains or losses on the sale of Solar Renewable Energy Certificates also affect the total program costs.[31]

To date, although program costs have been incurred, the recovery of these costs has not yet been requested by the company.[32]

Carbon Abatement Program[33]

On December 16, 2008, the BPU adopted a Joint Position executed by PSE&G and BPU Staff which sets out a four-year pilot Carbon Abatement Program. The program has the following components (with associated program investment levels):

- Residential Home Energy Tune-Up Sub-Program ($26 million)
- Residential Programmable Thermostat Installation Sub-Program ($4 million)
- Small Business Direct Installation Sub-Program ($4 million)
- Large Business Best Practices and Technology Demonstration Sub-Program (1 million)
- Hospital Efficiency: Retrofit Sub-Program and New Construction Sub-Program (11 million)

According to the Joint Position, “PSE&G is entitled to recovery of all reasonable and prudent Program costs” and interest costs on net over and under recoveries at commercial paper or bank credit line rates. However, the company does not seek to recover lost revenues associated with these activities.

This program along with others is recovered through the Regional Greenhouse Gas Initiative (RGGI) Charge.[34, 35]

In October 2009, the company reported incurring both program investment and administrative costs.[36]

Energy Efficiency Economic Stimulus Program[37]

New Jersey Governor Jon Corzine announced a plan in October 2008 intended to support employment and economic activity in the short term and to enhance the state’s business climate and economic

[31] Responses to Discovery, OC-48 and OC-991.

[32] Decision and Order Approving Settlement in Docket No. EO07040278 dated April 16, 2008 provided in Response to Discovery, OC-48 (Attachment A4: p. 15) and review of current PSE&G tariffs posted on the company website.

[33] Decision and Order Approving Joint Position in Docket No. EO08060426 dated December 16, 2008 provided in Response to Discovery, OC-48 (Attachment A5) unless otherwise noted.

[34] Review of current PSE&G tariffs posted on the company website.

[35] New Jersey Governor Christie announced on 5/26/11 that New Jersey will leave the RGGI program by the end of this year.

[36] Response to Discovery, OC-991.

[37] Decision and Order Approving Stipulation in Docket No. EO09010056 dated July 16, 2009 provided in Response to Discovery, OC-48 (Attachment A7).

prospects in the long term. Part of this plan involved the investment of $500 million in energy efficiency programs by the state's electric and gas utilities. Shortly after this plan was announced, a New Jersey Energy Master Plan was released, which set a goal of reducing energy consumption by 20 percent by 2020. This goal was linked to the previously released energy efficiency initiative.

In response, PSE&G proposed eight energy efficiency sub-programs with a total investment of approximately $190 million over an eighteen-month period. The sub-programs included the following (budgets included in parentheses):

- Residential Whole House Efficiency Sub-Program ($10 million)
- Residential Multi-Family Housing Sub-Program ($19 million)
- Small Business Direct Installation Sub-Program ($20 million)
- Municipal/Local/State Government Direct Install Sub-Program ($25 million)
- Hospital Efficiency Sub-Program ($68 million)
- Data Center Efficiency Sub-Program ($10 million)
- Building Commissioning/O&M Sub-Program ($2 million)
- Technology Demonstration Sub-Program ($12 million)

The remaining $24 million of the total $190 million was expected to be spent on administration, sales, training, evaluation, and information technology costs. Costs of the various sub-programs included, but were not limited to, costs associated with energy audits, customer incentives to pursue energy efficiency upgrades, and zero percent financing.

The BPU ultimately approved a Stipulation entered into by the company, Staff, Rate Counsel and others on July 16, 2009. This stipulation permitted the recovery of costs associated with this program on a net revenue requirements basis through two new components of the RGGI charge – one for electric and one for gas. Revenue requirements of the program were to include both a return on and a return of investment as measured by the approved cost of capital in the most recent gas base rate case and a five-year amortization of the regulatory asset. Monthly interest on over- and under-recoveries were to be based on short-term interest rates (from pp. 8-9 of the Order). According to the January 2009 petition filed by the company, operation and maintenance expenses were to include allocated labor and associated overheads, program management, sales and marketing, program evaluation, training, and other staffing costs.[38]

The only costs incurred by the company in October 2009 consisted of program investment costs and certain administrative costs.[39]

[38] Response to Discovery, OC-48 Supplemental.
[39] Response to Discovery, OC-991.

Solar Generation Investment (Solar 4 All) Program[40]

In August 2009, the BPU approved a stipulation entered into by PSE&G and various parties which involved a significant investment by the company in solar generation. According to the stipulation, PSE&G will invest $514.6 million in an 80 MW utility-owned solar generation program that is divided into two primary segments – Centralized Solar and Neighborhood Solar. The Centralized Solar segment will include investments in solar systems installed on PSE&G-owned sites (25 MW), those installed on third party sites (10 MW), and those installed in "urban enterprise zones" (5 MW). The Neighborhood Solar segment (40 MW) will be comprised of small distributed solar systems on approximately 200,000 utility and street light poles within the utility's service territory.

Cost recovery will be accomplished through a new solar generation investment component of the RGGI charge and based on net revenue requirements of the program using the following formula (from pp. 4-6 of the Order):

(Net Investment x Pre-Tax Cost of Capital)
Plus: Amortization and/or Depreciation
Plus: Operation and Maintenance Costs
Minus: Revenues from Solar Output
Minus: Investment Tax Credit Amortization with Tax Gross Ups
Plus: Tax Associated from Investment Tax Credit Basis Reduction

Cost of capital will be 11.3092% on a pre-tax basis (most recently-approved gas base rate case return). Book and tax depreciation lives will range from 5 to 20 years depending on the asset class. O&M expense is expected to include labor and other costs necessary to manage the physical assets, administrative costs, rental costs, insurance expense, and the cost of removal. The company will also be able to recover interest costs on net over- or under-recoveries based on short-term interest rates.

According to the company, costs in October 2009 were limited to pole top capital costs and administrative costs of the various segments of the program.[41]

Demand Response Programs

In order to decrease total annual electricity consumption and electricity peak load in New Jersey and jump-start the demand response market in the state, the BPU accepted an interim plan on December 10, 2008 that was developed by the Demand Response Working Group in late 2007. The plan called for providing a premium payment to curtailment service providers who registered new or incremental capacity in the PJM Interruptible Load for Reliability program beginning on June 1, 2009.

[40] Order Approving Stipulation in Docket No. EO09020125 dated August 3, 2009 provided in Response to Discovery, OC-48 (Attachment A8).
[41] Response to Discovery, OC-991.

Both the premium payments and incremental administrative costs were to be recovered as a separate component of the RGGI Charge. Carrying charges on under- or over-recovered balances based on short-term interest rates were also permitted. Prudently incurred and reasonable administrative costs were capped at 15 percent of PSE&G's share of the state-wide program.[42]

Subsequent to the approval of this program, the BPU approved a second demand response program on July 31, 2009 that arose from a settlement between PSE&G, the New Jersey Attorney General's Office, and the Public Advocate of New Jersey, Division of Rate Counsel. This program consisted of two sub-programs – a Residential Central Air Conditioner Cycling Sub-Program and a Small Commercial Customer AC Cycling Sub-Program. Total investment for both sub-programs over a five-year period was expected to be $65 million, and targeted demand reduction was 150 MW. Three other sub-programs proposed by PSE&G during the same time frame were tabled until further review could be conducted.

Both of the approved sub-programs involve PSE&G providing cash incentives to customers who agree to install equipment that permits the company to control customer usage during times of peak load. The costs to be recovered under the program will follow a revenue requirements methodology as follows (from pp. 10-11 of the July 31, 2009 Order):

> (Net Investment x Cost of Capital)
> Plus: Amortization or Depreciation
> Minus: Demand Response Revenues
> Plus: Customer Incentives
> Plus: Administrative Costs

"Net investment" represents the program investment less accumulated depreciation or amortization. Cost of capital is equal to 11.3092%, the most recently approved base-rate-case, pre-tax return. The depreciation life of program investments is estimated to be ten years while capitalized software to manage the program will be amortized over five years. Administrative costs will consist of incremental labor and other related on-going costs to run the program.[43]

In 2009, the costs incurred for these programs consisted of outside contractors, marketing and promotions, administration, and other.[44]

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[42] Order in Docket No. EO08050326 dated December 10, 2008 and Order of Amendment in Docket No. EO08050326 dated April 27, 2009 (the latter provided in Response to Discovery, OC-48: Attachment A6).

[43] Order Adopting Settlement in Docket No. EO08080544 dated July 31, 2009 provided in Response to Discovery, OC-48 (Attachment A9).

[44] Response to Discovery, OC-991.

Capital Adjustment Charge[45]

In response to both an Economic Stimulus Plan and New Jersey Energy Master Plan issued in October 2008, PSE&G proposed a series of projects for inclusion in a Capital Infrastructure Investment Program that would be recovered through a new Capital Adjustment Charge. These projects were characterized as incremental in nature and thus would create jobs in support of the Governor's Economic Stimulus Plan. PSE&G and other interested parties ultimately filed a proposed stipulation on the matter which the BPU approved on April 28, 2009.

As stipulated, the scope of the program involved 38 qualifying projects and totaling $694 million. Cost recovery through the Capital Adjustment Charge was proposed to be approved by the BPU on an interim basis and subject to refund. As part of the stipulation, it was agreed that a prudency review would be conducted in the company's next base rate case which was to be filed between April 3, 2009 and April 1, 2011.

Using a revenue requirements methodology, both a return on and a return of investment through depreciation was proposed. Depreciation rates and methodologies were based on those most recently approved in PSE&G electric and gas base rate cases. Cost of capital was based on the company's most recent gas base rate case of 11.3092% (pre-tax). The initial Capital Adjustment Charge was based on projections subject to annual adjustments. Interest on monthly over- and under-recoveries was based on short-term interest rates (from pp. 4-5 of the Order). The February 4, 2009 supplemental filing concerning this program defines operations and maintenance costs as "only the initial training and non-productive time of new hires related to the Program."[46]

In October 2009, PSE&G disclosed that it had incurred the following types of costs: labor, fringes, direct material, traffic control, outside services construction, paving contractors, permits, equipment rental, assessments, and various surcharges.[47]

Non-Rate Related Revenues

According to the company, PSE&G gains and revenues <u>not</u> derived from utility rates since 2003 were largely comprised of the following:[48]

- Sunburst Solutions utility billing services – These services were offered to small companies up until 2007 when the organization ceased doing business. For rate case purposes, the revenues and costs were included as operating income.

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[45] Decision and Order Approving Stipulation in Docket No. EO09010049 dated April 28, 2009 provided in Response to Discovery, OC-48 (Attachment A10).
[46] Response to Discovery, OC-48 Supplemental.
[47] Response to Discovery, OC-991.
[48] Responses to Discovery, OC-896 and OC-78. In response to our request for gains and revenues recorded by PSE&G since its last rate case other than those derived from utility rates, the company responded with a listing of ". . . amounts recorded in other income and revenue accounts since 2003."

- Fiber optics income and expenses – In the 2003 rate case, both income and expense were included as a contribution to operating income. Since 2007, they have been recorded as other operating revenues. According to the company, the change in treatment was the result of a review accounts in preparation for future rate filings and in order to comport with the BPU's prior rate order in 2003.[49]

- Equity in earnings of subsidiary companies – This income is not included in the determination of base rates since the investment in subsidiaries is not included in rate base.

- Realized gains (and losses) on the Rabbi Trust – Rabbi Trusts are grantor trusts in which assets have been set aside to fund supplemental retirement and deferred compensation of certain executives. Similar to the equity in earnings of subsidiary companies, the income effect of these trusts has been excluded from the determination of base rates because the investment has been excluded from rate base.

- Transition Funding Service fees included in the Securitization Transition Charges (STC) clause.

- Tax gross-ups on contributions in aid of construction (CIAC) – Customers making contributions make the company whole for the tax timing difference created by the contribution. Property is added to rate base at zero cost.

- Offset to amortization of Repair Allowance & Restructuring – The BPU 2003 rate order provided mortgage-like recovery of disallowed tax deductions associated with a repair allowance over a ten-year period with a full return. For BPU purposes, PSE&G records amortization expense equal to the return component with the offsetting amount to Other Income.

- Gains (and losses) on sales of property – In setting base rates, a five-year average of gains and losses on the disposition of property is calculated with 50 percent of the resulting net gain on electric and gas distribution property shared with customers.

The annual amounts recorded for each of these items is summarized in the following table:

[49] E-mail correspondence dated February 7, 2011.

Table 11-8 – Non-Rate Related Revenues and Income

Non-Rate Related Revenues and Income Amounts in 000's							
Description	Acct No.	2004	2005	2006	2007	2008	2009
Sunburst Solutions Revenues	415	$353	$339	$220	$48	$ --	$ --
Sunburst Solutions Costs	416	(244)	(204)	(130)	(111)	--	--
Fiber optics income (primarily)	417	7,536	7,915	7,188	--	--	--
Fiber optics expenses (primarily)	417.1	(476)	(703)	(211)	--	--	--
Equity earnings of subsidiaries	418.1	240	(16)	670	1,023	578	(708)
Realized gains on Rabbi Trust	421	966	108	--	756	658	109
Transition Funding Service fee	421	125	125	250	250	250	250
Tax gross-ups on CIAC	421	--	607	8,691	1,527	3,947	3,147
Repair Allowance & Restructuring	421	9,024	8,320	7,566	6,763	5,909	4,999
Other	418 & 421	(31)	(256)	(15)	(16)	(25)	(9)
Gain on disposition of property	421.1	(531)	2,423	3,093	2,914	890	2,110
Loss on disposition of property	421.2	--	--	(13)	--	--	--
Total		16,962	18,658	27,309	13,154	12,207	9,898

Sources: Responses to Discovery, OC-896 and OC-897.

FERC Acct Number Descriptions:
- Acct No. 415 – Revenues from Merchandising, Jobbing and Contract Work
- Acct No. 416 – Costs and Exp. Of Merchandising, Job. & Contract Work
- Acct No. 417 – Revenues from Nonutility Operations
- Acct No. 417.1 – Expenses of Nonutility Operations
- Acct No. 418 – Nonoperating Rental Income
- Acct No. 418.1 – Equity in Earnings of Subsidiary Companies
- Acct No. 421 – Miscellaneous Nonoperating Income
- Acct No. 421.1 – Gain on Disposition of Property
- Acct No. 421.2 – Loss on Disposition of Property

In recent years, the most significant non-rate related revenues and income are the tax gross-ups on CIAC, the Repair Allowance & Restructuring, and gains on disposition of property. With respect to the latter, the gains and losses recognized by the company have resulted from dispositions of electric distribution, electric transmission, and gas distribution assets. The amounts associated with each type of property broken out by land, structures, and other are summarized in the following table:

Table 11-9 – Gains (Losses) on Disposition of Property

Gains (Losses) on Disposition of Property Amounts in 000's						
Description	2004	2005	2006	2007	2008	2009
Electric Distribution:						
Land	$26	$22	$573	$ --	$504	$ --
Structures	11	5	(5)	--	--	--
Sub-Total	37	27	568	--	504	--
Electric Transmission:						
Land	802	2,396	60	2,731	156	2,110
Structures	--	--	--	--	--	--
Sub-Total	802	2,396	60	2,731	156	2,110
Gas Distribution:						
Land	--	--	2,456	183	230	--
Structures	--	--	(8)	--	--	--
Sub-Total	--	--	2,448	183	230	--
Other Common Assets	--	--	4	--	--	--
Other (A)	(1,370)	--	--	--	--	--
TOTAL	(531)	2,423	3,080	2,914	890	2,110
Account 421.1	$(531)	$2,423	$3,093	2,914	890	2,110
Account 421.2	--	--	(13)	--	--	--
TOTAL	(531)	2,423	3,080	2,914	890	2,110

Source: Response to Discovery, OC-897.

(A) Consists of a reclassification of a loss on sale of the Front St property (manufactured gas plant) to NJ Investment Account totaling $3,785,619 and 50 percent of the gain on the sale of the Port Reading property totaling $2,414,901.

Additional details of all dispositions of property resulting in a recorded gain or loss are provided in Attachment 11-1.

When asked to provide "authoritative guidance" or the "basis" for the company's policy on sharing these gains and income with ratepayers, PSE&G gave no formal response.[50] However, in informal discussions with a company representative, we were told that although sharing had not been explicitly adopted in a prior rate proceeding, the BPU had implicitly adopted such a sharing methodology in the 2002 electric rate case (Docket No. ER02050303) and in the 2005 gas rate case (Docket No. GR05100845).[51]

[50] Responses to Discovery, OC-78 and OC-896.
[51] E-mail correspondence dated January 28, 2011.

In 2009, PSE&G petitioned the BPU to increase both its electric and gas base rates. In filed testimony, the company proposed sharing one-half of the gain on sales of property, net of income tax, with ratepayers. To avoid distortions caused by abnormally high or low gains in any given year, the company proposed using a five-year average.[52]

The request for a rate increase was ultimately resolved in 2010 when the BPU approved a stipulation of settlement between PSE&G and various parties, including the Staff. The key provisions of the stipulation are silent on the matter of the sharing of gains on property sales and other items previously described.[53]

[52] Response to Discovery, OC-135, p. 1862 of 1915 (Supplemental Testimony of Mark G. Kahrer, Vice President-Finance in Docket No. GR09050422).

[53] Response to Discovery, OC-1054 (Decision and Order Approving Stipulation and Adopting Initial Decision for Electric Division dated June 7, 2010 in Docket No. GR09050422 and Decision and Order Adopting Initial Decision with Modification for Gas Division dated July 9, 2010 in Docket No. GR09050422).

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RESPONSE TO OVERLAND CONSULTING
REQUEST: OC-897
PAGE 1 OF 4
MANAGEMENT & AFFILIATE AUDIT 2009

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

PROPERTY SALES

QUESTION:
Please update the information requested in OC-49 through the end of 2009.

ANSWER:
The attached spreadsheet has been updated to include property sales through 2009. In addition the FERC accounts charged with the gain or loss is noted and the annual amounts are reconciled to the FERC Form 1 and the BPU Annual Report.

		Date of Closing	Location of Property	FERC Accts	Description of Property	Book Cost	Proceeds	Sale expenses	Accumulated Depreciation	Gain /(Loss)	Gain & Loss Account Used	FERC Form 1 /BPU Total	FERC Form1 Page No.
2003- Sales													
Electric Distribution													
	Land:	Oct-03	Robbinsville Substation	121	Sale of 0.502 acres of land	$ 4,429	37,882	2,045		31,408			
		Nov-03	Preakness Substation	121	Sale of 1.594 acres of land	$ 14,106	119,606	6,573		98,927			
		Dec-03	Sip Ave Substation	121	Sale of 0.27 acres of land	$ 36,610	92,143	5,131		50,402			
		Dec-03	Atlantic Ave Substation	121	Sale of 0.49 acres of land	$ 26,764	41,000	2,214		12,022			
		Dec-03	Delanco Substation	121	Sale of 0.858 acres of land	$ 5,402	16,500	891		10,207			
		Dec-03	Groveville Substation	121	Sale of 0.517 acres of land	$ 2,989	53,000	2,862		47,149			
		Dec-03	Mulberry St Garage	101	Sale of 0.157 acres and easement of 0.08 acres	$ 21,321	444,161	-		422,840			
		Dec-03	Miller St Substation	121	Sale of 0.26 acres of land	$ 35,600	385,000	21,628		327,772			
	Structures:	Oct-03	Robbinsville Substation	121	Sidecurbs & Structures	$ 293	2,618	141	(187.16)	2,370			
		Nov-03	Preakness Substation	121	Sidecurbs & Structures	$ 50,214	100,394	5,518	(54,633.54)	99,296			
		Dec-03	Sip Ave Substation	121	Sidecurbs & Structures	$ 103,027	202,857	11,295	(22,427.65)	110,963			
			Sub-total- Gain-Electric Distribution			$ 300,755	$ 1,495,161	$ 58,298	$ (77,248)	**$ 1,213,357**	**421.1**		
	Land:	Dec-03	Federal Sq. Substation	121	Sale of 1.27 acres of land	$ 198,661	205,408	22,033		(15,286)			
			Sub-total- Loss-Electric Distribution							**$ (15,286)**	**421.2**		
			2003 Total - Electric Distribution							**$ 1,198,070**			
Electric Transmission													
	Land:	Jan-03	Right of Way-Sewaren-Brunswick & others	101	Easement of 21,572 linear feet of land	$ 21,877	6,000,000			5,978,123			
		Jan-03	Delaware River Bulkhead line	121	Sale of 52.181 acres and easement of 1.15 acres of land	$ 364,824	1,850,000			1,485,176			
		Apr-03	Right of Way- Hudson Bergen	101	Sale of 2.21acres of land	$ 20,385	595,000			574,615			
		Oct-09	Right of Way-Branchburg -Suffern	101	Sale of 3.848 acres of land	$ 7,730	11,000	44		3,226			
		Oct-03	Right of Way-Roseland-Lambertville	101	Sale of 0.17acres of land	$ 335	30,000	120		29,545			
		Dec-09	Fed Sq Substation	121	Sale of 1.27acres of land	$ 180,464	186,592			6,129			
		Dec-09	Right of Way- Athenia-Roseland	101	Easement of 150 sq feet of land	$ 133	5,000			4,867			
		Dec-09	Right of Way-Deans-Branchburg	101	Sale of land 0.41 acres of land	$ 3,368	47,300			43,932			
		Dec-03	Right of Way-Roseland-Lambertville	101	Consent of 8213 sq feet of land	$ -	697,000			697,000			
			2003 Total - Electric Transmission			**$ 599,114**	**$ 9,421,892**	**$ 164**	**$ -**	**$ 8,822,614**	**421.1**		
Other Common Assets													
		May-03	Gain on disposition of other assets							$ 430,384	**421.1**		
Not included in the scope of the Management Audit													
		Dec-03	Newak Front Street Property (MGP)							1,585,937			
		2003	**Total Net Gain on Disposition of Property**							**$ 12,037,006**	**421.1**	**12,037,006**	**Pg 117 line 40 C**
2004 - Sales													
Electric Distribution													
	Land:	Jan-04	Hoover Ave Substation	121	Sale of 0.22 acres of land	$ 1,575	36,786	189		35,022			
		Jan-04	Rosedale Substation	121	Sale of 1.831 acres of land	$ 4,505	65,000	260		60,235			
		Mar-04	Ceder Lane Substation	121	Sale of 1.06 acres of land	$ 5,494	90,000	575		83,931			
		Apr-04	Trenton -Woodbury Loop	101	Easement of 2.602 acres of land	$ 37,784	125,394	-		87,610			
		Dec-04	New Market Substation	121	Sale of 0.58 acres of land	$ 3,308	110,000	813		105,879			
		Dec-04	Burlington ROW	101	Easement of 0.57 acres of land	$ -	1,500	-		1,500			
		Dec-04	Little Falls Substation	121	Sale of 0.17 acres of land	$ 4,248	48,000	189		43,562			
		Dec-04	Ingleside Substation	121	Sale of 1.770 acres of land	$ 10,852	66,500	277		55,372			
		Nov-04	New Brunswick & Coal Street		Adjust. to 2001(New Brunswick) & 2002 (Coal St) Gain					(457,530)			
		Apr-04	ADJ-Fed Sq Substation Sale in 2003		Adjustment to 2003 Gain on sale			(10,488)		10,488			
	Structures:	Jan-04	Hoover Ave Substation	121	Structures	$ 464	11,614	3	(104)	11,250			
			2004 Total - Electric Distribution			**$ 68,230**	**$ 554,794**	**$ (8,182)**	**$ (104)**	**$ 37,320**	**421.1**		
Electric Transmission													
	Land:	Jan-04	Center Line in Branchburg	101	Easement of 0.032 acres of land	$ 45	100,000			99,955			
		Jan-04	Center Line in Branchburg	121	Sale of 0.10 acres of land	$ 267	113,000			112,733			
		Jan-04	Right of Way-Brunswick-Branchburg	101	Sale of 0.04 acres and easement of 0.11acres of land	$ 636	24,000			23,364			
		Mar-09	Right of Way-Metuchen-Trenton ROW	101	Easement of 8,780 sq feet of land	$ -	12,000			12,000			
		Mar-09	Right of Way - Roseland Metuchen	101	Sale of 0.30 acres of land	$ -	78,000	312		77,688			
		Apr-04	ADJ-Fed Sq Substation Sale in 2003		Adjustment			10,488		(10,488)			
		Jun-04	Right of Way-Sewaren-Metuchen	101	Sale of 0.26 acres of land	$ 500	101,500	384		100,616			
		Sep-04	Smerville Substation	101	Easement of 0.38 acres of land	$ 1,271	51,000			49,729			
		Oct-03	ADJ-Right of Way-Roseland-Lambertville(2003)		Adjustment			2,500		(2,500)			

		Date of Closing	Location of Property	FERC Accts	Description of Property	Book Cost	Proceeds	Sale expenses	Accumulated Depreciation	Gain /(Loss)	Gain & Loss Account Used	FERC Form 1 /BPU Total	FERC Form1 Page No.
		Apr-04	Trenton -Woobury Loop	101	Easement of 0.062 acres of land	$ 35,510	374,606			339,096			
			2004 Total - Electric Transmission			**$ 38,229**	**$ 854,106**	**$ 13,684**	**$ -**	**$ 802,192**	**421.1**		
Not included in the scope of the Management Audit													
		Feb-04	Reclass of Gain on Sale of Front St Property (MGP) to NJ Investment Account							$ (3,785,619)			
		Oct-04	50% Gain on Sale of Port Reading Property							$ 2,414,901			
		2004	**Total Net Loss on Disposition of Property**							**$ (531,205)**	**421.1**	**(531,205)**	**Pg 116 line 40 C**
2005- Sales													
Electric Distribution													
	Land:	Sep-05	US Route 30 Right of Way	101	Easement of 0.008 acres of land	$ 13	500			487			
		Sep-05	State St Substation	101	Sale of 0.043 acres of land	$ 1,507	3,100			1,593			
		Sep-05	Washington Ave R/W	101	Sale of 0.160acres of land	$ -	4,800			4,800			
		Oct-05	York Road Substation	121	Sale of 0.350acres of land	$ 819	10,093			9,274			
		Oct-05	Quaker Farm House-Merrill Creek	121	Sale of 0.86 acres of land	$ 6,406	30,001			23,595			
	Structure:	Oct-05	Quaker Farm House-Merrill Creek	121	Structure	$ 1,460	6,835			5,376			
			Sub-total- Gain-Electric Distribution			**$ 10,206**	**$ 55,330**	**$ -**	**$ -**	**$ 45,124**	**421.1**		
	Land:	Jan-05	Raritan canal	101	Sale of 0.149 acres and easement of 0.058acres	$ 83,117	77,600			(5,517)			
		Nov-05	Wall Street Substation	121	Sale of 28,128 sq ft of land	$ 12,727	-			(12,727)			
			Sub-total- Loss-Electric Distribution							**$ (18,245)**	**421.2**		
			2005 Total - Electric Distribution							**$ 26,879**			
Electric Transmission													
	Land:	Mar-05	Trenton Woobury Loop		Adjustment for Selling Expense			10,000		(10,000)			
		Oct-05	Right of Way-Athenia-Roseland	101	Sale of 0.05 acres and easement of 0.011 acres of land	$ 914	7,460			6,546			
		Dec-05	Right of Way - Route 1 (Woodbridge Center dri	101	Sale of 5.568 acres and easement of 2.462 acres of land	$ 320	2,400,000			2,399,680			
			2005 Total - Electric Transmission			**$ 1,234**	**$ 2,407,460**	**$ 10,000**	**$ -**	**$ 2,396,226**	**421.1**		
		2005	**Total Gain on Disposition of Property**							**2,423,105**	**421.1**	**2,423,105**	**Pg 116 line 40 C**
2006- Sales													
Electric Distribution													
	Land:	Feb-06	Tonnelle Avenue Substation	101	Sale of 174.24 sq ft of land	$ 115	3,243			3,128			
		Aug-06	Lake Nelson Substation	101	Sale of 0.608 acres and Easement of 0.046acres	$ 2,087	32,000			29,913			
		Nov-06	North Arlington Substation	121	Sale of 1.43acres of land	$ 16,989	586,546	29,500		540,057			
			Sub-total- Gain-Electric Distribution							**$ 573,098**	**421.1**		
	Structure:	May-06	Erlton Substation	121	Curbs & Structures	$ 7,376	-		(2,251)	(5,125)			
			Sub-total- Loss-Electric Distribution							**$ (5,125)**	**421.2**		
			2006 Total - Electric Distribution							**$ 567,973**			
Other Common Assets													
		Feb-06	Gain on disposition of other assets							3,500.00	**421.1**		
Electric Transmission													
	Land:	Jan-06	Right of Way - Sewaran -Metuchen	101	Sale of 0.74acres and 0.161acres of easement	$ -	60,000			60,000	**421.1**		
Gas Distribution													
	Land:	Jan-06	Tonnelle Avenue Substation	101	Sale of 3125 square feet of land	$ 1,248	35,157			33,909			
		Nov-06	Port Reading -Woodbridge City Gate Station (M	121	Sale of 228.69 acres of land	$ 7,012,862	12,000,000			2,422,187			
			Sub-total- Gain -Gas Distribution							**$ 2,456,096**	**421.1**		
		Apr-06	Non Utility Property	121	Curbs & Structures	$ 12,806			(4,479)	(8,327)			
			Sub-total- Loss-Gas Distribution							**$ (8,327)**	**421.2**		
			2006 Total - Gas Distribution							**$ 2,447,769**			
		2006								3,092,694	**421.1**	3,092,694	**Pg 116 line 40 C**

	Date of Closing	Location of Property	FERC Accts	Description of Property	Book Cost	Proceeds	Sale expenses	Accumulated Depreciation	Gain /(Loss)	Gain & Loss Account Used	FERC Form 1 /BPU Total	FERC Form1 Page No.
	2006				NO LAND SALES FOR DELIVERY COMPANY				(13,452)	**421.2**	(13,452)	**Pg 116 line 43 C**
2007- Sales												
Electric Transmission												
Land:	Jan-07	Right of Way- Newbold-New Freedom	121	Sale of 0.03 acres of land	$ 238	1,000			762			
	Jan-07	Right of Way-New Freedom Deans	101	Sale of 0.620 acres of land	$ 4,423	33,107			28,684			
	Aug-07	Right of Way-New Freedom Deans	101	Easement of 0.210 acres of land	$ 1,968	5,775			3,807			
	Aug-07	Right of Way-New Freedom Deans	101	Sale of 0.861 acres of land	$ 11,735	26,000	146		14,119			
	Aug-07	Right of Way - Sewaran -Metuchen	101	Sale of 16.0149 acres of land	$ 16,271	2,700,000			2,683,729			
		2007 Total - Electric Transmission			**$ 29,974**	**$ 2,731,775**	**$ 146**	**$ -**	**$ 2,731,101**	**421.1**		
Gas Distribution												
Land:	Apr-05	Paterson Gas Plant (MGP)	121	Sale of 2.06 acres of land	$ 104,594	288,400	1,218		182,588	**421.1**		
	2007								**2,913,689**	**421.1**	**2,913,689**	**Pg 116 line 40 C**
2008- Sales												
Electric Distribution												
Land:	Jan-08	Bergen Switching Station	101	Easement of 0.005 acres of land	$ 105	360			255			
	Jan-08	Right of Way - Harrison Avenue	101	Sale of 0.04 acres of land	$ 0	3,150			3,150			
	Mar-08	Right of Way - Broadway	101	Easement of 0.122 acres of land	$ 33	6,700			6,667			
	Jul-08	Right of Way - Harrison Avenue-(Meadows)	101	Sale of 1.512 acres of land	$ 6,893	220,333			213,440			
	Jul-08	Right of Way - Westville	101	Sale of 4.79 acres of land	$ 591	95,000			94,409			
	Dec-08	Easement of 80"Right of Way	101	Easement of 0.555 acres of land	$ 10	186,000			185,990			
		2008 Total - Electric Distribution			**$ 7,632**	**$ 511,543**	**$ -**	**$ -**	**$ 503,911**	**421.1**		
Electric Transmission												
Land:	Jan-08	Bergen Switching Station	101	Easement of 0.005 acres of land	$ 220	755			536			
	May-08	Right of Way - Roseland Metuchen	101	Easement of 0.181 acres of land	$ 0	14,500			14,500			
	Jul-08	Right of Way - Hillcrest Road	101	Sale of 9.54 acres of land	$ 14,429	136,790			122,361			
	Jul-08	Right of Way - Harrison Avenue-(Kearny)	101	Sale of 0.125 acres of land	$ -	18,315			18,315			
	Jul-08	Right of Way - Sewaran -Metuchen	101	Easement of 0.036 acres of land	$ 14	1,000			986			
		2008 Total - Electric Transmission			**$ 14,663**	**$ 171,360**	**$ -**	**$ -**	**$ 156,697**	**421.1**		
Gas Distribution												
Land:	Jan-08	Right of Way - Town of Kearny	101	Sale of 0.651 acres of land	$ -	40,600			40,600			
	Jan-08	Right of Way - Harrison Avenue	101	Sale of 0.04 acres of land	$ 1	3,150			3,150			
	Dec-08	Kearny 80" Right of Way	101	Easement of 0.555 acres of Land	$ 10	186,000			185,990			
		2008 Total - Gas Distribution			**$ 11**	**$ 229,750**	**$ -**	**$ -**	**$ 229,740**	**421.1**		
	2008								**890,348**	**421.1**	**890,348**	**Pg 116 line 40 C**
2009- Sales												
Electric Transmission												
Land:	Mar-09	Roseland -West Orange ROW	101	Easement of 0.460 acres of land	$ 1,283	$ 93,000			91,717			
	Jun-09	Athenia - Roseland Transmission Line	101	Easement of 10.905 acres of land	$ 37,964	$ 1,900,000			1,862,036			
	Jun-09	Bordentwn &Mansfield Twp	101	Easement of 6.756 acres of land	$ 40,808	$ 197,270			156,462			
		2009 Total - Electric Transmission			**$ 80,055**	**$ 2,190,270**	**$ -**	**$ -**	**$ 2,110,215**	**421.1**		
	2009								**2,110,215**	**421.1**	**2,110,215**	**Pg 116 line 40 C**

12. ACCOUNTING AND PROPERTY RECORDS

As with many other administrative functions, PSE&G's accounting is largely handled in a centralized manner by PSEG Services Corporation. Most accounting-related departments currently report to Caroline Dorsa, Executive Vice President and Chief Financial Officer.

PSEG's and its subsidiaries' accounting is predominately performed on a third-party software platform designed by SAP. PSEG's reliance on SAP was recently strengthened when the company converted its legacy customer information system to SAP in April, 2009.

Internal controls employed by the company play a critical role in providing reasonable assurance that financial reporting is reliable. In addition, internal controls are designed, among other things, to optimize operational efficiency and to encourage compliance with internal policies and procedures and external rules and regulations. The objective of our review of controls over accounting and property records was to identify areas for improvement or refinement of processes. With that in mind, we did not independently sample test for compliance with internal control procedures or otherwise duplicate work already performed by PSEG's external and internal auditors.

Findings

1. A number of shared accounting and finance-related departments have been consolidated into the CFO organization in recent years. From an administrative standpoint, this includes the Internal Audit group which previously had reported to the General Counsel.
2. Departmental performance is measured through the use of balanced scorecards, the targets of which are based on either benchmarking or continuous improvement according to the company. For the accounting-related departments we reviewed, performance generally exceeded management expectations.
3. While not a significant cost component, 2008 benchmarking results indicated that PSEG payroll processing costs were much higher than best performers. PSEG has taken steps to close this gap including the use of electronic pay advices, electronic tax filings, and relocation expense automation; but the adoption of other best practices is not allowed according to the company.
4. **[Begin Confidential]**

   [End Confidential]
5. Internal controls over financial reporting are reviewed extensively by three different groups – the Internal Audit Department, the Internal Controls group, and the external auditors (Deloitte & Touche LLP).
6. Neither PSEG nor PSE&G discovered any significant deficiencies or material weaknesses with internal controls over financial reporting for any of the past three years (2007-2009).

Furthermore, Deloitte & Touche LLP opined that PSEG has maintained effective internal controls over financial reporting for this time period.

7. **[Begin Confidential]** **[End Confidential]** For those audits involving processes which impact PSE&G, all but one of the identified weaknesses had been remediated by mid-2010.

8. Sarbanes-Oxley Section 404 testing shows both a decrease in the number of total internal control failures and unremediated year-end failures from 2007 to 2009.

9. Management and the board of directors assess the retention of the external auditor, Deloitte & Touche LLP, on an annual basis. In recent years, they have concluded that the benefits of continuing their long-standing relationship with this firm outweigh the one-time costs and potential benefits they may achieve with a new firm.

10. PSE&G has not recorded any asset impairments since the beginning of 2007. The asset impairments recorded by PSE&G affiliates over the same time period have been relatively insignificant to PSEG's consolidated earnings.

Recommendations

1. To conform to industry guidance and practice and to promote the appearance of independence, the Internal Auditing Services group headed by its vice president, William Metzger, should report administratively to the PSEG CEO, Ralph Izzo, rather than to the CFO as is currently the case.

2. PSEG should implement employee payroll self-service data maintenance as a cost saving strategy.

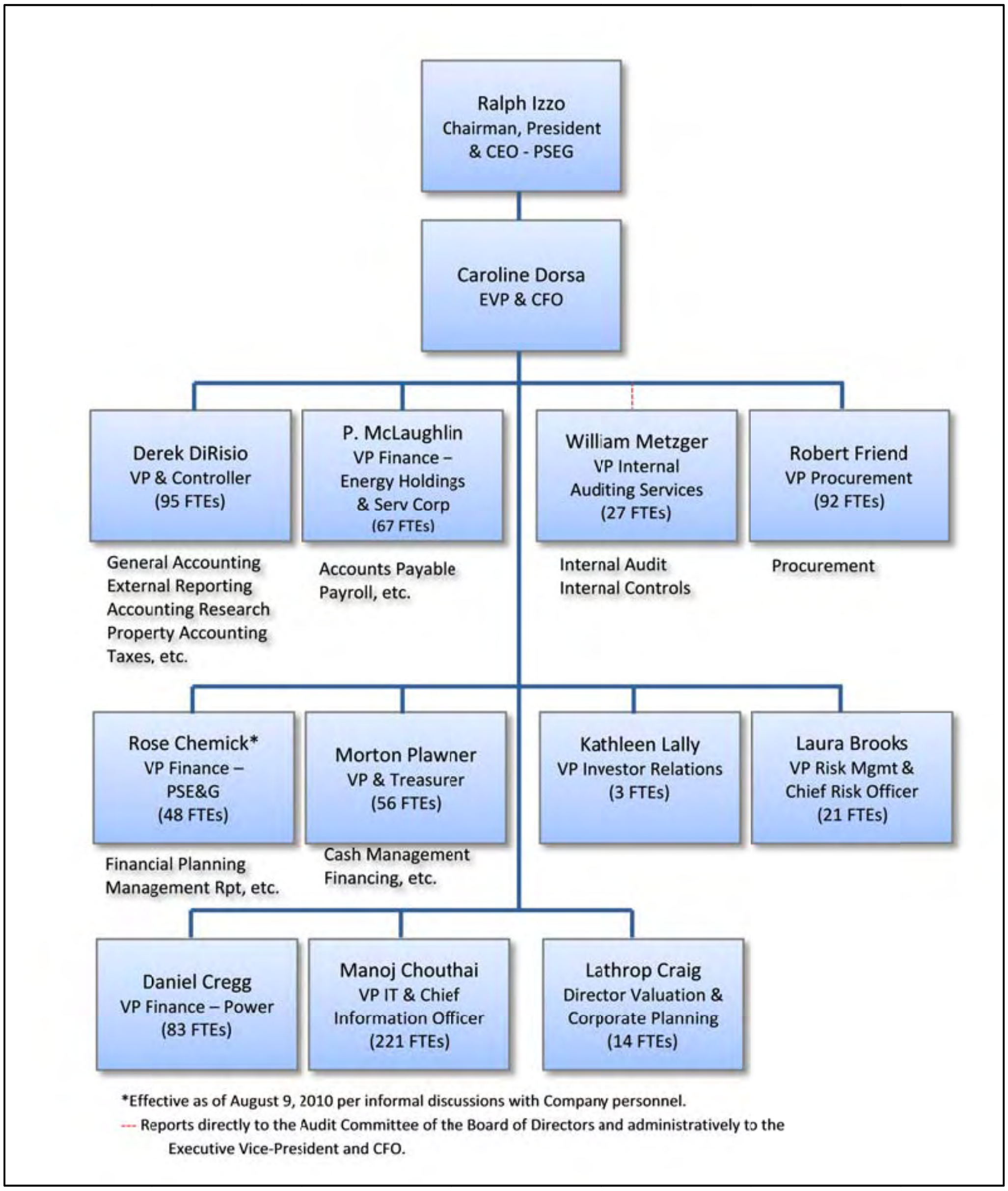
3. The PSEG Audit Committee Charter should be modified to explicitly state that the Audit Committee is responsible for reviewing and approving the internal audit plan for the upcoming year.

4. Since it has been outstanding for over three years, PSEG should provide the BPU 1) an estimate of the cost to remediate the significant control weakness associated with manual non-purchase order checks and 2) quarterly status reports on this outstanding audit finding until completely remediated and validated by Internal Audit.

Organization and Staffing

The primary accounting functions performed on behalf of PSE&G are carried out by employees of PSEG Services Corporation.[1] Most of these functions currently reside within a group headed by Caroline Dorsa, Executive Vice President and Chief Financial Officer as demonstrated in the following organization chart:[2]

Table 12-1 - PSEG Services Corporation Organization Chart



[1] Response to Discovery, OC-214.
[2] Response to Discovery, OC-1270 and interviews with Daniel Furlong, Assistant Controller – PSE&G on July 7, 2010 and Derek DiRisio, Vice President and Controller on July 8, 2010.

The one notable accounting function handled elsewhere in the PSEG organization is Accounts Receivable which is the responsibility of Joseph Forline, Vice President – Customer Operations. Mr. Forline reports directly to Ralph LaRossa, President and Chief Operating Officer of PSE&G. Mr. LaRossa, in turn, is a direct report of Mr. Izzo's.

The organization presented above is the result of a number of relatively recent changes. Some of the more significant changes include:

- Until August of 2010, the PSE&G Finance Department headed currently by Rose Chernick reported to Ralph LaRossa.[3]

- The Finance Department for PSEG Services Corporation headed by Patricia McLaughlin reported to Elbert Simpson, President and Chief Operating Officer of PSEG Services Corporation, until his retirement in early 2010. The Information Technology and Procurement Departments also reported to Mr. Simpson prior to his retirement.[4]

- The Internal Audit Group previously reported administratively to the Executive Vice President & General Counsel. When Ms. Dorsa replaced Thomas O'Flynn in 2009, an organizational realignment occurred, including the movement of Internal Audit to the recently hired CFO's organization.[5]

- The Internal Controls group which currently reports to William Metzger, Vice President – Internal Auditing Services, used to report to Laura Brooks, Vice President – Risk Management. This was done to take advantage of organizational synergies between Internal Audit and Internal Controls in managing Sarbanes-Oxley compliance.[6]

The recent consolidation of finance-related departments within the CFO organization generally makes good business sense. The communication of management expectations is more effective when coming from one executive rather than several. Common management increases the likelihood that departments with overlapping responsibilities will collaborate with each other. Redundancy in responsibilities and associated headcount should be easier to identify and eliminate.

However, in at least one instance, further reorganization is warranted. With respect to the Internal Audit Department and its head (generally referred to as the Chief Audit Executive or CAE), the Internal Audit Standards Board takes the following position:

[3] Derived from a review of responses to Discovery, OC-5 (Restricted) and OC-1270 and informal discussions with company personnel.

[4] Responses to Discovery, OC-5 (Restricted) and OC-1133 and interview with Patricia McLaughlin, Vice President – Finance of Energy Holdings and PSEG Services Corporation on August 2, 2010. Ms. McLaughlin also picked up the additional responsibility of heading the Energy Holdings' Finance Department during this same time period.

[5] Response to Discovery, OC-602 and interviews with members of the board of directors.

[6] Response to Discovery, OC-1050.

. . . The Institute [of Internal Auditors] believes strongly that to achieve necessary independence, the CAE should report functionally to the audit committee or its equivalent. For administrative purposes, in most circumstances, the CAE should report directly to the chief executive officer of the organization (Practice Advisory 1110-2). (Emphasis added)

In an August 24, 2010 benchmarking study produced by the Global Audit Information Network, 50 percent of Edison Electric Institute participants and 44 percent of gas and electric utility participants had their Chief Audit Executive report to the CEO, eclipsing the 38 percent and 38 percent, respectively, that report to the CFO.[7]

Even if just for appearances sake, it makes sense to have the Internal Audit Department and its head administratively report to someone besides the CFO. As demonstrated in the organization chart above, the CFO is responsible for many of the functions that Internal Audit specifically reviews (e.g., internal controls). From a perception standpoint, this is a conflict of interest that could easily be avoided with a simple reorganization.

For all of the preceding reasons, we recommend that the head of the Internal Audit Department report administratively to the Chief Executive Officer of PSEG.

Accounting Functions

The vast majority of personnel holding accounting-related positions are based in the 80 Park Plaza office building in Newark, New Jersey.[8] In most cases, the accounting-related groups within PSEG Services Corporation are not dedicated solely to PSE&G. The two exceptions to this are the a group of employees reporting to Daniel Furlong in the Controller's Department and the Finance Department headed by Rose Chernick.[9]

The following is our best assessment of the current accounting function organization based on the information we were provided:[10]

- Controller's Department – This department is responsible for the standards, policies, procedures and processes governing the use of the general ledger of the corporation and its subsidiaries. This department is also responsible for internal and external financial reporting, income tax planning and compliance, accounting research, and property accounting (95 full-time equivalents (FTEs)).

[7] Response to Discovery, OC-1014 Update (Global Audit Information Network August 24, 2010 Benchmarking Report), p. 66 of 173.
[8] Based on a review of responses to Discovery, OC-929 (Restricted) and OC-63.
[9] Interviews with Daniel Furlong, Assistant Controller – PSE&G on July 7, 2010 and Patricia McLaughlin, Vice President – Finance of Energy Holdings and PSEG Services Corporation on August 2, 2010.
[10] Derived from responses to Discovery, OC-73, OC-1270 and interviews with Derek DiRisio, Vice President and Controller on July 8, 2010; Patricia McLaughlin, Vice President – Finance of Energy Holdings and PSEG Services Corporation on August 2, 2010; and Daniel Furlong, Assistant Controller – PSE&G on July 7, 2010.

- Energy Holdings and PSEG Services Corporation Finance Department – In addition to the planning, analysis, forecasting, and management reporting performed for Energy Holdings (a PSE&G non-regulated affiliate), this department is responsible for the transaction center of the company which includes enterprise-wide payroll, payroll taxes, accounts payable, and business expense reimbursement. This group also oversees the cost allocation process and records management function of the enterprise (67 FTEs).

- Internal Auditing Services – This group oversees independent reviews and evaluations of the company's financial and operational controls, performs investigations on an as needed basis, and administers the company's compliance with Sarbanes-Oxley (27 FTEs).

- PSE&G Finance Department – This department is responsible for financial planning (long-term and short-term), financial analysis (actual-to-budget comparisons), business analysis, management reporting, and rates and revenue requirements for PSE&G (56 FTEs).

- Valuation and Corporate Planning Department – Among other things, this department assists senior management with the development, maintenance, and communication of the financial plan. It also develops cost of capital studies and valuation studies of businesses or assets (14 FTEs).

- Billing and Revenue Operations – Unlike the previous departments, as previously mentioned, this group reports to the Joseph Forline, Vice President - Customer Operations. This department is responsible for leading the revenue cycle process which includes billing, credit and collection, revenue integrity, payment assistance outreach, bad debt management, and payment processing (180 FTEs).

Accounting Systems

SAP, a widely-used, third-party enterprise software application, has been the predominant platform used by PSE&G, its parent, and most affiliates (including PSEG Services Corporation) to perform accounting processes since early 2000. PSE&G's reliance on SAP further increased in April of 2009 when it converted its customer billing and information system from a 30-year-old legacy system to SAP.[11] (The customer information system conversion will be discussed in more detail in the Customer Service chapter of this report.)

Other accounting-related software applications used by PSE&G include Hyperion Enterprise for financial reporting and legal consolidation and Cognos for planning.[12] In addition, the Internal Audit Department uses an IBM-tailored enterprise content management system to track the company's compliance with Sarbanes-Oxley.[13]

[11] Responses to Discovery, OC-56 and OC-346.
[12] Response to Discovery, OC-56.
[13] Interview with William Metzger, Vice President – Internal Auditing Services, and Steven Beckenstein, Manager – Internal Auditing Services, on July 7, 2010.

With respect to SAP, it is considered by the company to be a strategic application, and no replacement for it has been either planned or identified.[14]

Performance Metrics

The company measures internal performance through the use of balanced scorecards. Balanced scorecards have been in place for utility operations since approximately 2003. They were implemented for PSEG Services Corporation and unregulated operations beginning in 2008. The targets in balanced scorecards are designed to achieve top quartile performance when reliable benchmarking data is available[15] or continuous improvement when such information is lacking.[16] With respect to the last criteria mentioned, management encourages the use of stretch targets. Paraphrasing one manager, "if your department is able to meet all of its targets, they are not set high enough."[17]

The focus of the balanced scorecards has evolved over time. In 2008, performance measurements fell into one of four categories – People, Customer Care, Operations, and Financial. The four categories used by the company in 2009 were:[18]

- People
- Safe, Reliable
- Economic
- Green Energy

The following is the balanced scorecard performance for three of the accounting-related departments within the CFO organization in 2008 and 2009:[19, 20]

[14] Response to Discovery, OC-430.
[15] Top decile for safety-related performance (see response to Discovery, OC-150).
[16] Interviews with Ralph Izzo, Chairman, President and CEO, on December 7, 2010 and Bill Nash, former Manager – Business Process, Standards & Analysis, on August 20, 2010.
[17] Interview with Derek DiRisio, Vice President and Controller on July 8, 2010.
[18] Response to Discovery, OC-999.
[19] Internal Auditing Services reported to the Executive Vice President & General Counsel prior to Caroline Dorsa's hiring as CFO in April of 2009.
[20] A more detailed description of each metric is provided in response to Discovery, OC-998.

[Begin Confidential]

Table 12-2 – Accounting Services (Controller's Department) - Balanced Scorecard Results

Accounting Services (Controller's) Department Balanced Scorecard Results			
Description	Target	Actual	Performance
[redacted]			

Table 12-3 - Finance - PSE&G Department - Balanced Scorecard Results

Finance – PSE&G Department Balanced Scorecard Results			
Description	Target	Actual	Performance
[redacted]			

Table 12-4 - Internal Auditing Services Department - Balanced Scorecard Results

Internal Auditing Services Department Balanced Scorecard Results			
Description	Target	Actual	Performance
[redacted]			

[End Confidential]

Although no definitive trend can be ascertained from only two years of data, observations worth noting include:

- With few exceptions, the goals associated with "People" which encourage safe, motivated, and productive employees were achieved for all departments disclosed above. However, because the use of balanced scorecards is relatively new for PSEG Services Corporation, it is not known whether these positive results are due to goals which have been set too low or a concerted effort by management to achieve them.

- Of the three departments presented above, Internal Auditing Services is not only achieving a high rate of its performance metrics but uniquely "has set the bar higher" for all metrics carried over from 2008 to 2009.[21]

- Although it appears that the Accounting Services Department relaxed its targets on the financial closing process between 2008 and 2009 (and failed to meet them in both years), the company attributes the former to a change in the way that a separate Accounting organization in Texas was handled from year to year.[22]

With respect to the last item listed above, management assesses the quality of the financial closing process by reviewing the number and, more recently, the magnitude of the adjustments that must be made to the accounting records after the initial close but prior to the issuance of external financial statements. In 2009, the most significant of these adjustments involved PSE&G affiliates rather than the utility.[23] The likelihood that these errors or omissions will affect PSE&G in the future is unknown.

[Begin Confidential]

[End Confidential][24]

[21] Targets in 2009 were either the same or more difficult than the targets in 2008, <u>and</u> the targets in 2009 were either the same or more difficult that the actual results achieved in 2008.

[22] According to informal correspondence received from the company on August 29, 2011; 2008 targeted and actual amounts for the Accounting Services Department excluded adjustments associated with Texas plants because a separate organization was responsible for the accounting of these plants. After the Accounting Services Department assumed responsibility for the accounting of Texas plants in 2009, the targeted adjustment amount was increased for the Accounting Services Department. Although a separate break-out of targeted amounts is not available just for the Texas plants, the company asserts that the total actual adjustments in both years remained steady at 49 (2008: 37 associated with the Accounting Services Department and 12 associated with the Texas plants; 2009: 49 associated with the Accounting Services Department which includes the Texas plants).

[23] Response to Discovery, OC-1377.

[24] Response to Discovery, OC-57 **[Begin Confidential]** **[End Confidential]** (Restricted On-Site Only).

The Internal Audit Service Charter calls for an external assessment of the organization to be carried out at least once every five years.[25] The most recent assessment was performed by PricewaterhouseCoopers (PwC) in 2007.[26] The overall conclusion reached at that time was that Internal Audit Services **[Begin Confidential]**

[End Confidential][27] When asked to provide a status update on the implementation of these recommendations, PSEG noted that the following were still in progress in mid-2010:[28]

- Recommendation: Consider enhancements to the human resources model for IAS, such as formal career development planning and/or rotation programs. Status: Other priorities have precluded completion, but management has commenced discussions regarding a rotation program.

- Recommendation: Continue to expand technology in the IAS process, specifically implement an automated workpaper application. Status: Although IAS has selected Teammate as its preferred tool, budget cutbacks have delayed implementation until 2011 or later.[29]

Benchmarking

Besides the **[Begin Confidential]** **[End Confidential]**, the following benchmarking studies were made available to us: [30]

[Begin Confidential]

[End Confidential]

2007 AP Department Benchmarks and Analysis **-** According to the company, it did not provide data or otherwise participate in the IOMA Accounts Payable benchmarking study. Instead, it purchased the

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[25] Response to Discovery, OC-375.

[26] Interview with William Metzger, Vice President – Internal Auditing Services, and Steven Beckenstein, Manager – Internal Auditing Services, on July 7, 2010.

[27] Response to Discovery, OC-580 (p. 6 of 30) (Restricted On-Site Only).

[28] Response to Discovery, OC-1015.

[29] Per the 2010 Global Audit Information Network benchmarking study, 54 percent of gas and electric utilities and 63 percent of Edison Electric Institute participants employ electronic workpaper software (see response to Discovery, OC-1014, p. 106 of 173).

[30] Response to Discovery, OC-57 (Restricted On-Site Only). However, we were denied access to one benchmarking study that addressed utility accounting matters on the grounds that it was a consultant's proprietary study (response to Discovery, OC-1023). In addition, audit work programs obtained from the Edison Electric Institute Internal Auditing Committee which will be incorporated into PSEG's Internal Audit group's practices were also withheld because of legal arrangement (response to Discovery, OC-581).

results for price comparison purposes only. The one statistic that PSEG disclosed to us regarding its own Accounts Payable operation was price per invoice, which ranged from $2.43 to $2.52 during the years 2008, 2009, and 2010. This compares to top quartile performance per IOMA of $3.41.[31]

2008 Payroll Performance Study[32] - **[Begin Confidential]**

[End Confidential]

PSEG management attributes it relatively high payroll processing costs to the following:[33]

- PSEG asserts that it classifies certain costs as payroll processing in nature that top performers do not. An example of this is costs associated with its employee call center that handles non-strategic human resources issues in addition to payroll, unlike the study's top performers.

- PSEG points out that top performers utilize bi-weekly pay while PSEG is contractually bound through certain union agreements to pay on a weekly basis. All other things being equal, more frequent payrolls lead to higher processing costs. A proposal to adopt bi-weekly pay is expected to be presented in the next contract negotiation.

- At the time of the study, only 28 percent of PSEG employee had chosen to receive electronic pay advices. Since that time, participation has increased to 80 percent, which has resulted in annual savings of over $150,000.

- PSEG notes that the State of New Jersey does not allow less- costly, mandatory payroll direct deposit while the study's top performers have generally instituted such programs. The printing and mailing of over 800 paper checks per week and the additional costs of union-required off-

[31] Response to Discovery, OC-1141.
[32] Response to Discovery, OC-57 (Restricted On-Site Only).
[33] Response to Discovery, OC-1138.

cycle payments likely puts PSEG at a distinct disadvantage when comparing costs to top performers.

- Except in limited circumstances, PSEG has not adopted employee self-service data maintenance. 43 percent of top performers have. PSEG is currently evaluating the adoption of this offering.

- Tax filings were only filed electronically 10 percent of the time by PSEG when the survey was originally administered. Now, PSEG has increased the use of electronic filing to 46 percent of the time. PSEG also recently began electronic presentment of child support orders in Pennsylvania and New Jersey, replacing the manual submission of paper checks and attachments that was employed at the time of the survey.

- PSEG has subsequently adopted some automation related to relocation expense payments and stock options that was not considered in the survey.

While PSEG may be prohibited from pursuing some cost savings strategies because of contractual agreements or restrictions imposed by the state, we encourage them to pursue those that are not prohibited and make sense from a cost-benefit perspective. Of those listed above, the adoption of employee self-service data maintenance appears to have the most promise **[Begin Confidential]** **[End Confidential]**[34]

Finally, with respect to the department's staff mix, PSEG management suggests that the SAP software used by the company to process payroll is more complex than payroll software used by the top performers in the survey. As a result, PSEG needs a higher mix of professionals to administer its payroll.[35] We did not attempt to independently verify this assertion.

2010 Internal Audit Benchmarking Study – The study conducted by the Global Audit Information Network included numerous comparisons. Some of the highlights were:[36]

- PSEG's internal audit costs per auditor exceeded by a substantial amount costs incurred by its peers. A review of the raw data indicates that this is due to higher than normal wage and benefit costs, overheads, and allocations.

- PSEG internal audit management had nearly twice the level of experience in the profession and industry (as measured in years) as its peers.

- PSEG's internal audit staff had a higher percentage of professional designations than its peers.

- Compared to its peers, the Internal Audit group performed substantially fewer audits during the year reported.

[34] Response to Discovery, OC-57 (Restricted On-Site Only).
[35] Response to Discovery, OC-1140.
[36] Response to Discovery, OC-1014 (pp. 23, 29, 42, 44, 85, 94, 107, and 145 of 173).

- Unlike its peers, PSEG does not prepare a multi-year audit plan.[37]

- Unlike its peers, PSEG does not highlight repeat findings in its audit reports.[38]

[Begin Confidential]

[End Confidential][39]

[Begin Confidential]

[End Confidential][40]

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[37] However, according to the company's response to Discovery, OC-1015; Internal Audit did develop a five-year strategic plan in 2008.

[38] However, a review of quarterly reports sent by Internal Audit to the Chair of the Audit Committee and copied to the Chairman & CEO and Executive Vice President &C CFO indicates that repeat audit findings are tracked and reported (see response to Discovery, OC-1008). We also observed at least one instance in which a repeat finding was highlighted in an audit report (February 27, 2008 Audit Report concerning PSEG Escheat Process provided informally by the company).

[39] Response to Discovery, OC-57 (Restricted On-Site Only).

[40] Response to Discovery, OC-57 (Restricted On-Site Only).

Internal Controls

Overview

Internal control is the process designed by an organization to provide reasonable assurance that its operations are effectively and efficiently conducted, its financial reporting is reliable, and its compliance with applicable laws and regulations is achieved. To realize these objectives, PSEG has adopted the structural blueprint developed by the Committee of Sponsoring Organizations of the Treadway Commission, an accounting industry-backed organization formed in the mid-80's.[41] The inter-related components of this framework are the control environment, risk assessment, control activities, information and communication, and monitoring.

In its 2007 Standards of Integrity, PSEG described the purpose of its system of internal controls as providing reasonable assurance that:[42]

- Financial and operational accounting and reporting are full, fair, accurate, timely and reliable;
- Authority and accountability to conduct business decisions is delegated in a manner that balances efficient decision-making with protection of PSEG's assets and interests;
- Adequate segregation of duties exists between authorization, creation, approval, custody, record keeping and reconciliation;
- Fraud and misconduct are prevented and detected;
- Compliance with PSEG's policies and practices and applicable laws and regulations is promoted, communicated and maintained;
- Financial integrity remains strong and risk is effectively managed;
- Assets are used in PSEG's best interest and are appropriately safeguarded and accounted for; and
- Operations and activities are effective and efficient.

On an annual basis, management must report on the internal control over financial reporting in which it acknowledges that it ". . . is responsible for establishing and maintaining effective internal control . . . and for the assessment of the effectiveness of internal control . . ." As of year-end for the years 2007, 2008, and 2009, management concluded that PSEG's and PSE&G's internal controls over financial reporting were effective. The external auditor concurred with this assessment as it relates to PSEG for all of these years. Pursuant to temporary rules of the Securities and Exchange Commission, management's report on PSE&G's internal control over financial reporting for these three years was not subject to attestation by the external auditors.[43]

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[41] Response to Discovery, OC-372, p. 11 of 13.
[42] Response to Discovery, OC-77, p. 19 of 49.
[43] PSEG 2007 Form 10-K (pp. 177, 179, and 180), PSEG 2008 Form 10-K (pp. 180, 182, and 183), and PSEG 2009 Form 10-K (pp. 183, 185, and 186).

Internal Auditing Services

Although it is all employees' responsibility to comply with the company's internal controls, the group primarily responsible for monitoring this compliance is the Internal Auditing Services organization. Currently, Internal Auditing Services consists of both the conventional Internal Audit department and the group that is responsible for the administration of Sarbanes-Oxley compliance (the Internal Controls group). The latter was subsumed by Internal Auditing Services in June, 2009 after previously reporting to the Vice President – Risk Management.[44] Internal Auditing Services is currently headed by its vice president, William Metzger who assumed this position in March, 2010 after previously serving as Assistant Controller of PSEG Power.[45]

Historically, Internal Auditing Services has devoted the vast majority of its time to internal audits and Sarbanes-Oxley support activities. Statistics from 2005 through 2007 show that department employees devoted between **[Begin Confidential]** **[End Confidential]**[46] Other responsibilities of Internal Auditing Services include, but are not limited to:[47]

- Compliance Program Investigations – research and investigations into alleged violations of PSEG's Standards of Integrity as directed by PSEG's General Compliance Counsel. (Items of interest are generally reported through the Integrity Line, Certifications of Compliance, and anonymous letters.)

- Special Control Reviews – management requests to conduct consulting engagements that focus on the examination of systems and processes during design and development stages for the purpose of establishing adequate internal controls or that provide control guidance on an ad hoc basis for management-perceived concerns.

- Continuous Monitoring Routines – "real time" evaluations of internal controls using technology-assisted programs.

A review of Audit Committee minutes indicates that this group is kept apprised of all facets of the Internal Auditing Services organization's activities, including internal audits and Sarbanes-Oxley testing. In addition, Mr. Metzger meets with the Audit Committee in executive session when management is not in attendance.

Internal Audit Group – **[Begin Confidential]**

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[44] Response to Discovery, OC-1050.

[45] Interview with William Metzger, Vice President – Internal Auditing Services, and Steven Beckenstein, Manager – Internal Auditing Services, on July 7, 2010.

[46] Derived from response to Discovery, OC-579 (Restricted On-Site Only).

[47] Response to Discovery, OC-370.

[End Confidential][49]

As noted in the discussion of performance metrics, Internal Audit completed over 97 percent of the audits planned in 2008 and 2009. These audits included, but were not limited to, the following:[50]

- Customer Operations – Customer Refund Process
- Customer Operations – PSE&G Metering
- Customer Operations – PSE&G Revenue Integrity Process
- Customer Operations – PSE&G Large Customer Support
- Customer Operations – Solar Loan Programs
- Delivery Operations – Basic Gas Supply Service Activities
- Delivery Operations – Material Control
- Delivery Operations – Delivery Projects & Construction (Selected Transmission Projects)
- Finance – PSEG Accounts Payable Process
- Finance – PSEG Officers' Travel and Entertainment Expenses
- Finance – Local Cash Management Process
- Finance – Intercompany Billing
- Finance – Balance Sheet Reconciliation Process
- Finance – Fixed Asset Accounting Process
- Finance – Deferred Assets

In reporting on the results of an audit, Internal Audit opines on the key controls being tested. Opinions are characterized as either "adequate" which means that no significant control weaknesses were identified; "adequate, except for" which indicates that one significant control weakness and/or extensive noteworthy issues were identified; or "inadequate" which means that more than one significant control weakness was found. Significance in this context is a function of probability of occurrence, materiality, and potential public sensitivity.[51]

[48] **[Begin Confidential]**

[End Confidential] (see response to Discovery, OC-1014 (p. 76 of 173)). In addition, the Internal Audit Services Charter states that the annual plan will be submitted to executive management and the Audit Committee for review and approval (see response to Discovery, OC-375). However, we saw no evidence of approval in the review of Audit Committee meeting minutes, and the Audit Committee Charter dated December 15, 2009 is silent on the matter.

[49] Response to Discovery, OC-383 (Restricted).

[50] Response to Discovery, OC-10.

[51] Responses to Discovery, OC-371 (pp. 23-24 of 50) and OC-620 (Restricted On-Site Only).

Opinions rendered by PSEG's Internal Audit group between 2007 and 2009 were as follows:

[Begin Confidential]

Table 12-5 - Internal Audit Report Results

Internal Audit Report Results			
Classification	2007	2008	2009
[redacted]			

[End Confidential]

[52] Response to Discovery, OC-620 (Restricted On-Site Only).

Management is required to provide a formal status within 90 days of all significant findings associated with "except for" or "inadequate" audit reports. Beginning in 2008, Internal Audit validates the actions that management has represented will remediate such findings. This must take place within 90 days of management's final status report. As of June 30, 2010, the company asserts that corrective action and Internal Audit validation (post-2007) have taken place for all exceptions but for the one related to approval automation of manual non-purchase order checks. Remediation of this exception has been postponed due to budget constraints.[53] This control weakness was originally identified by Internal Audit in an audit report dated **[Begin Confidential]** **[End Confidential]**[54]

More recently, Internal Audit has noted the following significant exceptions in audit reports either directly or indirectly associated with PSE&G:[55]
[Begin Confidential]

[End Confidential]

Because of the timing of the release of these 2010 internal audit reports, i.e., during May and June 2010, all but some of the deficiencies associated with the credit and collection process were still unresolved as of June 30, 2010.[56]

Although <u>no</u> members of the Audit Committee of the PSEG Board of Directors are included on the distribution list of the audit reports that have noted exceptions, we were told by at least one member of the Audit Committee that they are provided these reports on a quarterly basis.[57]

<u>Internal Controls Group</u> – The Internal Controls group (2 employees) reports to William Metzger, Vice President – Internal Auditing Services.[58] This group is tasked with ensuring that the company complies with Sarbanes-Oxley, especially as it relates to the requirement concerning management's assessment of internal controls (Section 404).

[53] Response to Discovery, OC-1013.
[54] Response to Discovery, OC-620 (p. 58 of 67) (Restricted On-Site Only).
[55] Response to Discovery, OC-1012 (Restricted).
[56] Response to Discovery, OC-1013.
[57] Responses to Discovery, OC-620 (Restricted On-Site Only) and OC-1012 (Restricted) and interviews with members of the Audit Committee of the PSEG Board of Directors.
[58] Response to Discovery, OC-1270 (p. 109 of 116).

As we have previously noted, both PSEG and PSE&G issued reports indicating that internal controls over financial reporting were effective in each of the three years ended December 31, 2007, 2008, and 2009. In reaching this conclusion, management relied upon the work overseen by the Internal Controls group that was based on a comprehensive testing program.

The testing of internal controls begins with the identification of the applicable controls and a determination of their importance. The company provided us a list of 73 controls determined by management to be most critical in ensuring that financial results are properly disclosed as it relates to the functional areas of accounts payable, accounts receivable, payroll, and property accounting.[59]

[Begin Confidential]

[59] Response to Discovery, OC-82.

Table 12-6 - Sarbanes-Oxley Testing Results

Sarbanes-Oxley Testing Results			
Description	2007	2008	2009 (A)
[redacted]			

[redacted] **[End Confidential]**[60] None of the deficiencies existing at year-end 2009 were carried over from previous years.[61] According to the company, the 2009 control deficiencies involved:[62]

- Hedging effectiveness that was compromised because incorrect regression files were used.
- Retired assets that were not always reported to the Accounting Department.
- An ineffective review of the reconciliation of current and non-current deferred income taxes that did not identify a typographical error.
- Lack of approvals involving Enterprise Risk Management confirmations.

All four of these control deficiencies were remediated prior to mid-2010.[63]

[60] Response to Discovery, OC-574 (Sarbanes-Oxley 404 Compliance Updates dated July 15, 2008 and February 16, 2010) (Restricted On- Site Only).
[61] Response to Discovery, OC-1021.
[62] Response to Discovery, OC-1020.
[63] Interview with Derek DiRisio, Vice President and Controller on July 8, 2010.

Other Accounting Matters

Management Letters – Historically, external auditors have provided management with recommendations for process or system improvements that were identified while conducting the financial statement audits. These recommendations were communicated in management letters. Since the advent of Sarbanes-Oxley, this practice has been discontinued and replaced with the Report of Independent Registered Public Accounting Firm filed with the company's Form 10-K.[64] These publicly disclosed reports are not nearly as illuminating as the typical management letter, and we noted nothing of significance in the auditors' filings for 2007, 2008, or 2009.

Exploration of the Potential for Accounts Payable Outsourcing - In August 2010, PSEG released a request for proposal (RFP) to outsource its Accounts Payable and Disbursements Services. The services requested to be provided include mail handling, vendor database and maintenance, invoice processing (both with and without purchase orders), recurring payments, business expense reimbursement, purchasing card administration, fleet card administration, payroll taxes, payment process and remittance advice, vendor inquiry and problem resolution, imaging and document retention, Sarbanes-Oxley compliance, and financial reporting. The key performance requirements incorporated in the RFP included specific expectations concerning the timeliness of responses to voicemails and the continued compliance with Sarbanes-Oxley requirements.[65]

PSEG management ultimately concluded that the company would not be outsourcing at this time. They continue to explore opportunities to improve efficiency and cost structure both internally and externally as they arise.[66]

Potential Rotation of External Auditors – Deloitte & Touche LLP (Deloitte & Touche) and its predecessor companies have performed the financial statement audits of PSEG and its subsidiaries since 1973. While PSEG has not solicited competitive bids for these financial statement audits during this timeframe, the Audit Committee considers and affirms the selection of the external auditor subject to ratification by the company's stockholders every year.[67]

[64] Response to Discovery, OC-12.
[65] Response to Discovery, OC-1135 (Supplemental).
[66] Informal communication with PSEG personnel on March 7, 2011.
[67] Response to Discovery, OC-572. Around the time of the proposed merger with Exelon in 2005, Exelon's external auditor approached PSEG to discuss the possibility of being PSEG's external auditor in the future.

Even though competitive bidding is not being used, according to management, the company has been very aggressive in negotiating its audit fees in recent years. That seems to be borne out in the total audit fees incurred by the company over the past four years:[68]

- 2006 - $7,517,543
- 2007 - $6,849,675
- 2008 - $6,059,093
- 2009 - $5,820,000

Company management also feels that in addition to the reduction in audit fees, the company has received a substantial improvement in the quality of service provided from its auditors.[69]

Sarbanes-Oxley does not require mandatory rotation of auditing firms. It does, however, require rotation of the lead engagement partner every five years (Section 203). During our review, we noted that the Lead Client Service Partner for Deloitte & Touche was replaced in early 2008 to specifically comply with this Sarbanes-Oxley rotation requirement.[70]

With respect to voluntary external audit firm rotation, management and members of the Board of Directors indicated that the benefits of retaining Deloitte & Touche as external auditor (such as having staff that is familiar with the company, avoiding "learning curve" costs with another firm, and doing business with a firm viewed as preeminent in the industry) outweighed the potential benefits of switching to a new firm that might have a fresh perspective on the company's financial disclosures.[71] Given the intense scrutiny that public financial disclosures are under currently, we agree.

Asset Impairments – While different asset classes have their own unique rules, in general, entities record impairments (or "write down" the value) of assets when the values assigned to them for financial statement reporting purposes would otherwise exceed their fair value. Because of this, the existence or non-existence of asset impairments may indicate the quality of past decisions made by management. For example, an entity that significantly over-pays for a business will ultimately have to recognize an impairment when future cash flows do not justify the value placed on the underlying assets and/or liabilities. While it is possible that favorable macroeconomic conditions can temporarily mask an otherwise poorly conceived or executed decision, over long periods of time, they are likely to result in impairments if the amounts involved are significant.

[68] PSEG Proxy Statement filed March 5, 2008 (p. 47), PSEG Proxy Statement filed March 16, 2009 (p. 44), and PSEG Proxy Statement filed March 8, 2010 (p. 54).

[69] Interview with Derek DiRisio, Vice President and Controller on July 8, 2010.

[70] Audit Committee meeting minutes dated February 19, 2008.

[71] Interviews with Derek DiRisio, Vice President and Controller on July 8, 2010 and various members of the Board of Directors.

Since the beginning of 2007, PSE&G has not tested for nor recorded any asset impairments.[72] In addition, according to the company, PSEG Power and PSEG Services Corporation have not recognized any asset impairments for the years 2007, 2008, and 2009.[73]

However, Energy Holdings (a PSE&G affiliate) did record several asset impairments during the time period from the beginning of 2007 to late 2009. These included $7 million recorded in both 2007 and 2008 on investments held in Venezuela; $2 million and $9 million recorded in 2007 and 2008, respectively, on investments held in India; and $3 million recorded in 2009 on an equity method investment in GWF Energy LLC. These amounts do not include the $355 million after-tax charge recorded by the company on its leveraged lease portfolio in 2008 or losses sustained as a result of sales of foreign interests.[74] Although the recorded impairments are material to Energy Holdings, they are not significant to the consolidated PSEG earnings in any of these years.

With that being said, Energy Holdings' liquidity is unaffected by the impairments it is currently recording. These impairments are non-cash charges that negatively impact earnings but have no effect on the current cash flow of the subsidiary. And as we note in our discussion of the company's finances, there is little evidence to suggest that PSE&G operations are being used to subsidize non-regulated affiliates such as Energy Holdings.

[72] Responses to Discovery, OC-44 and OC-1007 and interviews with Derek DiRisio, Vice President and Controller on July 8, 2010 and Daniel Furlong, Assistant Controller – PSE&G on July 7, 2010. The most recent information provided on this subject was received in July, 2010.

[73] Response to Discovery, OC-44 and PSEG 2009 Form 10-K (pp. 107-108).

[74] Response to Discovery, OC-44. We did not attempt to reconcile the amounts reported by the company to us in discovery to publicly-disclosed financial statements.

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13. Power Supply Management

This Chapter addresses PSE&G's power supply function, including power supply planning and BGS power procurement. PSE&G also purchases power under legacy Non-Utility Generation (NUG) contracts. NUG purchases are addressed in Chapter 15.

Demand response, energy efficiency and renewable generation are addressed in Chapter 14. Power procurement affiliate relations issues are addressed in Chapters 16 and 17.

Summary of Findings

1. PSE&G paid $3.0 billion for BGS-FP (Basic Generation Service - Fixed Pricing) power in 2009. PJM energy and capacity prices directly impact BGS prices. PJM market rules and transmission planning decisions have a significant impact on BGS prices.

2. The full requirements component of BGS-FP prices increased from $21 per MWH in 2005 to $48 per MWH in 2011. The implementation of the RPM accounts for approximately 60 percent of that increase.

3. Energy prices in PSE&G's transmission zone were fifteen percent higher than the PJM average in 2010 because of transmission constraints that limit the ability to import lower priced power into PSE&G's zone.

4. Future PJM power prices are subject to considerable uncertainty. New and revised environmental rules are expected to result in the retirement of large amounts of generating capacity. Other uncertain factors include federal and state regulatory policies, fuel prices, economic growth, generation construction costs, demand response, energy efficiency and renewable energy development.

5. Regional Transmission Organizations, such as PJM, produce significant benefits for consumers compared to the alternative of separate control zones for each utility-owned transmission system. PJM estimates regional dispatch and transmission planning produce savings of $2.50 per MWH.

6. High prices and concerns about wholesale power markets have halted the trend towards generation deregulation in the United States. Retail choice has been implemented in fifteen states and the District of Columbia. The northeast of the USA contains thirteen of the fifteen states with retail competition these states belong to PJM, NYISO, or ISO-NE. No additional states have adopted electric industry restructuring since the California energy crises in 2000 and 2001. There is no movement towards generation deregulation in any of the other 35 states.

7. Power supply management should be a priority for PSE&G based on the current environment for generation and commodity procurement.

8. PSE&G's overall power supply strategy is to: (1) purchase default supply in BGS auctions; (2) sell the power it buys under NUG contracts into PJM markets; and (3) comply with BPU directives concerning demand response, energy efficiency and renewable energy.

9. PSE&G's BGS-FP power supply objectives are to: (1) purchase power at prices consistent with competitive markets; (2) provide a modest level of price stability; and (3) protect the company against BGS supplier defaults.

10. PSE&G is opposed to using long-term contracts and utility-owned generation for BGS power supply. PSE&G views those as uneconomic state intervention into competitive markets. PSE&G also opposes PJM's economic transmission planning process.

11. Assuming a transition to alternative generation options, PSE&G's current power supply planning function is not adequately staffed. The Energy Acquisition Group (EAG) is a regulatory and contract management group, not a power supply planning group. The EAG does not have the staffing needed to identify and assess least-cost power procurement strategies. PSE&G's Transmission Business Strategy Group does not have the staffing needed to independently analyze PJM market rules and promote the interests of BGS-FP customers at PJM or FERC. PSE&G's economic transmission planning function is not adequately staffed.

12. PSE&G does not currently prepare power supply plans or engage in integrated resource planning. PSE&G does not adequately analyze market conditions or power supply alternatives. PSE&G does not currently undertake any meaningful analysis of power supply planning issues.

13. The TBSG is included in the Electric Delivery balanced scorecard. That scorecard does not include any goals pertaining to power supply.

PSE&G Power Purchases

PSE&G paid $3.5 billion for power in 2009, as shown in the following table.

Table 13-1 - PSE&G Power Purchases Year 2009

PSE&G Power Purchases Year 2009 - Dollars in Millions	
Type	Cost
BGS - FP	3,046
BGS - CIEP	94
NUG	375
Total	3,515

Source: Response to Discovery, OC- 946 and OC-445
Note: CIEP - Commercial and Industrial Energy Pricing

PSE&G sells the power it purchases under its NUG contracts to PJM.[1] PSE&G's purchased power costs equaled 69 percent of its total electric operating revenues in 2009.[2] PSE&G recovers all of its purchased power costs through formula rates that pass the costs on to customers, net of NUG resale revenues.

PSE&G's distribution customers have the option of purchasing electricity from PSE&G or directly from third party retail (TPR) suppliers. The TPR suppliers are responsible for procuring the power they sell to PSE&G distribution customers and arranging for the delivery of the power to PSE&G's distribution system. TPR suppliers provided approximately 39 percent of the energy delivered to PSE&G distribution customers in 2010.[3] Four TPR suppliers accounted for 67 percent of the TPRS deliveries in 2009.[4]

The customers who do not elect a TPR supplier purchase power from PSE&G under the utility's Basic Generation Supply (BGS) tariff.[5] Residential customers received 99 percent of their energy deliveries under the BGS-FP tariff in 2010. Residential customers accounted for 53 percent of PSE&G's BGS-FP deliveries in 2010.[6]

The following table shows PSE&G's sources and dispositions of energy in 2009.

Table 13-2 - PSE&G Sources and Dispositions of Energy 2009

PSE&G Sources and Dispositions of Energy 2009 - MWH		
Description		MWH
Sources		
	BGS Purchases	30,728,949
	NUG Purchases	41,65,670
	TPRS Load Obligation	13,267,050
	Total Sources	48,161,669
Dispositions		
	Sales to BGS Customers	29,270,631
	Deliveries to TPRS Customers	12,565,919
	Resale of NUG Power	4,165,670
	Line Losses and Other	2,159,449
	Total Dispositions	48,161,669
Source: PSE&G 2009 FERC Form 1, pages 311 and 327; and Response to Discovery, OC-682 and 683.		

[1] PSE&G's NUG contracts are addressed in Chapter 15.
[2] PSE&G 2009 FERC Form 1 Report, page 115.
[3] Response to Discovery, OC-1438.
[4] Response to Discovery, OC-683.
[5] PSE&G Tariff Sheets 75 and 82. The BGS -Fixed Pricing (FP) tariff provides a seasonally adjusted fixed price for residential and small commercial customers. The BGS - Commercial Industrial Energy Pricing (CIEP) tariff provides hourly variable spot market pricing for large commercial and industrial customers.
[6] Response to Discovery, OC-1478.

BGS Overview

PSE&G purchases power for its BGS customers through contracts with BGS suppliers. The BGS-FP contracts have a three year term. The BGS-CIEP contracts have a one year term.

The BGS contracts are competitively bid in annual auctions that are closely supervised by the BPU. The annual auctions are conducted in February of each year for delivery beginning in June. Each auction includes approximately one third of the utility's total BGS-FP load. PSE&G's BGS-FP supply for a given month consists of three equal sized vintages of contracts. For example, during the month of August 2009, the BGS-FP supply consisted of equal amounts of power procured in the February 2007, 2008 and 2009 auctions.

The contract laddering increases price stability. Only one-third of the supply requirements are brought to market at any one point in time, reducing the impact of temporary market conditions on the prices seen by BGS-FP customers. During any given year, the average forward contracted period is about 19 months.[7]

The BGS-FP contracts are for a full-requirements product. The suppliers are responsible for procuring the energy, capacity, ancillary services and transmission needed to serve a specified percentage of PSE&G's overall BGS-FP load.[8] BGS power is priced at a fixed dollars per MWH amount for the three year life of the contract.[9]

The following table shows the prices from the past eight BGS auctions.

Table 13-3 - PSE&G BGS-FP Auction Prices 2004 to 2011 Auctions

PSE&G BGS-FP Auction Prices 2004 to 2011 Auctions	
Auction Date February	Price per MWH
2004	55
2005	65
2006	103
2007	99
2008	112
2009	104
2010	96
2011	94
Source: BGS auction website.	

BGS-FP prices peaked in 2008. The 2011 price is 16 percent lower than the 2008 price.

[7] Overland calculation based on contract terms.

[8] BGS customers are not assigned to specific suppliers. Instead, the pooled BGS load (MWH) is calculated each hour and each BGS supplier is assigned load responsibility for a set percentage of the BGS load pool.

[9] A seasonal factor is applied in summer months. BGS prices also include adjustments to pass-through transmission rate increases.

PSEG's investor presentations break the BGS price down into two components, the PJM western-hub futures market around-the-clock spot market energy price and the full requirements component. The full requirements component includes:

- Capacity costs;
- Load shape (hourly demand variability);
- Transmission;
- Congestion (location premium);
- Ancillary services;
- Risk Premium; and
- Renewable energy certificate ("REC") costs.[10]

The full requirements component has more than doubled since 2004, as shown on the following table.

Table 13-4 - PSEG Analysis of BGS Prices 2004 to 2011

PSEG Analysis of BGS Prices 2004 to 2011 - Dollars per MWH			
Auction Year	PJM West Forward Price	Full Requirements	PSEG BGS-FP Price
2004	37	18	55
2005	44	21	65
2006	71	32	103
2007	58	41	99
2008	69	43	112
2009	57	47	104
2010	49	47	96
2011	46	48	94
Source: PSEG Presentation to the Financial Community, March 7, 2011, page 69.			

According to PSEG, the reasons for the full requirements increase are: [11]

- The implementation of the RPM capacity market in June 2007;
- Increased REC requirements;
- Transmission rate increases;
- Increased credit costs; and
- Increased market risk.

[10] See Chapter 14. New Jersey's renewable portfolio standards require LSEs to purchase renewable energy certificates.

[11] Robinson interview and PSEG 2010 EEI Financial Conference Presentation, November 1 & 2, 2010, page 17.

New Jersey's four electric utilities purchased 36 percent of their BGS-FP power supply from PS ER&T in 2009.[12] PSE&G purchased 43 percent of its BGS-FP requirements from PS ER&T in 2009.[13]

PJM Markets

PSE&G's power supply management occurs within the framework of the PJM regional transmission organization (RTO). PJM operates centrally-administered power and transmission markets that span thirteen states and the District of Columbia. The PJM region has a population of approximately 51 million people.[14]

PJM is the independent system operator (ISO) responsible for planning and operating the high voltage transmission system in its region. PJM is regulated directly by the Federal Energy Regulatory Commission (FERC).

PJM market rules and transmission planning decisions have a significant impact on BGS prices. PJM energy and capacity prices directly impact BGS prices because they represent the opportunity cost of serving BGS load. If a generator elects not to serve BGS load, it can sell its power into the PJM energy and capacity markets.

The BGS suppliers are load serving entities (LSEs) within PJM. They pay network integration transmission service rates that compensate PSE&G for the use of its transmission facilities.

PJM Energy Markets

PJM operates two energy markets, the day-ahead market and the real-time balancing market. The prices paid to generators in both markets are determined under a single clearing price regime. Generators submit price bids into the energy markets. PJM ranks the bids from the lowest to the highest, and purchases energy in ascending price ranked order until the system load obligation is met.

All of the generators receive the same price, regardless of their bids. The single clearing price is set equal to the highest bid needed to serve the last increment of load. When energy demand is high, the single clearing price typically reflects the variable production costs of the most inefficient gas peaking unit needed to meet demand.

Energy prices are set by locational delivery area (LDA) when transmission constraints limit the ability to import lower cost energy into the LDA. The constraints sometimes require PJM to purchase energy from plants located within the LDA whose bids are higher than bids submitted by plants located outside of the LDA. That increases the single clearing price in the constrained LDA. The difference between the clearing price in the constrained LDA and the clearing price in the LDA on the other side of the transmission

[12] PS ER&T is PSEG Energy Resources and Trade. PS ER&T is a subsidiary of PS Power.
[13] Chapter 16.
[14] PJM 2009 State of the Market Report, Volume 2, page 1.

constraint is referred to as transmission congestion. The energy prices in the LDAs are referred to as the Locational Marginal Price (LMP).

Energy prices in the PSE&G transmission zone are consistently higher than average, as shown in the following table.

Table 13-5 - PJM and PSE&G Zone Average Energy Prices, Day-Ahead Load Weighted Average

PJM and PSE&G Zone Average Energy Prices Day-Ahead Load Weighted Average ($/MWH) 2006 to 2010			
Year	Total PJM	PSE&G Zone	Ratio
2006	51	58	1.13
2007	58	68	1.17
2008	70	86	1.22
2009	39	44	1.13
2010	48	55	1.15
Source: Volume 2 of the PJM State of the Markets Reports for 2007 (pages 67 and 69), 2009 (pages 78 and 80, and 2010 (page 84) . Ratio is PSEG price divided by PJM average price.			

PJM energy prices are significantly impacted by natural gas prices. The following table compares energy prices for PSE&G's zone to natural gas prices.

Table 13-6 - PSEG Zone Energy Prices versus Natural Gas Prices

PSEG Zone Energy Prices versus Natural Gas Prices Simple Average Day-Ahead Energy Prices ($/MWH) Natural Gas Futures Price - Henry Hub ($ per Million BTU) 2004 to 2010			
Year	Energy Price	Natural Gas Price	Ratio
2004	50	6.2	8.1
2005	69	9	7.7
2006	54	7	7.7
2007	64	7.1	9
2008	80	8.9	9
2009	42	4.2	10
2010	51	4.4	11.6
Note: Ratio is energy price divided by gas price.			
Source: Energy prices are day-ahead simple average for PSE&G zone per PJM State of Market Reports, except 2004 which is real-time simple average price (day ahead not reported); Natural Gas Price per EIA (Energy Information Administration) website, Natural Gas Data page, NYMEX (New York Mercantile Exchange) Contract 1, Henry Hub annual average.			

The energy price / gas price ratio increased significantly between 2004 and 2010. Overland has not analyzed the reasons for that increase.

PJM Capacity Market

The PJM capacity market is named the Reliability Pricing Model (RPM). Under the RPM, the capacity prices paid to generators are set in annual auctions. The auctions cover a one-year delivery period beginning about three years after the auction date.[15] The capacity payments made to the generators are charged to LSEs based on their capacity obligation, which is driven by their transmission demand.

The RPM was implemented in June 2007 to increase generator revenues. PJM concluded that generator compensation in the energy markets was inadequate; and, as a result, the incentive to build new generating plants was inadequate. PJM proposed the RPM to solve the generators' "missing money" problem.[16]

Generators offer capacity resources in annual RPM auctions. The LSEs do not participate in the auction process. The capacity price is set at the intersection of an administratively determined "demand curve" with the supply curve determined by the generator bids.[17]

The RPM demand curve is based on two administratively determined amounts: (1) The levelized cost-of-new-entry (gross CONE) for a combustion turbine plant, net of expected margins from the energy market (net CONE); and (2) the targeted capacity quantity for the LDA.

At points below the targeted reserve margin, the demand curve price point is set at an administratively determined percentage above net CONE. At points above the targeted reserve margin, prices are set at a predetermined percentage below net CONE. Each point on the supply curve reflects the cumulative quantity of capacity bid at or below the indicated price.

RPM prices vary by LDA when capacity imports are limited by transmission constraints.[18] PSE&G is located within PJM's Eastern Mid-Atlantic Area (Reliability) Council Region (EMAAC). The EMACC LDA separated from the rest of PJM in three of the past five RPM auctions because of west-to-east transmission constraints. The PSEG North LDA separated from EMAAC in the auction for the 2012/2013 delivery year.[19]

The EMAAC supply and demand curves from the RPM Auction for the 2013/2014 delivery year are shown below. [20]

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[15] The auction for the delivery period beginning June 1, 2013 was held on May 15, 2010.

[16] PJM's Reliability Pricing Mechanism, Why it's Needed and How it Works, John Chandley, LECG, LLC, March 2008, page 3. This paper was commissioned by PJM and is available on the PJM web-site.

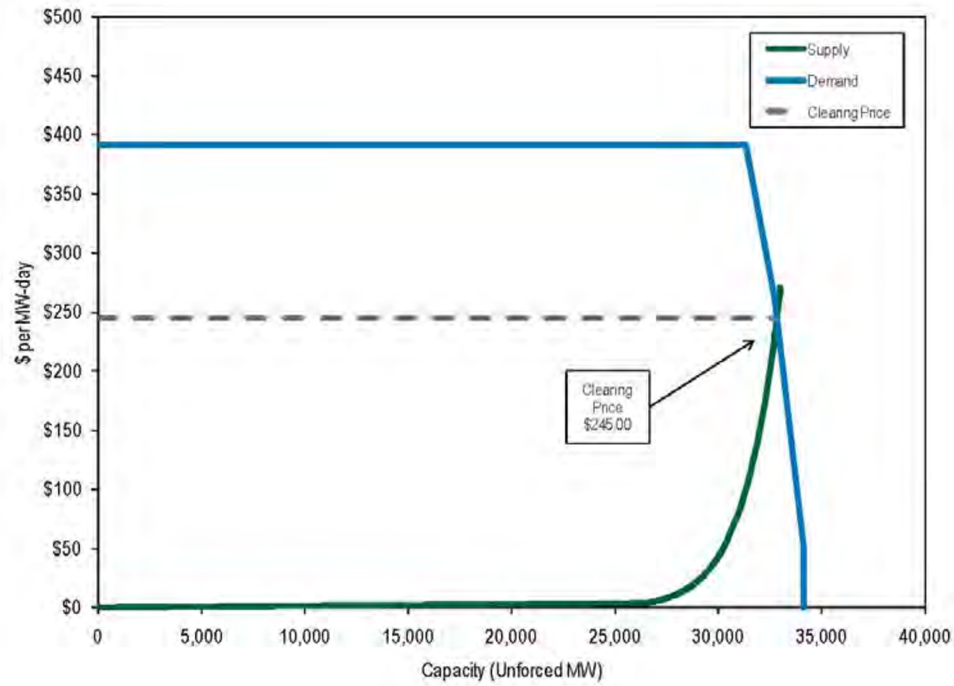
[17] The demand and supply curves are plotted on a graph with price on the vertical axis and quantity on the horizontal axis.

[18] Separate supply and demand curves are plotted for each constrained LDA.

[19] PJM web-site, RPM Users Information, 2012/2013 Base Residual Auction Results Report.

[20] Analysis of the 2013/2014 RPM Base Residual Auction, Revised and Updated, Monitoring Analytics, September 20, 2010, page 43.

Figure 1 - EMAC Market Supply/Demand Curves, 2013/2014 RPM Base Residual Auctions



RPM prices have changed significantly from year to year. The following table shows the prices applicable to generators located within PSEG's transmission zone.

Table 13-7 - RTO and PSEG Zone RPM Prices, Base Residual Auction - Generator Price

RTO and PSEG Zone RPM Prices Base Residual Auction - Generator Price Dollars per MW per Day		
Delivery Year Ending	RTO (Note 1)	PSE&G Zone
May 2008	41	198
May 2009	112	149
May 2010	102	191
May 2011	174	174
May 2012	110	110
May 2013 (Note 2)	16	140
May 2014	28	245

Note 1: RTO price is the price for the unconstrained areas of PJM.
Note 2: Capacity located in the PSEG North sub-zone received a price of $185 in the 2012/2013 Delivery year.
Source: PJM website, RPM base residual auction results.

Each 600 MW of capacity in PSE&G's zone will receive approximately $50 million in RPM capacity revenues during the delivery year ending May 31, 2014.[21]

Market Power Mitigation

Market power is the ability of a market participant to increase or decrease the market price above or below the competitive level. Market power is a serious concern in PJM energy and capacity markets. PJM's market power mitigation rules are critical to protecting consumers from market power abuse. Market power issues are discussed in Chapter 16.

Ownership concentration levels are an indication of market power. The PJM energy markets are moderately concentrated overall and the intermediate and peak markets are highly concentrated.[22] When transmission constraints exist, local markets are created that are significantly more concentrated than the PJM overall energy market.

Market power is endemic in the PJM capacity market. The capacity market is unlikely to ever approach the economist's view of a competitive market structure.[23]

Generation ownership is particularly concentrated in New Jersey and PSE&G's transmission zone. PS Power owns 90 percent of the generating capacity in PSE&G's transmission zone. PS Power owns 33 percent of the capacity in PJM's Eastern Mid-Atlantic Region.[24]

PJM Transmission Planning

PJM is responsible for planning additions to the bulk electric system in its region.[25] The transmission system is owned by the incumbent electric distribution utilities, including PSE&G. The transmission owners are responsible for implementing the projects included in PJM's Regional Transmission Expansion plans (RTEP). PSE&G's role in transmission planning is discussed in Chapter 16.

PJM's 2009 RTEP report cites the following trends as collectively having a "sustained negative impact" on system reliability in New Jersey.[26]

- Growing native load
- Deactivation of existing generation resources
- Sluggish development of new generating resources

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[21] The capacity product sold in the RPM is referred to as unforced capacity. Unforced capacity is installed capacity reduced for expected forced plant outages. The PJM system average forced capacity outage rate assumed for the auction was 6.3%. At that rate the reduction for outages would be 38 MW (6.3% of 600). The generator would receive 562 MW times $245 times 365 days equals $50.25 million.

[22] PJM 2009 State of the Market Report, Volume 2, page 21.

[23] PJM 2009 State of the Market Report, Volume 2, page 309.

[24] Chapter 16.

[25] The PJM bulk electric system is defined as all facilities with a voltage of 100 Kv or higher. PJM web-site, Training, Bulk Electric System Implementation, 2008 System Operator Seminar, page 4.

[26] PJM 2009 Regional Transmission Expansion Plan, February 26, 2010, page 273.

- Continued reliance on transmission to meet load...and access cheaper sources of power from west of New Jersey
- Power Exports to New York City and Long Island

PJM's most recent load forecast was issued in January 2011. The 2011 load forecast is lower than the forecast issued in January 2010 because of downward revisions to economic outlook for the PJM region. The following table shows the percentage change from the prior forecast.

Table 13-8 - PJM 2011 Summer Peak Load Forecast, Percent Change from 2010 Forecast

PJM 2011 Summer Peak Load Forecast Percent Change from 2010 Forecast PSE&G Zone and PJM Mid-Atlantic Region		
Area	2016	2021
PSE&G	-4.5	-5.3
Mid-Atlantic Region	-3.6	-4.2
Note: (4.5) means 4.5 percent reduction from prior forecast.		
Source: PJM Load Forecast Report, January 2011, PJM Resource Adequacy Planning Dept.		

Energy prices are higher in New York City than in Northern New Jersey. Merchant transmission developers have built two lines from PSE&G's service territory to New York City. Those lines export the output of the 645 MW Linden Cogeneration Project and the 512 MW Bayonne Energy Center to New York City.

Construction was scheduled to begin on the Hudson Transmission Project (HTP) in the spring of 2011. The HTP is a 660 MW controllable transmission line from PSE&G's Bergen substation to New York City.[27]

PJM has approved more than $15 billion in transmission enhancements since the inception of the RTEP process in 1999.[28] PJM approved the following backbone transmission lines in the past five years.

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[27] Hudson Transmission Partners web-site. Only 320 MW of the HTP is firm capacity. The remaining 340 MW is treated as an energy only resource. Merchant transmission interconnections are discussed in Chapter 17.

[28] PJM 2009 Regional Transmission Expansion Plan, February 26, 2010, page 3.

Table 13-9 - PJM Regional Transmission Expansion Plans

PJM Regional Transmission Expansion Plans Backbone Projects Approved In Past Five Years		
Name	Route	In Service
TRAIL	Southwest Pennsylvania (502 Junction) to Northern Virginia (Loudoun)	2011
Carson - Suffolk	Southeast Virginia	2011
Susquehanna - Roseland	East Central Pennsylvania to Northern New Jersey	2015
PATH	Southwest West Virginia (Amos) to North Central Maryland (Kemptown).	Suspended
MAPP	East Central Virginia (Possum Point) to Southern Delaware (Indian River)	2015
Branchburg - Roseland - Hudson	Western New Jersey to Northeast New Jersey	Cancelled
Source: PJM 2009 RTEP page 5. In Service dates per BPU LCAPP (Long–Term Capacity Agreement Pilot Program) Agent's Report, Levitan & Associates, March 21, 2011, page 53.		

The Branchburg-Roseland-Hudson project was replaced with a 230 Kv alternative. That alternative project is scheduled for completion in 2015.[29] PJM announced the suspension of the PATH project in February 2011 because load forecast reductions delayed the need for the project.[30]

The RTEP backbone projects were approved based on reliability criteria. Backbone projects can have a substantial impact on energy and capacity prices in PSE&G's zone.

In 2007, PJM estimated that the Susquehanna Roseland line would reduce the energy costs incurred by load serving entities in PSEG's transmission zone by $33 million in 2013.[31]

Market Uncertainty

PJM prices are the result of a complex interrelationship between demand, supply, production costs and market rules. Future PJM price levels are subject to considerable uncertainty.[32]

Uncertain factors include:

- State and Federal Regulatory Policy
- Fuel Prices
- Climate Change and Other Environmental Regulation
- Timing of Generating Plant Additions

[29] Response to Discovery, OC-1322.
[30] Prior to the suspension, the PATH project was scheduled for completion in 2015.
[31] Response to Discovery, OC-1326. When the 2007 estimate was prepared the line was expected to be in service in 2012.
[32] PJM Long-Term Capacity Issues Symposium, Panel 2, Challenges and Uncertainties in an Uncertain Regulatory Environment, Prepared Remarks of Paul Stokiewicz, PJM Senior Economist, January 27, 2010.

- Cost of Financing and Constructing New Generation
- Generating Plant Retirements
- Transmission Expansion
- Demand Response Programs
- Price Responsive Demand and Advanced Meter Reading
- Economic Growth
- Energy Efficiency
- Renewable Energy
- Distributed Generation
- Smart Grid Efficiency Improvements

Environmental requirements are a particularly significant factor. Changes to environmental rules are expected to accelerate the retirement of older fossil-fueled plants over the next ten years. The following changes are expected to have the greatest impact.[33]

- Revisions to Section 316(b) of the Clean Water Act may require the replacement of once-through cooling systems with closed-loop cooling systems.
- New emissions standards for mercury, acid gases, heavy metals and organics under Title 1 of the Clean Air Act may require significant additions of emissions control equipment at existing coal plants.
- New standards for sulfur dioxide and nitrogen oxide (Nox) emissions under the Clean Air Transport Rule may require additions of emissions control equipment.
- New regulations under the Resource Conservation and Recovery Act may increase the cost of coal ash disposal.

The new and revised rules are expected to result in the retirement of large amounts of existing generating capacity. The National Electric Reliability Corporation (NERC) issued a special assessment of the impact of the new rules in October 2010. NERC concluded the environmental rules could result in the loss of as much as 19 percent of the existing fossil-fueled steam capacity in the United States by 2018.[34] NERC's base case forecast shows 46,346 MW of retirements and derates by 2018.[35] PSE&G is located within the Reliability First Corporation (RFC) reliability area. NERC's base case shows 9,813 MW of retirements and derates for RFC by 2018.

The changes are expected to have a significant impact within PJM. The BPU's LCAPP Agent assumed 9,315 MW of coal-fired capacity and 2,259 MW of oil/gas fired capacity would be retired between 2014 and 2019 in its March 2011 analysis.[36]

[33] 2010 Special Reliability Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations, North American Electric Reliability Corporation, October 2010, Page 1.

[34] Steam capacity does not include combined cycle and combustion turbine units. The 19 percent figure includes retirements and derates for increased station load for emissions control equipment at the plants that remain in service.

[35] 2010 Special Reliability Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations, North American Electric Reliability Corporation, October 2010, Page 24.

[36] BPU LCAPP Agent's Report, Levitan & Associates, March 21, 2011, page 50. New Jersey's LCAPP Law is discussed in a subsequent section of this Chapter.

The LCAPP Agent's Report indicates: [37]

> *Focusing on PJM, Brattle Group concluded that 12 GW to 19 GW of coal-fired generation was at risk of retirement by 2020. Credit Suisse found that 25% of coal-fired capacity in PJM (19,553 MW) lacked both scrubbers and SCR.[38] Much of that capacity is at larger plants where economies of scale will help justify the necessary environmental capital expenditures to keep the plants operational. But roughly half of that capacity, 9,841 MW, is at plants with capacities of 300 MW or less, nearly all of which are between 40 and 60 years old. The economic conditions at those plants are much more likely to favor a decision to retire. In addition, 4,865 MW is at small coal-fired plants that currently have SCR but lack scrubbers. These plants will also be at significant risk of retirement. In its base case, Credit Suisse assumed that 12,274 MW of coal-fired generation in PJM would retire between 2013 and 2017.*

The environmental rule changes are also expected to result in the retirement of significant amounts of older oil and gas oil steam capacity within PJM.

Regulatory uncertainties include potential changes in PJM market rules and state default supply polices. The generation industry is facing an operating environment with significant risks. Potential entrants mitigate that uncertainty by waiting for more information before making investment commitments.[39]

Benefits and Challenges in PJM Markets

RTO's produce significant benefits for electricity consumers compared to the alternative of separate control areas for each utility-owned transmission system. PJM estimates that RTO operations produce the following savings for consumers in the PJM region.

[37] BPU LCAPP Agent's Report, Levitan & Associates, March 21, 2011, page 52.

[38] SCR is selective catalytic reduction. SCR reduces NOx levels by combining flue gas with ammonia or urea over catalysts that speed reductions of NOx into nitrogen and water.

[39] PJM Long-Term Capacity Issues Symposium, Panel 2, Challenges and Uncertainties in an Uncertain Regulatory Environment, Prepared Remarks of Paul Stokiewicz, PJM Senior Economist, January 27, 2010.

Table 13-10 - PJM Region, RTO Annual Savings Estimated by PJM

PJM Region RTO Annual Savings Estimated by PJM Dollars in Millions		
Type	Low	High
Reliability - resolving transmission constraints over larger area	78	98
Reliability - transmission planning over larger area	390	390
Generation Investment - reduced generation reserve planning requirements because of diversity of generation resources over larger area	366	900
Demand Response - centralized market for demand response in RPM avoids cost of constructing new generation	275	275
Energy Production Cost - centralized dispatch over larger area	340	445
Grid Services - centralized operating reserve market over larger area	80	105
Total	1529	2213
Source: PJM website, PJM Value Proposition, PJM Efficiencies Offer Regional Savings. January 2011.		

End-use customers in the PJM region purchased approximately 760 million MWH of energy in 2009.[40] The savings claimed by PJM equal approximately $2.50 per MWH.[41]

Barriers of entry for new generation in PJM include: (1) the capital intensive nature of generation; (2) uncertainty concerning future power prices; (3) scarcity of economic sites for new plants; (4) lead time and cost of obtaining environmental and other regulatory permits; and (5) high transmission interconnection costs, including system upgrades. The complexity of PJM's markets and the frequency of changes to market rules also discourage entry by new competitors.

Potential sites for new generation must satisfy environmental requirements and have access to transmission, fuel and water. Existing plants sites are typically the most economic sites for constructing new generation. Most of those sites were originally acquired by regulated electric utilities and transferred to generation affiliates as part of electric industry restructuring. The PJM market monitor publishes a "net revenue adequacy" analysis for various generation technologies in its Annual PJM State of the Markets Reports. The analyses attempts to determine if PJM energy, capacity and ancillary services prices are high enough to justify the construction of new generating plants.

The net revenue analysis determines the contribution to fixed costs provided by PJM market prices in the prior year and compares that contribution to the estimated levelized fixed costs of a new plant. The new plant costs are levelized over a 20 year period and include a market-based return on invested capital.[42]

[40] PJM Load Forecast Report, January 2010, PJM Resource Adequacy Planning Department, page 65.
[41] Average of high and low savings estimates divided by 760 million MWH equals $2.46 per MWH.
[42] 2009 PJM State of the Market Report, Volume 2, page 133.

The net revenues are calculated for each PJM transmission zone. The following table shows the most recent results for the PSE&G zone.

Table 13-11 - PJM Net Revenue Adequacy Analysis, PSE&G Transmission Zone

PJM Net Revenue Adequacy Analysis PSE&G Transmission Zone 2008 and 2010 Percentage of Fixed Costs Recovered by Market Prices			
Technology	2008	2009	2010
Combustion Turbine	70	58	80
Combined Cycle	107	64	96
Coal	62	37	42
Source: PJM State of the Market Report, Volume 2, 2008 pages 144, 148 and 152; 2009 pages 161, 164 and 168 and 2010 pages 177, 181 and 185.			

The PJM MMU estimated that the net revenues for a new combined cycle plant in PSE&G's zone were $6,625 per MW/year lower than the unit's levelized fixed costs in 2010. RPM prices would need to increase by $18 per MW/day to eliminate that difference.[43] RPM prices averaged $181 per MW/day in PSE&G's zone in 2010.[44] The RPM price would need to be $199 to eliminate the net revenue deficiency estimated by the PJM MMU.

Deregulation transferred the capital recovery risk and the opportunity for higher profits to generation owners. According to the generation owners, that transfer provides substantial value to consumers. The transfer provides consumers with insurance against the risk that changing circumstances will cause the net book value of the plant to exceed its market value.

Generation Deregulation Momentum

Retail choice has been implemented in fifteen states and the District of Columbia.[45] In most of those states, the incumbent public utilities sold their generating plants or transferred them to non-regulated affiliates. The following table shows the retail choice states.

[43] $6,625 divided by 365 days.
[44] The prices were $191.32 for the 2009/2010 delivery year and $174.29 for the 2010/2011 delivery year.
[45] The District of Columbia is included in the term "states" in the remainder of this chapter to simplify the text.

Table 13-12 - Retail Choice States in the United States, Percentage of Generation From Utility Owned Plants 2010

Retail Choice States in the United States Percentage of Generation From Utility Owned Plants in 2010			
State	Retail Choice Severely Limited	Rate Caps In 2010	Percent Utility Generation
California	Yes	No	45
Connecticut	No	No	0
Delaware	No	No	0
District of Columbia	No	No	0
Illinois	No	Credits	6
Maine	No	No	0
Maryland	No	No	0
Massachusetts	No	No	2
Michigan	Yes	Regulated	80
New Hampshire	No	No	18
New Jersey	No	No	0
New York	No	No	25
Ohio	No	Yes	65
Pennsylvania	No	Yes	1
Rhode Island	No	No	0
Texas	No	No	23
Source: Energy Information Agency website. Electricity Restructuring Status by State as of September 2010 and Electric Power Monthly, Tables 1.6.B and 5.6.B.			

New Jersey LCAPP Law

The New Jersey Act Establishing a Long-Term Capacity Agreement Pilot Program to Promote Construction of Qualified Electric Generation Facilities was signed into law in January 2011 (the LCAPP Law). The LCAPP essentially guarantees a fixed level of capacity payments for new mid-merit and base load power plants for up to 15 years. The size of the program is capped at 2,000 MW. The purpose of the law is to promote the construction of new power plants for the benefit of New Jersey consumers.[46]

The LCAAP Law requires New Jersey's electric distribution companies (EDCs) to enter into financially settled standard offer capacity agreements (SOCAs) with generation developers. The SOCAs require the generation developers to construct new generating units and to bid and clear the new capacity resource in PJM's RPM.

The SOCAs provide the generation developers with net capacity revenues equal to the Standard Offer Capacity Price (SOCP) stated in the agreement. If the SOCP exceeds the price obtained by the developer in the RPM, the EDC pays the difference to the developer. If the RPM price exceeds the SOCP, the developer pays the difference to the EDC. The developer's net capacity revenues always reflect the SOCP.[47]

[46] Order Initiating Proceeding and Approving Agent, BPU Docket No. EO11010026, February 11, 2011.
[47] Order Initiating Proceeding and Approving Agent, BPU Docket No. EO11010026, February 11, 2011, page 3.

The SOCA payments are allocated between the state's four EDCs based on their forecasted peak demand. The SOCA payments are charged or credited to ratepayers through a non-bypassable distribution rate. The rate applies to all electricity deliveries to retail customers.

Eligible generators were required to submit applications to the BPU by February 22, 2011. The new capacity could be located outside of New Jersey, but the proposals were evaluated based on benefits to New Jersey ratepayers. The Law required the approval of the resulting SOCAs by March 30, 2011. The short implementation schedule was needed to allow the selected capacity resources to participate in the May 2011 RPM base residual auction for the 2014/2015 delivery year.

The March 2011 LCAPP Agent's Report, recommended awarding fifteen year SOCAs for the following new gas-fired combined cycle plants.

Table 13-13 - LCAPP Agent Recommendation Portfolio of Recommended SOCAs

LCAPP Agent Recommendation Portfolio of Recommended SOCAs			
Sponsor	Capacity	Location	Initial Delivery
Hess Newark, LLC	625	Newark, NJ	June 2016
New Jersey Power Development, LLC	660	Old Bridge, NJ	June 2015
CPV Shore, LLC	663	Woodbridge, NJ	June 2015
Total	1948		
Source: BPU LCAPP Agent's Report, March 23, 2011, page 2. Capacity is UCAP.			

The BPU approved the recommended contracts on March 29, 2011.[48]

The FERC adopted most of PJM's recommendations on April 12, 2011.[49] The FERC concluded that new plants should not be allowed to bid below ninety percent of net CONE because "if a resource's true cost of new entry is above the price at which the market clears, such a resource is not needed." [50]

[48] BPU Energy Order in Docket No. EO1101026, dated February 11, 2011.

[49] Order Accepting Tariff Revisions, Subject to Conditions, and Addressing Related Complaint, FERC Docket No. ER11-2875-000, April 12, 2011.

[50] Order Accepting Tariff Revisions, Subject to Conditions, and Addressing Related Complaint, FERC Docket No. ER11-2875-000, April 12, 2011, page 26.

PSE&G Management - Objectives and Overall Strategy

PSE&G spends $3.5 billion a year on purchased power. The power markets are subject to significant uncertainty. Concerns about wholesale market design and high prices have halted the trend towards generation deregulation in the United States. Power supply management should be a priority for PSE&G. PS Power accounted for 75 percent of PSEG's consolidated net income in 2009 and 73 percent in 2010.[51]

PSE&G's overall power supply strategy is to: (1) purchase default supply in BGS auctions; (2) sell the power it buys under NUG contracts into PJM markets; and (3) comply with BPU directives concerning demand response, renewable generation and distributed generation.[52]

PSE&G's supply objectives are to (1) purchase power at prices consistent with competitive market conditions, (2) provide a modest level of price stability; and (3) protect the company against supplier defaults.[53]

In PSE&G's view, the BGS-FP structure has been a success. The BGS passed the stress test provided in recent years by $150 a barrel oil, the financial market crises and economic recession.[54]

Transmission enhancements can reduce energy and capacity prices by reducing transmission constraints. PJM's "Market Efficiency Analysis" is an economic transmission planning process to identify transmission upgrades with economic benefits that exceed their costs.[55]

PSE&G's NUG contracts are discussed in Chapter 15. PSE&G's only demand response program is a 192 MW air-conditioning cycling program for residential and small commercial customers.

The BPU's New Jersey Clean Energy Program has primary responsibility for energy efficiency programs in New Jersey. PSE&G has several energy efficiency programs that are targeted to specific customer groups. Those programs have limited terms and are scheduled to expire in the near future.

PSE&G has two solar generation programs. The first provides for the installation of 80 MW of utility-owned generation. The second provides loans for up to 81 MW customer-owned installations.

PSE&G's demand response, energy efficiency and solar programs were implemented pursuant to BPU directives.[56] Those programs are addressed in Chapter 14.

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[51] PSE&G web-site, PSEG 2010 Earning Release, February 22, 2011, Attachment 3.
[52] Robinson interview, March 3, 2010.
[53] Robinson interview and Joint Proposal of New Jersey's electric utilities for Basic Generation Service, July 1, 2010, BPU Docket No. ER10040287, pages 4 and 5.
[54] Robinson interview and Initial Joint Comments of PSE&G and PSEG ER&T for BPU Capacity Issues Technical Conference, July 2, 2010.
[55] PJM 2009 Regional Transmission Expansion Plan, February 26, 2010, page 9.
[56] Matos interview, October 9, 2010.

Organization and Staffing

The following groups are responsible for PSE&G's power supply planning function:[57]

- Energy Acquisition;
- Transmission Business Strategy;
- Electric Delivery Planning; and
- Renewables and Energy Solutions.

The Energy Acquisition Group (EAG) is responsible for BGS and NUG procurement. The Transmission Business Strategy Group (TBSG) is responsible for PSE&G's participation in PJM and FERC market design matters. The Electric Delivery Planning Group (EDPG) is responsible for transmission system planning. The Renewables and Energy Solutions Group (RESG) is responsible for PSE&G's demand response, energy efficiency and solar generation programs. The RESG is discussed in Chapter 14. Overland interviewed the leaders of each of the four groups.

Energy Acquisition Group

The EAG has primary responsibility for PSE&G's power supply planning function.[58] The group has a headcount of five and includes the following positions:[59]

- Director - BGS/BGSS Services
- Manager - Basic Generation Services
- Manager - Basic Gas Supply Services
- Manager - NUG Contracts
- Project Coordinator

BGSS refers to PSE&G's Basic Gas Supply Service Tariff. BGSS is the default supply for gas distribution customers that do not opt for third party retail suppliers.[60]

The EAG spends most of its time on: (1) BGS and BGSS regulatory proceedings and related reporting requirements; (2) managing PSE&G's BGS and NUG contracts; and (3) managing PSE&G's BGSS contract with PSEG ER&T. The EAG takes the lead in preparing PSE&G's filings in the annual BGS proceedings.[61]

[57] Response to Discovery, OC-194 and Robinson, Napoli, Khadr and Matos interviews.
[58] Robinson interview, March 3, 2010 and Response to Discovery, OC-161.
[59] Response to Discovery, OC-1270.
[60] PSE&G Gas Tariff Sheet 54.
[61] Robinson interview, March 3, 2010.

The Director BGS/BGSS Services is the lead person within PSE&G that is responsible for reviewing PSE&G's power supply strategy on an integrated basis, aside from information then provided to senior management.
During his interview with Overland, the Director - BGS/BGSS Services indicated he was not involved in the New Jersey Energy Master Plan process and did not know who PSE&G's lead person was for that process.[62]

PSE&G prepares "mark-to-market" studies each month. Those studies quantify the difference between contract prices and PJM energy futures prices to determine credit security requirements under the BGS-FP contracts.[63] They are the only market analyses received by the EAG.[64]

The EAG does not prepare cost/benefit studies of alternative power supply strategies. The group does not prepare or review any power supply plans beyond those contained in BGS filings.[65]

The EAG is a regulatory and contract management group, not a power supply planning group. The group does not have the staffing needed to identify and assess least-cost power procurement strategies for default supply customers.

Transmission Business Strategy Group

The TBSG is responsible for:[66]

- Monitoring and influencing PJM market rules and developing related strategies to improve PSE&G's regulatory and business position;
- Transmission rates and tariffs, including PSE&G's annual transmission formula rate filings;
- Transmission interconnection management, including administering PSE&G's joint transmission line agreements and interconnection agreements with merchant generators.
- Regional Reliability Organization interface and reliability standards compliance.

The group has a headcount of eight, organized into the following areas.

[62] Robinson interview, March 3, 2010.
[63] Response to Discovery, OC-685.
[64] Robinson interview, March 3, 2010.
[65] Robinson interview, March 3, 2010.
[66] Response to Discovery, OC-878.

Table 13-14 - Transmission Business Strategy Group, Headcounts as of September 2010

Transmission Business Strategy Group Headcount as of September 2010	
Area	Positions
Director's Office	2
Transmission Rates and Tariffs	2
Interconnection Planning	2
Reliability Policies and Standards	2
Total	8
Source: Response to Discovery, OC-1270	

The TBSG is responsible for PSE&G's participation in PJM committees. The TBSG is responsible for developing PSE&G's strategies concerning PJM market design issues.[67]

PJM market rules are the subject of numerous FERC proceedings. PJM market rules are complex and constantly changing. PJM market rules have a direct impact on BGS-FP prices.

As of September 2009, PJM had 46 committees, sub-committees, working groups, task forces and user groups. PJM holds over 300 stakeholder meetings a year.[68]

As discussed in Chapter 16, PSE&G relies on PS ER&T for expertise on PJM "markets issues" because the TBSG lacks the expertise to independently analyze those issues. That provides ER&T with an opportunity to shape PSE&G's positions to advance merchant generation interests.

The TBSG does not have the staffing resources needed to independently analyze PJM market rules and promote the interests of BGS-FP customers at PJM or FERC.

Electric Delivery Planning Group

The EDPG is responsible for transmission and distribution system planning. The group has a headcount of ten, including the director. Four positions work primarily on distribution planning and five work primarily on transmission planning.[69]

PJM is responsible for transmission planning in its region. The planning can be divided into two areas, reliability and economic expansion planning. Reliability planning is conducted first and focuses on identifying violations of reliability standards and proposing solutions. PJM identifies potential violations and PSE&G recommends proposed solutions subject to PJM approval. Economic planning focuses on

[67] Response to Discovery, OC-878.
[68] An Assessment of PJM's Governance and Stakeholder Process, RAAB Associates, September 17, 2009, pages 22 and 23. Report commissioned by PJM.
[69] Response to Discovery, OC-1341.

identifying transmission enhancements that will lower system energy and capacity costs. PJM takes the lead in economic planning.[70]

PJM's transmission planning models do not include low voltage transmission facilities. PSE&G does the modeling for the transmission facilities that are not included in PJM's models.[71]

The EDPG focuses primarily on planning to achieve system reliability objectives. The group's transmission planning activities include:[72]

- Support for PJM's regional transmission planning process and merchant interconnection planning processes.
- Prepare load flow studies, short-circuit studies and stability analyses and reviews the studies prepared by PJM.
- Review the transmission projects included in PJM's annual regional transmission expansion plan (RTEP).
- Provide support to PSE&G's project construction and systems operations groups; and
- Provide regulatory support in FERC, BPU and municipal siting proceedings.

PSE&G's economic system planning model, PROMOD, is a production cost model that estimates system costs based on specified assumptions, including transmission system configuration. The EDPG prepares PSE&G's PROMOD studies. PJM uses PROMOD for its market efficiency analysis process.[73]

PSE&G does not use PROMOD for economic transmission expansion planning. In the past three years, PSE&G only prepared five PROMOD studies. Four were load flow studies used to estimate the electrical magnetic field impacts of new transmission projects. The other was a CO2 leakage study of the Susquehanna-Roseland line requested by the BPU staff.[74]

PJM estimates energy and capacity (RPM) cost savings resulting from adding new transmission lines in its market efficiency analysis. PSE&G does not replicate the benefits calculated by PJM.[75]

PJM and PSE&G both use the data base of generating facility parameters provided by the PROMOD Vendor. PJM publishes the assumptions used in its market efficiency analyses. As a result, PSE&G has the capability to replicate the results of PJM's market efficiency studies. PSE&G estimates it would take approximately 700 hours to replicate PJM's results.[76]

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[70] Khadr interview, October 9, 2010.
[71] Calore interview, March 3, 2010.
[72] Response to Discovery, OC-1320 and Khadr interview.
[73] PJM website, Transmission Expansion Advisory Committee, May 12, 2010 presentation titled 2010 Market Efficiency Analysis Final Input Assumptions, page 2.
[74] Response to Discovery, OC-1318.
[75] Khadr interview, October 9, 2010.
[76] Response to Discovery, OC-1318.

PJM has approved six backbone transmission projects in the past five years.[77] Two of those projects are at least partially located in PSE&G's transmission zone, the Susquehanna-Roseland 500 kv line initially approved in the 2007 RTEP and the Branchburg-Roseland-Hudson 500 kv line initially approved in the 2008 RTEP. Both projects were approved based on reliability criteria.

In March 2007, PJM estimated that the Susquehanna - Roseland project would reduce the average price of energy in PSE&G's zone by 62 cents per MWH in 2013. The energy savings for load serving entities in PSE&G's zone were estimated to be $33 million in 2013.[78] PSE&G has not prepared any estimates of the energy or capacity savings produced by the line.[79] PSE&G has not prepared any studies of the economic benefits of the Branchburg-Roseland-Hudson line.[80]

PSE&G only has one employee who can run the PROMOD model.[81] PSE&G does not have the staffing to do a lot of PROMOD studies.[82] PSE&G believes its current economic transmission planning staffing is adequate because PJM has not proposed many projects based on economics. PSE&G will reevaluate its staffing needs if the number of projects proposed by PJM increases in the future.[83]

Transmission enhancements and PJM market rules have significant impacts on market participants and PSE&G's power supply costs. PSE&G does not prepare economic planning studies of transmission enhancements or PJM market rules. PSE&G's staffing in those areas is inadequate.

Power Supply Plans

All of PSE&G's power requirements are procured through the BGS process. PSE&G's power supply strategy is documented in its filings in the BPU's BGS proceedings. No other strategy documents or plans exist.[84]

PSE&G does not have any power supply plans.[85] PSE&G does not engage in integrated resource planning.[86]

The EAG prepared a presentation to management concerning the long-term contract proposal that LS Power made in PSE&G's 2009 BGS proceedings. That presentation is the only power supply study prepared by PSE&G in recent years.[87]

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[77] PJM 2009 Regional Transmission Expansion Plan, February 26, 2010, page 5.
[78] Response to Discovery, OC-1326.
[79] Khadr interview, October 9, 2010.
[80] Khadr interview. The Branchburg-Roseland-Hudson line line was replaced by a smaller 230 kv project in 2010.
[81] Response to Discovery, OC-1320.
[82] Khadr interview, October 9, 2010.
[83] Response to Discovery, OC-1320.
[84] Response to Discovery, OC-160, OC-161 and Robinson interview, March 3, 2010.
[85] Response to Discovery, OC-160, OC-161 and Robinson interview, March 3, 2010.
[86] Response to Discovery, OC-161 and OC-292.
[87] Robinson interview, March 3, 2010.

PSE&G prepares load forecasts for distribution and transmission planning purposes.[88] PSE&G prepares three-year forecasts of PJM energy prices based on futures market data to determine credit requirements for BGS suppliers.[89] Beyond three years, PSE&G forecasts PJM energy prices by applying an annual escalation factor of 2 or 3 percent.[90] PSE&G does not prepare any other forecasts or plans related to power supply.

The TBSG does not prepare any written transmission strategies or plans. The Director TBS is not aware of any written PSE&G transmission strategic plans. The only documentation of PSE&G's strategies concerning PJM issues are the filings that PSE&G makes at FERC.[91]

Analysis of Power Supply Alternatives

Overland conducted extensive discovery designed to identify the analyses of market conditions, market structure and strategic alternatives conducted by PSE&G.

PSE&G performed two studies associated with power supply alternatives. The first was a review of the long-term contract proposal made by LS Power in the 2009 BGS proceeding. The second was a technical power flow analysis of a new transmission line prepared to challenge the cost allocation for that line at FERC.

PSE&G recommended several changes to PJM/NYISO (New York Independent System Operator) interface pricing rules in 2010.[92] However, it has not analyzed the potential impact of those recommendations on energy prices in PSE&G's transmission zone.[93]

PSE&G's only strategy for reducing transmission congestion costs is to rely on the PJM regional transmission planning process.[94] PSE&G has not undertaken any independent efforts to reduce congestion costs.

The PSEG transmission zone has the highest operating reserve costs in PJM.[95] PSE&G has no understanding of why operating reserve costs are so high in its zone and has not attempted to study the matter.[96]

Management Direction and Oversight

[88] Robinson interview, March 3, 2010 and Responses to Discovery, OC-879 and OC-273.
[89] Response to Discovery, OC-685.
[90] Response to Discovery, OC-175.
[91] Napoli interview, October 8, 2010 and Response to Discovery, OC-950.
[92] Comments of PSEG Companies, FERC Docket ER08-1281-004, February 2, 2010.
[93] Napoli and Khadr interviews and Response to Discovery, OC-1092 and OC-1093.
[94] Response to Discovery, OC-1129.
[95] PJM 2009 State of the Market Report, Volume 2, page 222.
[96] Response to Discovery, OC-1068 and OC-1069.

PSE&G's president monitors the progress of the BGS proceedings and auction. PSE&G's executive management did not review any other information pertaining to default power supply in 2009 or the first seven months of 2010.[97]

During the 19 month period ending July 2010, PSE&G's executive management did not receive any written reports, analyses or presentations pertaining the following:[98]

- PJM market design issues or power supply alternatives;
- BGS power procurement other than the materials filed by PSE&G and other parties in the annual BPU BGS proceedings.

However, the President of PSE&G is kept informed of the progress of the auction process by his direct reports. In addition, the President of PSE&G is also kept informed of the progress of the auction during the auction itself by the same direct reports.[99]
The PSE&G and PSEG Boards of Directors did not receive any reports or presentations concerning BGS power procurement during the same 19 month period. [100]

The TBSG does not provide written reports to senior management concerning PJM issues.[101] TBSG prepares minimal technical analysis. Strategy development is not prone to technical analysis. PSE&G's strategy is to support competition.[102]

The TBSG does not have a separate balanced scorecard or PIP goals.[103] The TBSG is included in the Electric Delivery balanced scorecard. That scorecard does not include any goals pertaining to power supply.[104]

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[97] Response to Discovery, OC-1102 and OC-1100.
[98] Response to Discovery, OC-1102 and OC-1100.
[99] Response to Discovery, OC-1102.
[100] Response to Discovery, OC-1101.
[101] Napoli interview, October 8, 2010 and Response to Discovery, OC-1206.
[102] Napoli interview, October 8, 2010.
[103] Response to Discovery, OC-517 and Napoli interview, October 8, 2010.
[104] The Electric Delivery area also has strategic initiatives which include goals. The only strategic initiatives that implicate power supply are the Smart Grid and Regional Transmission Expansion initiatives. Those strategic initiatives focus on implementing utility capital projects rather than PJM market design.

14. Demand Response, Energy Efficiency, and Renewable Generation

This Chapter addresses PSE&G's management of demand response (DR), energy efficiency (EE) and renewable generation.

Summary of Findings

The findings contained in this Chapter are listed below.

1. DR programs have the potential to produce substantial benefits for consumers. PSE&G's DR objectives, strategies and plans are guided by the New Jersey Energy Master Plan and BPU policy. PSE&G's BPU filings are the only documentation of its DR strategies and plans.

2. PSE&G's only DR program is an air conditioning cycling program for residential and small commercial customers. The program currently has a capacity value of about 62 MW. PSE&G is expanding the program to 192 MW.

3. PJM has two basic types of DR - capacity and economic. PSE&G does not have any plans or strategies for promoting participation in PJM DR programs.

4. Participation in the PJM capacity program increased significantly in PSE&G's zone in the most recent RPM auction. In PSE&G's zone, DR capacity equaled about ten percent of the peak demand.

5. PSE&G has been highly critical of PJM's capacity program. According to PSE&G, the capacity program provides substantial payments to participants "for doing very little without incurring much risk." PSE&G recommended eliminating the program in 2010. PSE&G also recommends reducing the amount of capacity that can participate and implementing stricter qualification and verification requirements.

6. The capacity program has three different products - Limited DR, Extended Summer DR, and Annual DR. PJM believes the Extended Summer product is a good fit for air conditioning cycling programs. PSE&G currently bids its cycling program as Limited DR. Extended Summer DR can potentially receive higher RPM prices.

7. Participation levels in PJM's DR Economic Program are very low. The FERC recommended increasing the compensation paid to economic program participants in May 2010. PSE&G opposes that recommendation.

8. PSE&G has not analyzed the factors impacting participation in the PJM DR Economic Program. PSE&G has not made any efforts to promote the Economic Program.

9. The New Jersey Office of Clean Energy (OCE) has primary responsibility for implementing EE in New Jersey. The BPU is considering transferring primary responsibility for EE programs to the state's utilities.

10. PSE&G implemented temporary EE programs in 2008 and 2009. The programs include both electric and gas EE and focus on low-income enterprise zones and specific industries. PSE&G's programs are designed to complement the OCE's programs.

11. The PSE&G EE programs have a 2011 budget of $58 million. The programs are scheduled to terminate in 2011 and 2012. PSE&G submitted an application to extend the programs in January 2011. PSE&G requested additional funding of $95 million to be expended over four years.

12. The combined OCE and PSE&G 2011 budget for electric EE in PSE&G's service territory is approximately $158 million, which equals about $73 per customer. Electric EE funding is relatively modest compared to PSE&G's power supply costs.

13. According to PSE&G, aggressive development of cost-effective EE needs to be a key element of New Jersey's Energy Master Plan; and New Jersey residents and businesses are not investing in EE at nearly the rate needed to meet the state's goals.

14. EE programs are a cost-effective way to reduce power supply costs. PSE&G's power supply costs are among the highest in the nation. High power supply costs justify a strong focus on EE. PSE&G should work to fully integrate EE into its power supply planning.

15. EE programs can be bid as capacity resources in the RPM if they comply with PJM measurement and verification rules. PSE&G's existing programs do not meet those requirements. PSE&G has not assessed the costs and benefits of qualifying future EE programs for the RPM.

16. PSE&G supports renewable energy development. Solar generation is the most viable renewable energy development opportunity in PSE&G's service territory. PSE&G has two programs for promoting solar generation, the Solar Load program and the Solar-4-All (S4A) program.

17. The Solar Loan program provides loans for the installation of small-sized customer-owned photovoltaic solar units. The program has a total capacity of 81 MW. PSE&G's investment will be $240 million once the installations are completed. The loans cover approximately fifty percent of the installed cost. In addition to the loans, participants are eligible for federal tax credits.

18. The S4A budget is $515 million. The program consists of two utility-owned 40 MW segments - centralized solar installations, and utility pole-top installations. The utility pole-top segment consists of 200,000 solar systems installed on utility and street light poles. The pole-top installation is the largest in the world.

19. PSE&G sells the power produced by the S4A installations in PJM energy and capacity markets. PSE&G did not bid all the available capacity in RPM auctions in 2010. The installed capacity was 28 MW as of December 2010. PSE&G only bid 18 MW in the September 2010 auction for the delivery year that starts in June 2012.[1]

20. PSE&G currently sells the pole-top solar output in PJM energy and capacity markets.

Recommendations

1. PSE&G should prepare an assessment of the growth potential of the PJM DR Economic Program and develop strategies for promoting optimum participation levels.

2. PSE&G should consider bidding future energy efficiency programs into the RPM capacity auction.

3. PSE&G should publish the results of its solar programs.

4. PSE&G should commit all 40 MW of centralized solar capacity in the RPM auctions held in May, July and September 2011.

5. PSE&G should consider treating the pole top solar output as a reduction of the BGS-FP load pool.

6. PSE&G should describe its plans for committing that incremental capacity for the 2012/2013 RPM delivery year in its response to this audit.

Organization and Staffing

PSE&G has the following programs to promote demand response, energy efficiency and solar generation. [2]

- Demand Response: Air conditioning cycling programs for residential and small commercial customers.

[1] PSE&G bids partial capacity for projects which are substantially constructed, but have not been completed. Partial capacity is bid for projects under construction to account for potential changes to final system sizes, which may occur prior to project completion.

[2] Response to Discovery, OC-122 and Matos interview.

- Energy Efficiency: Energy Efficiency Economic Stimulus and Carbon Abatement Programs. Also Comfort Partners program.
- Solar Generation: Solar 4 All and Solar Loan Programs.

The programs are managed by the Renewables and Energy Solutions Group (RESG). The RESG includes a headcount of 13 positions.[3]

The group's activities include:[4]

- Managing the implementation of the residential and small commercial air conditioning cycling program;
- Managing the Solar Loan program, including processing customer applications for loans;
- Business and implementation planning for the energy efficiency and solar programs; and
- Development of BPU regulatory filings.

Demand Response

Benefits and Goals

DR programs pay customers to reduce consumption during periods when load is high. DR reduces total system energy and capacity costs in two basic ways.

- Reducing peak demand delays the need to build expensive new generating stations; and
- Reducing energy consumption shifts the energy pricing point to a lower price on the supply curve.

Under PJM's single energy clearing price regime, energy prices reflect the generator bid accepted to serve the last increment of load. During peak hours, the energy supply curve tends to be very steep. As a result, relatively small reductions in load can result in large price reductions.

DR programs have the potential to produce substantial benefits for consumers. The Brattle Group prepared a study of the energy price impact of demand response during peak days in the Mid-Atlantic region of PJM. The study covered the top twenty 5-hour price blocks in 2005 for the PSEG, PECO, BGE, Delmarva and Pepco zones. Brattle concluded that reducing load by three percent during those hours reduced energy prices in the Mid-Atlantic region by five to eight percent.

The study assumed that all five zones curtailed load in their individual top twenty 5-hour blocks. The market impact would be much smaller if only one zone curtailed load in isolation.[5]

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[3] Response to Discovery, OC-1270, page 39.

[4] Matos interview, October 9, 2010.

[5] Quantifying Demand Response Benefits in PJM, Brattle Group, January 29, 2007, Prepared for PJM and the Mid-Atlantic Distributed Resources Initiative, MADRI.

PSE&G's demand response objective is to comply with the New Jersey Energy Master plan (NJEMP). PSE&G's strategies and plans are guided by directives from the BPU.[6]

The NJEMP is in the process of being updated. According to PSE&G's VP-RSEG, the PJM markets are doing a good job providing demand response resources. The appropriate role for PSE&G is an open question. The BPU's demand response policies are in flux while the EMP is being revised. PSE&G needs guidance from the BPU regarding its role.[7]

PSE&G does not have any plans or strategies for promoting participation in the PJM demand response programs other than implementing air conditioning cycling programs for residential and small commercial customers.[8] PSE&G's BPU filings are the only documentation of its demand response plans and strategies.

PSE&G conducted market research on incentives for its air conditioning cycling program in 2010.[9] That was the only demand response study prepared by PSE&G in the past three years. PSE&G does not monitor the efforts made by other utilities to promote demand response participation. [10]

PJM Programs

PJM has two basic types of demand response programs - capacity and energy. The energy program was created in 2002 and is named the Economic Load Response Program (Economic Program).

PJM's DR capacity market has three different products.

- Limited DR;
- Extended Summer DR; and
- Annual DR.

The Limited DR product was created in 2002. The Extended Summer and Annual products were approved by FERC in January 2011.[11] The Limited DR product was previously named the Emergency Load Response Program. The name was changed in 2011 to differentiate it from the new Extended Summer and Annual products.

The purpose of the capacity products is to maintain system reliability by curtailing load during capacity shortages. The three capacity programs have different curtailment requirements as shown below.

[6] Matos interview, October 9, 2010.
[7] Matos interview, October 9, 2010.
[8] Matos interview, October 9, 2010, Response to Discovery, OC-1336 and OC-1067.
[9] Response to Discovery, OC-1330, PSE&G RGGI Recovery Charges Petition, October 1, 2010, Schedule FAL-DR-1, PSE&G AC Cycling Incentive Research, Inforgroup/ORC, report dated May 2010.
[10] Matos interview, October 9, 2010.
[11] Order on Proposed Tariff Provisions, FERC Docket ER11-2288-000, January 31, 2011.

Table 14-1 - PJM Demand Response Capacity Products

PJM Demand Response Capacity Products Curtailment Requirements			
Product	**Months**	**Number**	**Duration**
Annual	All	Unlimited	10 hours
Extended Summer	May - October	Unlimited	10 hours
Limited	June - September	10 per year	Six hours
Source: PJM OATT Tariff Filing, FERC Docket ER11-2288-000, December 2, 2010.			

The capacity products are bid into the RPM (reliability pricing model) capacity auction. Annual DR has a higher reliability value than Extended Summer DR because Annual DR is available throughout the year. Extended Summer DR has a higher reliability value than Limited DR. The three capacity products can clear at different prices in the RPM auctions when reliability needs justify a higher price for the products with stricter curtailment requirements.

The purpose of the Economic Program is to reduce energy prices when prices are high. Participants receive a payment from PJM for voluntarily curtailing load. High energy prices increase the incentive to curtail load.

Curtailment Services Providers

End-use customers participate in PJM DR programs through curtailment services providers (CSPs). CSPs are PJM members who act as agents for the customers. Prior to 2009, PSE&G did not know the identity of the CSPs operating in its zone.[12] In December 2008, the BPU approved an incentive program to encourage demand response participation. The program paid CSPs $22.50 per MW for new and incremental Emergency Program capacity in 2009. The program was not renewed for 2010.

PSE&G made $1.1 million in incentive payments to 22 CSPs in February 2010 under that program.[13] That required PSE&G to determine the names and addresses of the CSPs. PSE&G does not know how many CSPs are currently active in its zone.[14]

PSE&G's Utility Finance Group reviews the applications CSPs submit to PJM to determine if the nominated capacity is plausible. PSE&G's Business Services Group reviews PJM's demand response energy settlements for reasonableness.[15]

[12] Matos interview, October 9, 2010.
[13] Response to Discovery, OC-1067.
[14] Matos interview, October 9, 2010.
[15] Matos interview, October 9, 2010. There are very few energy settlements to review because curtailments are very rare in PSE&G's zone.

PSE&G does not monitor CSP satisfaction levels.[16] PSE&G did not receive any complaints from CSPs in 2009 or 2010.[17] PSE&G did not dispute any demand response settlements in 2009 or 2010.[18]

PJM Capacity Program

The Limited DR program curtails load during load management emergency events declared by PJM. PJM rarely declares load management emergency events. The events are declared by zone. In the past four years, only two emergency events were declared for PSE&G's zone; a three-hour event on August 8, 2007 and a four-hour event on August 11, 2010.[19] It is also noted that PJM called one emergency event in 2011 on May 31, 2011 and PSE&G instituted an event for economic conditions on July 21 and 22.[20]

Limited DR resources bid their curtailment obligations into PJM's RPM capacity market as a supply resource. That reduces RPM prices by shifting the intersection of the demand and supply curves to a lower price. Participants also receive an energy payment from PJM during curtailment periods. Because curtailments are very rare, RPM capacity revenues account for virtually all of the payments that PJM makes to Limited DR resources.

Emergency event load response is not a new concept. Electric utilities offered interruptible load tariffs to large industrial customers when generation costs were included in bundled retail electricity rates. The difference is that large customers are now paid for their curtailment obligation through the RPM instead of through discounts on bundled retail rates.

PJM had 7,294 MW of registered Limited DR resources as of August 2009. Of that total, 313 MW was located within the PSE&G transmission zone.[21]

Participation in the PJM capacity program increased significantly in the PSE&G zone in the most recent RPM auction. The following table shows the Limited DR resources that cleared in the two most recent RPM base residual auctions.

[16] Matos interview, October 9, 2010.
[17] Response to Discovery, OC-1334.
[18] Response to Discovery, OC-1335.
[19] PJM Load Management Performance Report, 2010/2011, pages 12, 13 and 19.
[20] Response to discovery request, email from Mally Becker, 11/18/11.
[21] PJM 2009 State of the Market Report, Volume II, page 121. Includes legacy Interruptible Load for Reliability Program.

Table 14-2 - Limited DR Resources

Limited DR Resources Cleared MW In Base Residual Auction		
Delivery Year Ending May	PJM Total	PSEG Zone
2013	7,047	460
2014	9,282	1,119
Source: PJM website, RPM 2012/2013 and 2013/2014 Base Residual Auction Results Reports.		

The 2013/2014 preliminary zonal peak load forecast for PSE&G's transmission zone is 11,188 MW.[22] The cleared Limited DR resources (unforced capacity) represent 10 percent of peak load.

The following table shows the Limited DR resources that cleared for the 2013/2014 delivery year for all PJM zones.

[22] PJM web-site, RPM Users Information, 2013/2014 Delivery Year Base Residual Auction Parameters Report.

Table 14-3 - PJM Limited DR Resources MW Capacity Cleared

PJM Limited DR Resources MW Capacity Cleared in 2013/2014 RPM Base Residual Auction			
Zone	Peak Demand	Demand Response	Percentage
Atlantic Electric	3,019	122	4
American Electric Power (Note 1)	2,227	824	36.2
Allegheny Power	8,859	523	5.9
ATSI (Note 2)	13,364	394	2.9
Baltimore Gas & Electric	7,621	1,103	14.5
Commonwealth Edison	24,138	852	3.5
Dayton P&L	3,521	43	1.2
Delmarva P&L	4,059	246	6.1
Dominion	21,138	633	3
Duquesne	2,922	142	4.9
Jersey Central P&L	6,733	284	4.2
Metropolitan Edison	3,064	318	10.4
Peco Energy	8,830	658	7.5
Pennsylvania Electric	2,929	421	14.4
Pepco	7,094	547	7.7
PPL Electric	7,627	1,021	13.4
PSEG	11,188	1,119	10
Rockland Electric	444	32	7.2
Total	138,827	9,282	6.7

Note 1: AEP reduced for FRR obligations
Note 2: ATSI includes Ohio Edison, Toledo Edison, Cleveland Electric and Pennsylvania Power (utilities owned by First Energy)
Source: PJM 2013/2014 RPM Base Residual Auction Results Report

PSE&G has not analyzed the reasons for the increased participation in its zone.[23] According to PSE&G's VP-RESG, participation increased because of higher RPM capacity prices. The increase was the not the result of actions taken by PSE&G.[24]

The increase is the result of increased participation by large industrial customers who are served by TPR suppliers. CSPs are aggressively promoting the Limited DR product to those customers. The VP-RESG is not aware of any particular customers or CSPs who have produced the increase.[25]

The RPM price in PSE&G's zone is $245 per MW/Day for the delivery year ending May 2014. The Limited DR resources in PSE&G's zone will receive $106 million in that delivery year.[26]

[23] Response to Discovery, OC-1067.
[24] Matos interview, October 9, 2010.
[25] Matos interview, October 9, 2010. In many instances the TPR suppliers are also CSPs..
[26] 1,189 MW x $245 x 365 = $106.3 million.

PSE&G has been highly critical of the PJM capacity program. PSE&G recommended requiring all DR resources to participate in the Economic Program in Comments filed at FERC in May 2010.[27]

According to PSE&G, the RPM capacity markets provide DR resources with substantial payments "for doing very little without incurring very much risk."[28] PSE&G indicated the participation of DR resources in the RPM acted as an impediment to participation in the Economic Program.

Participants in the Economic Program must have infrastructure in place to reduce load and the skills needed to bid into the energy markets. Economic Program participants only get paid when they curtail load. Industrial customers that suspend operations incur direct costs and opportunity costs. They also incur risks, because if they commit to a curtailment and fail to perform, they must purchase replacement power in the spot market.

The "easy money" paid to DR capacity resources in the RPM discourages participation in the Economic Program. Participants do not have sufficient incentive to participate in the Economic Program when they are allowed to bid as capacity resources in RPM auctions.[29]

New PJM DR Capacity Products

PJM's Annual DR and Extended Summer DR products were implemented in 2011 to address reliability concerns about the Limited DR product. PJM published a demand response saturation analysis in May 2010.[30] The report evaluated the reliability value of PJM's existing DR capacity product (the Limited DR product). The PJM analysis focused on the limitations on the frequency and duration of curtailments. The analysis concluded:

- DR should be capped at 8.5 percent of forecasted unrestricted peak demand on an RTO (regional transmission organization)-wide basis;
- DR in PJM's Eastern Mid-Atlantic Area (Reliability) Council Region (EMAAC) should be capped at 14 percent of unrestricted peak demand; and
- The curtailment duration should be expanded from six to ten hours.

The expansion of the curtailment duration was intended "to ensure that the daily peak is reduced by the full amount of the implemented DR."[31] PJM subsequently decided not to expand the duration for the existing capacity product. Instead, it lowered the quantity cap to accomplish the same objective. PJM recommended capping the quantity of Limited DR resources purchased for the 2013/2014 RPM delivery year to 4.7 percent of peak demand.[32]

[27] Comments of PSEG Companies, FERC Docket No. RM10-17-000, May 13, 2010, pages 12 and 16 .
[28] Comments of PSEG Companies, FERC Docket No. RM10-17-000, May 13, 2010, page 12.
[29] Comments of PSEG Companies, FERC Docket No. RM10-17-000, May 13, 2010, page 12.
[30] Demand Resource Saturation Analysis, PJM Resource Adequacy Planning Department, May 2010.
[31] Demand Resource Saturation Analysis, PJM Resource Adequacy Planning Department, May 2010, page 11.
[32] PJM Tariff Filing, FERC Docket ER11-2288-000, December 2, 2010, page 16.

PJM proposed the new Annual and Extended Summer DR products in December 2010. The new products were approved by FERC in late January 2011. The Annual and Extended Summer products allow more frequent curtailments for longer durations during more months of the year. The "less-limited" response capabilities of those products address the reliability concerns associated with the Limited DR product.[33]

PJM proposed the Extended Summer product as an intermediate product to encourage broader participation. According to PJM the Extended Summer product is a good fit for existing utility air conditioning cycling programs. PJM's experience with those programs indicates they should be physically capable of interrupting more frequently and for longer durations than required by the existing Limited DR product.[34]

PSE&G argued that the caps proposed by PJM on the quantities of Limited DR and Extended DR that could be purchased through the RPM were too high. NERC requires PJM to meet a Loss of Load Expectation (LOLE) reliability standard of one day in ten years.[35] According to PSE&G, the methodology for calculating the caps proposed by PJM results in violations of that standard.[36]

While PJM indicated Limited DR should be capped at 4.7 percent of peak demand, PSE&G recommended lowering that cap to about 3 percent. PJM indicated Extended Summer DR should be capped at 10.6 percent of peak demand. PSE&G recommended lowering that cap to about 6.5 percent.[37]

PSE&G also wants stricter qualification and verification requirements for DR resources. According to PSE&G, PJM's procedures allow DR resources to bid in RPM auctions without meeting any meaningful advance certification standards. PJM needs a mechanism for pre-auction certification of realistic levels of DR resources.[38]

PSE&G also proposed that DR bidders should be required to demonstrate the existence of contracts for new DR facilities prior to the auction. Annual DR resources should be required to submit documentation of their ability to perform in non-summer periods and should be required to test in non-summer periods. Annual DR resources should be required to demonstrate their capability to respond to an unlimited number of curtailment requests.[39]

PSE&G opposed the implementation of the Annual and Extended DR products for the 2013/2014 RPM delivery year. According to PSE&G, relying on the new DR products created an unacceptable reliability risk because customers might leave the DR programs if curtailments become more frequent. PJM's reliance on the new less-limited products to meet reliability standards lacks support because "PJM fails to identify

[33] Order on Proposed Tariff Revisions, FERC Docket ER11-2288-000, January 31, 2011.

[34] PJM Tariff Filing, FERC Docket ER11-2288-000, December 2, 2010, page 24.

[35] NERC is the North American Electric Reliability Corporation. NERC is the Electric Reliability Organization certified by FERC to establish and enforce electric reliability standards.

[36] Motion to Intervene and Protest of PSEG Companies, FERC Docket ER11-2288-000, December 23, 2010, page 22.

[37] Motion to Intervene and Protest of PSEG Companies, FERC Docket ER11-2288-000, December 23, 2010, page 23.

[38] Motion to Intervene and Protest of PSEG Companies, FERC Docket ER11-2288-000, December 23, 2010, pages 5 and 14.

[39] Motion to Intervene and Protest of PSEG Companies, FERC Docket ER11-2288-000, December 23, 2010, page 29.

- and the PSE&G Companies are not otherwise aware of - studies or surveys that provide an assessment of how frequently consumer(s) are willing to curtail service."[40]

PSE&G recommended: (1) further study of the Annual DR product; and (2) capping Limited DR capacity at about 3 percent of peak load.

According to PSE&G, the long-term solution is to eliminate the Extended Summer and Limited DR products and require all DR resources to bid as Annual DR products. Treating limited DR products as full capacity resources has a detrimental effect on reliability and discriminates against generation.[41] The PJM Independent Market Monitor also recommends requiring all DR resources to bid as Annual Resources. [42]

According to PSE&G, all DR resources should be required to submit bids in PJM's energy markets. Generation resources that clear in the RPM are required to bid into the day-ahead energy market. The current practice of not requiring DR resources to bid in the energy markets is discriminatory against generation.

Requiring DR resources to perform only in emergencies is inconsistent with PJM's long-term vision of developing price responsive demand. Consumers do not realize energy price suppression benefits when DR resources are not activated.[43]

Under PSE&G's proposal, DR resources with limited response capabilities would be able to participate as part of a portfolio of DR resources which, in combination, qualifies as an Annual DR product. This would allow the continued participation of air conditioning cycling programs. PSE&G recommends the implementation of a PJM DR "aggregation auction" to match up and combine limited resources into Annual DR products.[44]

PSE&G's Air Conditioning Cycling Program

PSE&G's Cool Customer program has existed for many years. The program reduces residential air conditioning load during PJM load management emergency events. The program relies primarily on cycling switches attached to the customers air conditioner compressor. The switches allow PSE&G to directly control the customer's air conditioner. The Cool Customer program had approximately 125,000 participants in 2009, providing approximately 62 MW of demand response capacity.[45]

PSE&G is currently expanding it's a/c cycling program. The BPU's July 1, 2008 Demand Response Order directed New Jersey's electric utilities to submit proposals for demand response programs that could be

[40] Motion to Intervene and Protest of PSEG Companies, FERC Docket ER11-2288-000, December 23, 2010, page 29.
[41] Motion to Intervene and Protest of PSEG Companies, FERC Docket ER11-2288-000, December 23, 2010, page 29.
[42] Protest of the Independent Market Monitor for PJM, FERC Docket ER11-2288-000, December 20, 2010, page 2.
[43] Motion to Intervene and Protest of PSEG Companies, FERC Docket ER11-2288-000, December 23, 2010, page 30.
[44] Motion to Intervene and Protest of PSEG Companies, FERC Docket ER11-2288-000, December 23, 2010, page 30.
[45] Response to Discovery, OC-855. The program also included some heat pumps and programable thermostats. The direct load control switches accounted for the vast majority of the participants and demand response capacity. The programable thermostats allow PSE&G's to directly control air conditioning cycling.

implemented by July 1, 2009. The BPU established a state wide goal of 600 MW of additional demand response by May 2012. PSE&G's share of that goal was 330 MW.[46]

PSE&G submitted its proposal in August 2008. PSE&G's proposal included the following capacity targets for March 2014.

Table 14-4 - PSEG 2008 Demand Response Proposal 2014 Capacity Targets

PSEG 2008 Demand Response Proposal Submitted To the BPU in August 2008 2014 Capacity Targets	
Program	**MW**
Residential AC Cycling	131
Residential Pool Pump	2
Small Commercial AC Cycling	19
Commercial and Industrial Curtailment Services Provider	240
Total	393
Source: PSEG Petition in BPU Docket No. EO08050326, dated August 5, 2008, pages 6 to 8.	

The residential air conditioning cycling program is a replacement for the Cool Customer program (the legacy program). The 2014 capacity target shown above includes approximately 62 MW transferred from the legacy program. The total incremental demand response capacity proposed by PSE&G was approximately 331 MW.[47]

The BPU approved the new cycling programs in July 2009. The BPU has not acted on the other programs proposed by PSE&G.[48]

PSE&G proposed acting as a CSP for commercial and industrial customers in its 2008 filing. Participation in PJM's Emergency Program has expanded significantly since 2008. PSEG no longer sees a need to act as a CSP.[49]

The residential cycling program is much larger than the program for small commercial customers. The residential program will replace the legacy program equipment with new equipment and add new participants. The budget for the residential program is $60 million. PSE&G awarded the purchase order for the new equipment in May 2010.[50]

[46] PSE&G Petition in BPU Docket No. EO08050326, dated August 5, 2008
[47] 2014 total of 393 MW less 62 MW transferred from legacy program.
[48] Response to Discovery, OC-1067 and OC-1330 (PSEG RGGI Recovery Charges Petition, October 1, 2010)
[49] Matos interview, October 9, 2010
[50] Response to Discovery, OC-1330, PSE&G RGGI Recovery Charges Petition, October 1, 2010, Direct Testimony of Frederick A. Lynk, page 4.

The unit cost of the new equipment for the residential program was lower than the amount planned in 2008. PSE&G proposes to use the equipment savings to expand the program. The original participation target was 168,300 residential customers. PSE&G is proposing to raise that target to 225,371 customers.[51] The legacy program had approximately 125,000 participants.[52] The revised target represents an addition of 100,000 new participants.

PSE&G estimates demand response capacity of 0.72 Kw for each residential participant.[53] The 100,000 new participants will increase demand response capacity by approximately 72 MW.

Curtailments are expected to be rare under both air conditioning cycling programs. Load is curtailed if either of the following conditions exist: (1) a PJM declared load management emergency event; or (2) the combination of a weighted average temperature humidity index of at least 80 and a day-ahead average LMP (locational marginal pricing) for the PSEG zone of at least $250. Load was not curtailed in 2009 and was only curtailed once in 2010. PSE&G only expects one curtailment in 2011.[54]

The temperature and LMP criteria were added at the request of the BPU staff. They provide a economic price response component to the program. The $250 LMP threshold has not been triggered in recent years.[55] The cycling programs are primarily capacity programs with a weak link to energy market price reduction objectives.

Under the residential program, customers can choose between a direct load control switch or a programable thermostat. For customers who select a switch, the program incentives are bill credits of $16 a year plus $1 per curtailment. For customers that select the programable thermostat, the incentive is a free thermostat and a one time payment of $50.[56] Most customers have opted for the direct load control switch. They prefer the ongoing bill credits to the one-time incentives for the thermostat.[57]

The original residential target of 168,300 customers represented 17 percent of PSE&G's residential customers who have central air conditioning. The revised target represents approximately 23 percent of eligible customers. It may be difficult to meet that target. Residential customers may drop out of the program if curtailments become more frequent.[58]

[51] Response to Discovery, OC-1330, PSE&G RGGI Recovery Charges Petition, October 1, 2010, Direct Testimony of Frederick A. Lynk, page 4.

[52] Response to Discovery, OC-855

[53] Response to Discovery, OC-1330, PSE&G RGGI Recovery Charges Petition, October 1, 2010, Direct Testimony of Frederick A. Lynk, page 2.

[54] PSE&G web-site, Cool Customer Program page, and Response to Discovery, OC-1330, Direct Testimony of Frederick A. Lynk, pages 6 and 7.

[55] Matos interview, October 9, 2010

[56] Response to Discovery, OC-1330, PSE&G RGGI Recovery Charges Petition, October 1, 2010, Direct Testimony of Frederick A. Lynk, pages 2 and 3.

[57] Matos interview, October 9, 2010

[58] Matos interview, October 9, 2010

PSE&G focused on transferring legacy program participants to the revised residential program in 2009 and 2010. PSE&G added approximately 5,697 new participants to the program in 2010, and expects to add another 37,464 new participants in 2011.[59]

The budget for the small commercial cycling program is $5.1 million. PSE&G estimates demand response capacity of 1.66 Kw per participant.[60] The small commercial program incentives are bill credits of $30 per year and a programable thermostat. The value of the thermostat is approximately $250. [61]

PSE&G has not had much success marketing the program to small commercial customers. PSE&G is revising its marketing plan for the small commercial program. The incentives may need to be increased to meet program targets.[62]

PSE&G bid the following capacity amounts into the RPM for the cycling programs.

Table 14-5 - PSEG Air Conditioning Cycling Program Capacity Bid into RPM

PSEG Air Conditioning Cycling Program Capacity Bid into RPM	
Delivery Year Ending	**MW**
May 2013	64
May 2014	125
Source: Response to Discovery, OC-1327	

The 64 MW bid for the 2012/2013 delivery year is approximately equal to the legacy program capacity. PSE&G expects to add a total of 43,161 new participants to the residential program by the end of 2011. That equates to approximately 31 MW of new capacity.[63] PSE&G should describe its plans for committing that incremental capacity for the 2012/2013 RPM delivery year in its response to this audit.

In its 2008 filing, PSE&G estimated the cycling program would provide 125 MW of capacity by March 2013.[64] The bid for the 2013/2014 delivery year is consistent with that forecast.

PSE&G's 2008 forecast includes another 27 MW to be installed by March 2014. PSE&G proposed expanding the residential program by approximately 40 MW in its October 2010 filing. PSE&G should

[59] Response to Discovery, OC-1330, PSE&G RGGI Recovery Charges Petition, October 1, 2010, Direct Testimony of Frederick A. Lynk, page 4.

[60] Response to Discovery, OC-1330, PSE&G RGGI Recovery Charges Petition, October 1, 2010, Direct Testimony of Frederick A. Lynk, pages 3 and 4

[61] Response to Discovery, OC-1331

[62] Matos interview, October 9, 2010 and Response to Discovery, OC-1330, PSE&G RGGI Recovery Charges Petition, October 1, 2010, Direct Testimony of Frederick A. Lynk, pages 7 and 8.

[63] 43,151 x 0.72 kw per participant equals 31,076 Kw or 31 MW.

[64] PSE&G Petition, BPU Docket EO08050326, dated August 5, 2008, pages 6 and 7.

adopt a goal of committing the full 192 MW of program capacity in the base residual auction for the 2014/2015 delivery year held in May 2011.

Recommendation: PSE&G should consider qualifying its air conditioning cycling program as an Extended Summer DR resource.

PJM believes the Extended Summer DR product is a good fit for air conditioner cycling programs. Extended Summer DR products can potentially receive higher RPM capacity prices than Limited DR products. The extent of the future price separation is currently unknown.

The price separation may justify modifying PSE&G's air conditioning cycling program to qualify as an Extended Summer DR product. The program capacity is 192 MW. If the prices separate by $20 per MW/day, qualifying the entire program as an Extended Summer resource would increase annual capacity revenue by $1.4 million.[65]

The Extended Summer DR product does not include any limits on the frequency of curtailments. PJM's criteria for dispatching Extended Summer DR products are unclear. The FERC requested additional information on PJM's dispatch criteria in its Order approving the new products.[66]

According to PSE&G, air conditioning cycling programs may not be a good fit for the Extended Summer DR product because customers may leave the program if curtailments become more frequent.

The rules for PSE&G's cycling programs indicate PSE&G can initiate up to 20 curtailments per year for electric reliability support and economic energy management using the following criteria.[67]

- Regional Emergencies - when regional demand for electricity is close to surpassing regional supply;
- Local Emergencies - when local demand for electricity is close to overloading the local distribution system; or
- Non-Emergency - during high temperature/humidity conditions causing abnormally high energy prices.

The rules indicate:

> *PSE&G will make every effort to limit cycling events to weekdays generally between the hours of 1:00 pm and 7:00 pm, but such events could occur on any day at any time and for longer durations as may be required under certain circumstances in the event of system emergencies.*

[65] 192 MW times $20 times 365 days equals $1,401,600.

[66] Order on Proposed Tariff Provisions, FERC Docket ER11-2288-000, January 31, 2011, page 18. FERC required PJM to include an explanation of its dispatch methods for the three capacity products in its 30 day compliance filing due 30 days after the date of the order.

[67] PJM web-site, Cool Customer Program page, Terms and Conditions.

The program rules may inhibit PSE&G's ability to qualify all of the program capacity as Extended Summer DR.

PSE&G should prepare a study of the advantages and disadvantages of bidding its air conditioning cycling program as an Extended Summer product in RPM auctions. The study should:

- Estimate the expected price differential between Limited DR and Extended DR products in PSE&G's transmission zone;
- Estimate the expected number of curtailments for the Limited DR and Extended Summer DR products;
- Assess the impact of expected curtailment frequencies on program participation levels;
- Estimate the amount of Limited DR and Extended DR capacity that PSE&G will offer in RPM auctions under current program terms;
- Identify and assess the modifications of program terms needed to increase the amount of capacity offered as an Extended Summer DR resource, and
- Recommend the program terms and bidding strategies that will optimize the capacity revenues received by the program and overall consumer benefits.

PJM Economic Program

Participation in the Economic Program is measured using two metrics - registrations and curtailments. Participants must register for the program. Registration provides the participant with the option of voluntarily bidding into the energy market. As of January 10, 2011, Economic Program registrations totaled 2,441 MW in PJM with 56 MW in PSE&G's zone.[68]

Economic Program energy curtailments are concentrated in a few zones as shown in the following table.

[68] PJM Load Response Activity Report, January to December 2010, pages 2 and 3.

Table 14-6 - PJM Economic Load Response Program Energy Curtailment by Zone

PJM Economic Load Response Program Energy Curtailments by Zone - MWH 2009 and 2010		
Zone	**2009**	**2010**
PPL Electric Utilities	21220	479
PECO Energy	15265	31696
Dominion	5989	27160
American Electric Power	5214	7
Baltimore Gas & Electric	58	3679
Allegheny Power	2150	4377
Commonwealth Edison	960	2287
PSE&G	309	61
Other zones	516	511
Total	51681	70257
Source: PJM 2009 State of the Market Report page 117 and PJM Load Response Activity Report, January-December 2010.		

The curtailments represent only a small fraction of the 760 million MWH of energy used by end-use customers in the PJM region in 2009.[69] The curtailments in PSEG's zone totaled 309 MWH in 2009 and 61 MWH in 2010. PSE&G delivered 42 million MWH to distribution customers in 2009. . . .

Economic Program participation levels are very low. PSE&G has not analyzed the factors impacting participation rates.[70] PSE&G has not made any effort to promote participation in the program.[71]

According to Citigroup, Economic Program curtailments are an extremely expensive "source" of energy. Price responsive demand is expensive because:[72]

> *Folks that offer to curtail their power supply have to compare what else [they] could do with that power. Could I be running my manufacturing plant? Could I be generating profits from my plant? Or is it better for me to shut off my power and sell that into the energy market?*
>
> *So I would encourage you to think about demand response in effect like a super peaker: Cheap to install but very expensive to draw down in the energy market.*

According to PSE&G's VP-RSEG, the incentives to participate in the program are not sufficient to attract participants when energy prices are low. Industrial customers are not willing to curtail for an incentive

[69] PJM Load Forecast Report, January 2010, page 65.
[70] Response to Discovery, OC-1066
[71] Response to Discovery, OC-1336 and OC-1066
[72] BPU New Jersey Capacity Issues Technical Conference, June 24, 2010, transcript page 79 and Citigroup presentation, page 7.

payment of $100 per MWH. The incentive would have to be much higher than that to significantly increase participation in the Economic Program.[73]

Participation in the Economic Program requires an investment in load control equipment. Large industrial customers and their CSPs are not interested in investing in energy management equipment at current energy price levels.[74]

PSE&G has not analyzed the potential for Economic Program growth in its zone, The VP-RSEG does not expect significant growth in the Economic Program over the next few years. CSPs are not promoting the program.[75]

PJM pays the participants a price per MWH equal to the spot market energy price less the generation (G) and transmission (T) components of the customer's retail rate. That shorthand for that formula is LMP - G - T. PJM proposed changing the pricing formula to LMP - G in 2010.[76]

When the customer curtails energy consumption, they avoid the generation portion of their retail rate. According to PJM, paying participants LMP - G provides the participant with the same incentives to curtail usage that they would have if they directly purchased all of their energy requirements in the hourly spot market. The incentive comes in two parts - a reduction in their retail energy bill and a payment from PJM.

PSE&G's BGS-CIEP (Commercial and Industrial Energy Pricing) customers pay retail generation rates that vary on hourly basis to fully incorporate the LMP for PSE&G's zone.[77] As a result, their LMP - G - T is less than zero and they do not receive any payment from PJM for participating in the PJM Economic Program. Their only incentive to curtail is avoiding paying for energy under PSE&G's CIEP tariff.

The generation portion of the retail rates paid by customers of TPR suppliers are not regulated by the BPU. The incentives that TPR suppliers and their customers have to participate in the Economic Program are apparently not significant, given the low participation levels.

The FERC proposed paying participants in the Economic Program the full LMP, without offsets, in a Notice of Proposed Rulemaking issued in March 2010.[78] The BPU supports the FERC's proposal.[79] The FERC concluded that paying full LMP compensates Economic Program participants based on the marginal value

[73] Matos interview, October 9, 2010.
[74] Matos interview, October 9, 2010
[75] Matos interview, October 9, 2010
[76] PJM concluded that deducting T was improper because transmission costs were fixed costs that were not avoided by curtailing load.
[77] PSE&G Electric Tariff Sheet No. 82.
[78] Notice of Proposed Rulemaking, FERC Docket No. RM10-17-000, March 18, 2010.
[79] Comments of the New Jersey BPU, FERC Docket No. RM10-17-000, May 13, 2010.

they provide. LMP reflects the marginal cost of the last generating unit necessary to meet demand. By curtailing load, consumers avoid purchasing the last increment of power.

The incremental costs saved by a one MWH curtailment is clearly the LMP. Therefore, LMP should be paid to any resource clearing in the energy market, including load curtailments. According to FERC, a one megawatt reduction in demand is equivalent to a one megawatt increase in generation for purposes of meeting load requirements.[80]

PSE&G opposes increasing the compensation paid to Economic Program participants. According to PSE&G, paying full LMP over-compensates participants. PSE&G recommends paying LMP - G.[81] If PJM pays full LMP, and the participant also avoids paying the generation portion of its retail rate, the total benefit received by the participant exceeds LMP. According to PSE&G that will distort the market.

PSE&G has not analyzed the impact that paying full LMP would have on Economic Program participation.[82] Economic Program participants can face significant direct costs and opportunity costs when they curtail. PSE&G's narrow focus on reductions in the participant's retail electricity bill ignores those other costs.

FERC's proposal focuses on using competitive bidding to select the resources procured to balance supply and demand. All generating units that are dispatched to serve load receive the same price in the energy market regardless of their individual cost structures. Under the FERC's approach, the cost structures of the individual Economic Program participants do not affect the price they receive from PJM.

Recommendation: PSE&G should analyze the growth potential of the PJM's Economic Program.

The RPM provides ample incentive for participation in PJM's DR capacity programs. Limited DR participation levels are high in PSE&G's zone. In contrast, participation in the Economic Program is minimal.

PSE&G has not taken any actions to promote participation in the Economic Program. The Economic Program has the potential to reduce energy prices during periods of high demand. The FERC is currently considering a significant increase in Economic Program participation incentives. That has significant power supply planning implications.

PSE&G has not analyzed the potential for future growth in the Economic Program. The major uncertain factor is the willingness of industrial customers to curtail load at various LMP pricing points. PSE&G should reach out to PJM for its views on the factors impacting growth in the Economic Program. PSE&G should survey the CSPs and large energy users in its zone to identify and assess:

80 Notice of Proposed Rulemaking, FERC Docket No. RM10-17-000, March 18, 2010.
81 Comments of the PSEG Companies, FERC Docket No. RM10-17-000, May 13, 2010.
82 Matos interview, October 9, 2010.

- The willingness of different customer types to curtail at various LMP pricing points;
- Factors impacting program participation levels;
- The potential for increased participation; and
- Strategies for increasing participation.

The current low participation levels imply that price responsive curtailments are a very expensive energy source. PSE&G needs to determine if the Economic Program is a viable strategy for managing power supply costs.

PSE&G has not reviewed the efforts made by other utilities to promote participation in demand response. PSE&G should conduct a best practices review of the efforts of other PJM utilities to promote participation in the Economic Program.

According to PSE&G's VP-RSEG, CSPs are not interested in financing the energy management equipment needed to participate in the Economic Program. PSE&G should consider on-bill utility financing of that equipment.

PSE&G should develop strategies for promoting optimal participation levels in the PJM Economic Program, upon completion of the best practices review and assessment of program potential.

Energy Efficiency

New Jersey Clean Energy Program

The New Jersey Office of Clean Energy (OCE) has primary responsibility for implementing energy efficiency (EE) programs in the state. The OCE's EE programs are included in its Clean Energy Program (CEP). The CEP also includes renewable generation programs.

The CEP was authorized by the New Jersey Electric Discount and Energy Competition Act (EDECA) passed in 1999. The CEP began in 2001, and is funded by the Societal Benefits Charge. The CEP is a signature initiative of the BPU. The BPU sets the policies, goals and budget for the OCE and the CEP.[83] Stakeholder input is provided through monthly CEP Energy Efficiency Committee meetings.

The 2011 CE EE budget is $294 million.[84] The budget includes both electric and natural gas EE programs. Electric EE programs account for 60 percent of the budget.[85] PSE&G accounts for 55 percent of the peak

[83] New Jersey Clean Energy Program, 2008 Annual Report, page 7

[84] BPU Clean Energy Order, Docket Nos. EO07030203 and EO10110865, dated December 22, 2010, page 51. The 2011 budget includes $77 million of expenditures committed but not spent in 2010.

[85] BPU Clean Energy Order establishing 2009-2012 Funding Levels, Docket No. EPO07030203, September 30, 2008, page 23.

electrical demand in New Jersey. A rough estimate of the amount of the 2011 CEP electric EE budget allocable to PSE&G is $100 million.[86]

The CEP EE programs are managed by the following contractors.

- Program Coordinator - Applied Energy Group
- Residential - Honeywell International, Inc
- Commercial and Industrial Programs - TRC Energy Services

The Comfort Partners Program for low income customers has been managed by the state's utilities on behalf of the OCE since 2001 and is implemented by contractors who are overseen by the state's utilities. The CEP's programs include energy audits, rebates, and the direct installation of energy savings measures. Program incentives include rebates for the purchase of energy efficiency appliances and grants and financing for the cost of EE measures.

The following table shows the 2011 EE budget by customer type.

Table 14-7 - NJ Clean Energy Program Energy Efficiency Budget by Customer Type

New Jersey Clean Energy Program Energy Efficiency Budget by Customer Type 2011 - Dollars in Millions		
Type	**Budget**	**Percent**
Residential	113	38
Commercial and Industrial	151	51
Future Program Not Assigned	30	10
Total	294	100
Source: BPU Clean Energy Order, December 22, 2010, page 51.		

Many of CEP's residential programs provide rebates for purchasing energy efficient appliances. The following table shows 2009 residential participants by program.

[86] $294 million x 60% x 55% equals $97 million, round to $100 million.

Table 14-8 - 2008 CEP EE Residential Program Participants by Type

2008 CEP EE Residential Program Participants By Type	
Type	**Number**
High Efficiency Heating and Cooling Equipment Rebates	21,282
New Homes built and certified to Energy Star Standards	3,236
Room Air Conditioner Rebates	7,528
Clothes Washer Rebates	25,424
Dehumidifier Rebates	8,017
Free On-Line Energy Audit Participants	5,836
Comfort Partners Low Income Program	7,779
Other Homeowner Incentive Programs	3,310
Total	82,412
Source: Clean Energy Program web-site, Financial Reports tab, 2001-2009 Program Results and 2008 CEP Annual Report, page 14.	

In addition, CEP provided incentives to lighting manufactures, distributors and retailers to offer discounted compact fluorescent bulbs and high efficiency lighting fixtures in New Jersey stores. The CEP's commercial and industrial programs had 1,963 participants in 2009.

The OCE estimates the electric programs implemented from 2001 through December 2009 reduced state peak demand by 470 MW.[87] The cost of obtaining that reduction was roughly $1,000 per Kw.[88] That is roughly comparable to the construction cost of a new combustion turbine. However, while EE fuel costs are assumed to be zero, individual EE measures can decrease one form of energy usage while causing an increase in usage of another fuel.

OCE estimates lifetime savings of 26.6 million MWH for the electric expenditures made through December 2009. Based on that, each MWH saved over the life of the installation costs roughly $18.[89] However, since OCE does not track electric and gas costs separately, there could be significant variation in this estimate. The power procured through the 2010 BGS auction cost $96 per MWH.

PSE&G's VP-RESG indicated the company has a good working relationship with the OCE and the CEP programs are working. The VP-RESG indicated: [90]

[87] Clean Energy Program web-site, financial reports tab, 2001 - 2008 program results.
[88] Total program expenditures of $790 million x 60 percent electric indicated electric expenditures of $474 million.
[89] $474 million estimated electric EE program costs divided by 26.6 million MWH lifetime savings. The expenditures occur in the year of installation while the savings occur over the life of the installation. Overland has not estimated the net present value of the savings.
[90] Matos interview, October 9, 2010

- State contracting rules make it difficult to modify programs in a timely manner.
- As a result of increases in equipment standards, CEP air conditioner efficiency rebates may have diminishing returns.
- Tightening up New Jersey's construction codes could reduce the need for some programs targeted at new construction.
- Cost effectiveness of appliance rebates should be evaluated properly.
- Reliance on utility on-bill financing of EE measures should be increased.

PSE&G Energy Efficiency Programs

PSE&G implemented temporary EE programs in 2008 and 2009. PSE&G filed its Carbon Abatement (CA) program petition in June 2008. The CA included five small-scale, limited term, EE programs for residential and small commercial customers. The BPU approved modified CA programs in December 2008. The CA program budget was $51million to be spent over four years.

PSE&G filed its Energy Efficiency Economic Stimulus (E3) program petition in January 2009 in response to the Governors request that utilities invest $500 million in EE to spur the state's economy. The BPU approved modified E3 programs in July 2009. The E3 program budget was $190 million to be committed by December 31, 2010. Projects committed during that 18-month period will continue to be installed and completed through early 2013.

The CA and E3 authorized funding includes both electric and natural gas programs. The CA and E3 programs focus on low-income urban enterprise zones and specific industries.[91] The CA and E3 programs are designed to complement CEP program. The low income and specific industry "carve out" avoids duplication of CEP programs.[92]

The CA and E3 programs are managed as a single EE portfolio. Three of the E3 programs are expansions of existing CA programs. The 2011 electric EE budgets are shown below.

[91] There are 25 urban enterprise zones in PSE&G's service territory.
[92] Matos interview, October 9, 2010

Table 14-9 - PSEG CA and E3 Electric EE Programs, 2011 Budget

PSEG CA and E3 Electric EE Programs 2011 Budget- Dollars in Thousands	
Title	Budget
Residential Whole House	3,688
Residential Programmable Thermostat	197
Residential Multi-Family Housing	11,189
Small Business Direct Install	9,634
Municipal Direct Install	7,407
Large Business Demonstration Pilot (Warehouse Lighting)	297
Hospitals	16,331
Data Centers	8,239
Building O&M (Large Grocery Supermarkets)	1,245
Technology Demonstration Grants	299
Total	58,426
Response to Discovery, OC-1330 pages 130 and 138. (October 1, 2010 RGGI Recovery Charge Filing)	

The programs include energy audits, direct installation of measures, incentives, and on-bill repayment of the customers' share of the cost of energy efficiency measures. Many of the programs provide for PSE&G to finance the customer's share of the installation costs with repayment charges included on the customer's monthly utility bill over several years. That type of financing is referred to as "on-bill" financing.

E3 funding accounts for 92 percent of the 2011 budget. The E3 programs were scheduled to close to new applicants at the end of 2010. PSE&G requested an extension of the programs through 2011 without additional funding.[93] The CA programs will close to new participants by the end of 2012. The Multi-Family, Municipal, Hospital, Data Center and Supermarket programs were fully subscribed by mid-2010 and had waiting lists of applicants that could not be funded at that time.[94]

PSE&G proposed an E3 Extension Program in January 2011 to extend the multi-family, municipal and hospital programs. In July 2011 the BPU approved a PSE&G E3 budget of $103 million to be expended in 2011 through 2014.[95]

The state of New Jersey is currently updating the EMP. PSE&G will assess how it can assist the state in meeting its goals after that process is completed.[96]

[93] NJCEP Transition White Paper for Stakeholder Discussion, BPU Staff, November 4, 2010.
[94] Response to Discovery, OC-1330, Direct Testimony of Robin Elaine Bryant.
[95] PSEG 2010 SEC 10-K Report, page 29 and PSEG Presentation to the Financial Community, March 7, 2011, page 34. The program was submitted to the BPU on January 24, 2011.
[96] Matos interview, October 9, 2010.

Potential Reorganization

The BPU Staff and stakeholders discussed transitioning the CEP to a new management structure throughout 2010. On November 4, 2010, the BPU Staff issued a NJCEP Transition White Paper For Stakeholder Discussion (the Staff white paper). The Staff white paper was developed with input from the OCE, CEP contractors and New Jersey's electric and natural gas distribution utilities.

The Staff white paper indicated the BPU was considering transferring overall management of the CEP to one of the following four alternatives.

- Electric and gas distribution utilities;
- A state agency;
- Trade organizations; or
- A newly created state energy efficiency utility.[97]

The Staff white paper listed the following objectives.

- Economic development and job creation.
- Supporting revised EMP goals.
- Transitioning from rebate-based incentive programs to programs that are more market-based, including public and/or private financing programs.
- Reducing administrative costs of the CEP and utility managed EE programs.
- Consistent programs across the state.
- Ratepayer benefits for all customer classes.

Programs that provide rebates directly to consumers can have high transaction costs. While providing incentives directly to suppliers was identified as possibly more cost-effective, there was no supporting cost-benefit analysis of this assumption. Utility "on-bill" financing of EE installations is also a more cost-effective approach for some cash and/or credit constrained sectors and for some programs. The Staff proposed transitioning away from consumer rebates to reduce administrative costs related to multiple small transactions. The white paper also suggests shifting funding to programs that target large energy consumers.

The Staff white paper recommends consideration of a competitive bidding approach. Under that approach, various entities would bid against each other to provide EE benefits at the lowest price.

[97] Energy efficiency utilities have been created in several states with mixed results. Northeast Energy Efficiency Partnerships, Inc. (NEEP) recommended an energy efficiency utility in its March 2009 report titled "An Energy Efficiency Strategy for New Jersey" prepared for the BPU.

The New Jersey Utilities Association (NJUA) submitted comments on the Staff white paper on December 3, 2010. PSE&G joined in those comments. The NJUA recommended transferring the CEP EE programs back to the utilities for the following reasons.

- The OCE is subject to state government contracting rules and disbursement policies. The rules and policies create stumbling blocks and delays for contractors and customers that could be avoided with utility management of the EE programs.
- Prior to 2007, the utilities managed most EE programs. The utilities currently manage the E3 programs. The utilities enjoy a good relationship with the existing EE contractor base.
- Utilities have superior knowledge of their service territories and more frequent contact with customers.
- Utilities can use account information to target customers eligible for specific programs.
- Utilities have superior flexibility in implementing and modifying programs. The utilities have demonstrated the capability to implement programs in a timely manner.

The NJUA comments support shifting more funding to industrial and large commercial EE programs and focusing on specific market sectors, but caution against entirely abandoning the residential and small commercial markets.

The NJUA comments indicate that "utility funded on-bill financing is proving to be extremely popular with customers because it avoids the normal financing hassles, provides funding in small amounts where commercial lending is not viable, does not result in another bill and generally results in a lower utility bill."

The NJUA comments indicate "the creation and establishment of an [Energy Efficiency Utility] would be significantly more complex and time consuming than the white paper assumes, with very little to be gained over the joint operation of the EE programs by the utilities."

The utilities managed many of the CEP EE programs prior to 2007. When the decision was made to transfer those programs from the utility to the state, it took more than three years to complete that transition.[98] The NJUA comments conclude that "it is more prudent to resume utility EE program management...than to transition to a third administrative model in less than ten years."

[98] NJUA comments on the 2011 CEP Budget, November 17, 2010, BPU Docket No. EO07030203.

Funding Levels

Combined Clean Energy Program (CEP) and PSE&G Electric EE funding is relatively modest compared to PSE&G's power supply costs. The combined 2011 CEP and PSE&G budget for electric EE in PSE&G's service territory is approximately $158 million.[99] In 2009, PSE&G spent $3.0 billion on BGS-FP power purchases. The combined CEP and PSE&G 2011 EE budget equals roughly 5 percent of PSE&G's BGS-FP power supply costs.

The combined EE budgets should be compared to the total power supply costs of all of the electricity consumers in PSE&G's service territory, including those served by TPR suppliers and those served under the BGS-CIEP tariff. In 2009, PSE&G delivered 41.8 million MWH to end use customers.[100] Based on 2009 deliveries, the 2011 EE budget equals $3.8 per MWH . As of December 31, 2009, PSE&G had 2.16 million electric distribution customers.[101] The combined CEP and PSE&G 2011 electric EE budget equals approximately $73 per customer.

Only a small fraction of New Jersey's electricity consumers participate in the CEP EE programs. During 2009, only 84,375 customers participated in the CEP EE programs. Of the total participants, 55% were related to rebates from two programs, HVAC and clothes washer rebates. New Jersey has approximately 3.9 million electricity consumers.[102]

As of July 2009, 24,451 customers had participated in PSE&G's CA and E3 programs (includes both electric and gas). The programmable thermostat program accounted for 51 percent of those participants.

According to PSE&G's VP-RESG, the current level of spending on EE programs is sufficient and there is no need for an increase in the overall budget.[103] However, that opinion is inconsistent with the comments PSE&G recently submitted to the BPU concerning the EMP update. Those comments indicate:[104]

- Achieving much higher levels of energy efficiency must be a fundamental goal of the EMP;
- Aggressive deployment of cost-effective energy efficiency needs to be a key element of the EMP;
- The savings associated with energy efficiency improvements exceed the costs;
- New Jersey residents and businesses are not investing in efficiency at nearly the rate necessary to meet EMP goals; and
- The EMP should include policies to promote further utility involvement in EMP.

[99] $58 million for CA and E3 programs plus an estimated CEP 2011 electric allocation of $100 million.
[100] Response to Discovery, OC-682
[101] Response to Discovery, OC-682
[102] US Energy Information Agency, 2009 Electric Power Annual, Table 7.1
[103] Matos interview, October 9, 2010
[104] Comments of PSE&G, PSEG Power, PSEG ER&T On Energy Master Plan, September 30, 2010

Energy efficiency measures are a cost-effective way to reduce power supply costs. PSE&G's power supply costs are among the highest in the nation. High power supply costs justify a strong focus on EE. PSE&G should work to fully integrate EE into its power supply planning process.

RPM Capacity Revenue

The FERC authorized EE resources to participate as a capacity resource in the RPM in March 2009. The FERC concluded "to the extent possible, energy efficiency solutions should be able to compete on an equal footing with demand response, generation and transmission solutions" and "energy efficiency is a critical part of efficient energy markets, and should be treated comparably to other types of resources, by being allowed to participate in base residual auctions and be paid the auction price when they are accepted..."[105] Energy Efficiency Resources (EE Resources) were allowed to participate in the RPM market, starting with the May 2009 Base Residual Auction. Existing or Planned EE Resources may be offered in an RPM auction starting with the 2011/2012 Delivery Year.

PJM defines EE resources as:[106]

> *...[A] project that involves the installation of more efficient devices/equipment, or the implementation of more efficient processes/systems exceeding the then-current building codes, appliance standards, or other relevant standards, at the time of installation...*

To be eligible to participate in the RPM the EE resource must:[107]

- Be completed prior to the beginning of the delivery year;
- Achieve a permanent, continuous reduction in electric energy consumption between the hours of 2 pm and 5 pm during June, July and August of the delivery year, without any requirement of notice, dispatch or operating intervention;
- Not be reflected in the load forecast used for the Base Residual Auction for the applicable delivery year; and
- Submit a measurement and verification plan to PJM at least 30 days prior to the applicable auction date.

Delivery year peak load forecasts are based on actual peak loads during the summer before the auction. For example, the peak load forecast for the 2012/2013 delivery year used in the May 2009 auction reflected actual peak loads experienced during the summer of 2008.

[105] Order in FERC Docket ER05-1410-000, March 26, 2009, paragraph 131.
[106] PJM Manual 18B: Energy Efficiency Measurement & Verification, page 5
[107] PJM Manual 18, PJM Capacity Market Operations, page 35.

There is a four-year lag between the installation of an EE resource and the recognition of that resource in the delivery year peak demand forecast used in the RPM auctions.[108] An EE project can only participate in the RPM base residual and incremental auctions for those four delivery years.

A project installed in November 2010 will first be reflected in the 2015/2016 delivery year peak demand forecast used in the May 2012 RPM base residual auction. That project is eligible to participate in RPM for the four-year period beginning on June 1, 2011 and ending May 31, 2015.[109]

EE resource providers can group EE resources installed during an energy year into a single resource.[110] For example multiple lighting efficiency projects installed during June 2011 through May 2012 can be grouped together as a single resource.[111]

The following table shows the EE that cleared in the May 2009 and May 2010 Base Residual Auctions.

[108] Order in FERC Docket No. ER05-1410-000, March 26, 2009, paragraphs 120 and 123
[109] PJM Manual 18B, Energy Efficiency Measurement & Verification, page 8
[110] The PJM energy year begins on June 1 and ends on the following May 31.
[111] PJM Energy Manual 18B, Energy Efficiency Measurement and Verification, page 8.

Table 14-10 - PJM Energy Efficiency Capacity Cleared in May 2009 and 2010 Base Residual Auctions

PJM Energy Efficiency Capacity Cleared in May 2009 and May 2010 RPM Base Residual Auctions MW		
Zone	**2012/2013 DY**	**2013/2014 DY**
Atlantic Electric	1	3
American Electric Power	0	4
Allegheny Power	0	2
ATSI (Note 1)	NA	3
Baltimore Gas & Electric	103	75
Commonwealth Edison	387	512
Dayton P&L	0	1
Delmarva P&L	12	3
Dominion	2	5
Duquesne	0	1
Jersey Central P&L	2	4
Metropolitan Edison	0	7
Peco Energy	2	6
Pennsylvania Electric	0	8
Pepco	57	36
PPL Electric	0	2
PSEG	3	7
Rockland Electric	0	0
Total	569	679
Note 1: ATSI includes Ohio Edison, Toledo Edison, Cleveland Electric and Pennsylvania Power (utilities owned by First Energy) Source: PJM 2012/2013 and 2013/2014 RPM Base Residual Auction Results Reports		

Recommendation: PSE&G should consider bidding future energy efficiency programs into the RPM capacity auction.

PSE&G does not bid any of the CA or E3 programs into RPM.[112] PSE&G's VP-RESG does not know if the OCE has any plans to bid CEP EE programs into the RPM.[113]

EE resources must comply with PJM measurement and verification requirements to participate in the RMP auctions. PSE&G's CA and E3 programs do not comply with those requirements, and are not eligible to participate in the RPM. The CA and E3 programs are no longer open to new participants and it is not feasible to retrofit existing installations to comply with PJM requirements.[114]

PSE&G has not assessed the costs and benefits of designing future programs to comply with RPM requirements. According to PSE&G, bidding future EE programs into the RPM would have to be evaluated within the context of PSE&G's overall EE program. Program designs would have to be developed to meet

[112] Response to Discovery, OC-1328.
[113] Matos interivew.
[114] Response to Discovery, OC-1445.

the PJM requirements. Business rules would have to be developed to provide for ongoing measurement and verification. The costs of measurement and verification would have to be budgeted by PSE&G and approved by the BPU.[115]

PSE&G does not monitor the approach used by utilities that bid EE into RPM auctions. PSE&G does not know why the EE capacities bid in the Commonwealth Edison, Baltimore Gas & Electric and Pepco zones are significantly higher than the EE bid in PSE&G's zone.[116]

The most recent RPM auction set a price of $245 per MW day for the PSEG zone. That equals $89 per Kw year or $356 per kw over four years. RPM payments of $356 per kw would offset a substantial portion of the cost of most EE measures.

RPM capacity costs are charged to LSEs (Load Serving Entities). Increased EE participation in the RPM could cause modest reductions in RPM prices. Bidding EE into the RPM would benefit consumers in two ways: (1) offsetting EE implementation costs (or paying for expanded EE programs); and (2) producing modest reductions in the RPM capacity costs incurred by LSEs.

Responsibility for CEP EE programs may be transferred PSE&G in 2012. PSE&G should monitor the methods used by utilities that bid EE programs into the RPM and develop a participation strategy that maximizes the value of EE to electricity consumers in its zone.

PSE&G should investigate the feasibility, costs and benefits of bidding future EE programs into the RPM. If PJM rules unnecessarily discourage participation, PSE&G should develop and implement regulatory strategies for changing the rules to promote full participation.

Renewable Generation

Benefits and Goals

Renewable generation includes hydropower, wind, solar, biomass and geothermal generation. Biomass includes landfill gas and municipal solid waste.[117]

Including renewable generation in a supply portfolio provides the following benefits.

- Improved public health and reduced damage to the environment;
- Reduced exposure to price increases caused by changes in environmental regulations;
- Reduced exposure to fossil fuel price increases.

[115] Response to Discovery, OC-1445.
[116] Response to Discovery, OC-1329 and Matos interview, October 9, 2010.
[117] Renewable generation is a term used for environmentally benign generation from energy sources that can be replenished.

Solar generation tends to be available on hot summer days when energy prices are high and the energy price supply curve is steep.[118] Solar generation can also be distributed throughout the distribution system. Distributed generation reduces line losses and delays the need to increase transmission capacity. Solar and wind equipment manufacturing and installation create jobs, and are viewed as economic development vehicles.

Landfill gas and municipal waste generation are mature industries. New Jersey electric utilities have several legacy NUG contracts with biomass generators.

Photovoltaic (PV) solar and off-shore wind are viewed as the most viable renewable energy development opportunities in New Jersey. PV solar projects tend to be small projects that can be installed relatively quickly. Off-Shore wind projects are large and require many years of development.

Solar and wind are intermittent resources whose output is dependent on the weather and time of day. Intermittent resources do not provide the same degree of reliability as traditional generation and require additional investment to achieve reliability objectives. PJM discounts solar and wind capacity in its RPM auctions to account for their intermittent nature. Solar units are reduced to 38 percent of their capacity and wind units are reduced to 13 percent of their capacity in the RPM.[119]

PV solar and off-shore wind energy unit costs are much higher than the costs of energy efficiency measures. PV solar and Off-Shore wind are also more expensive than traditional generation sources, as shown on the following table.

[118] Adding solar capacity has an energy price suppression benefit. The Solar Alliance estimates that adding 5,000 MW of solar capacity would reduce peak period LMPs by $50 per MWH. Comments of the Solar Alliance, Energy Master Plan Stakeholder Meeting, September 24, 2010.

[119] PJM 2013/2014 RPM Base Residual Auction Results Report, page 9

Table 14-11 - Total System Levelized Costs, Plants Entering Service in 2016

Total System Levelized Costs Plants Entering Service in 2016 (2008 Dollars per MWH)		
Type	Capacity Factor	Cost per MWH
Advanced Coal	85	109
Advanced Gas Combined Cycle	87	63
Advanced Gas Combustion Turbine	30	103
On-Shore Wind	34	97
Off-Shore Wind	34	243
Solar - Photovoltaic	25	211
Solar - Thermal	18	312
Biomass	83	112
Source: Energy Information Agency, Levelized Cost of New Generation Resources in the Annual Energy Outlook 2011. Costs are 2009 Dollars for 2016 in-service date.		

PV solar costs are declining. The levelized cost for PV Solar was estimated at $396 per MWH in EIA's Energy Outlook 2010. One February 2009 study estimated PV solar costs in the range of $131 to $182 per MWH.[120]

The April 2010 Virginia Offshore Wind Studies Final Report estimated levelized costs of $105 to $130 per MWH for a 600 MW off-shore wind farm in shallow water just beyond the horizon.[121]

Coal and nuclear base load units face high barriers to entry. Gas-fired combined cycle units face significantly lower barriers-to-entry than coal and nuclear and have significantly lower unit costs than solar and off-shore wind generation. Solar and off-shore wind provide an opportunity to diversify New Jersey's electricity fuel mix.

PSE&G's VP-RESG expects continued growth in solar generation. People are excited about solar across PJM. Southern New Jersey is the prime location for off-shore wind development in the state. According to PSE&G's VP-RESG, there are no economically viable off-shore wind sites directly adjacent to PSE&G's service territory.[122]

PSE&G supports renewable energy development. PSE&G's September 2010 Comments on the EMP indicate renewable generation development should be a central tenet of the EMP. Solar and off-shore

[120] Lazard, Levelized Cost of Energy Analysis, Version 3.0, February 2009. The cost reflects federal tax credits but does not reflect the value of state renewable energy certificates.
[121] Virginia Offshore Wind Studies, July 2007 to March 2010, Final Report, Virginia Costal Energy Research Consortium, April 20, 2010, page vii. Levelized cost of energy in 2008 Dollars.
[122] Matos interview, October 9, 2010.

wind have tremendous environmental benefits, but are substantially more expensive than traditional generation.

According to PSE&G, utility involvement is needed to successfully promote renewable generation development. Electric distribution utilities can promote renewable generation in ways that reduce unit costs. PSE&G's Solar Loan and Solar-4-All programs should be used as a blueprint for future programs.[123]

PSE&G's comments indicate off-shore wind is New Jersey's most abundant renewable resource and must be fully utilized to meet the state's renewable energy goals. New Jersey must act quickly to head off midwest interests who want to build transmission to export wind generation to the east coast. Those "wind-by-wire" transmission projects would diminish opportunities to develop off-shore wind in New Jersey.

PSE&G is opposed to wind-by-wire transmission projects. New Jersey's best defense against wind-by-wire is to promote off-shore wind. If eastern states can meet RPS requirements from local sources, the justification for wind-by-wire will be eliminated.[124]

New Jersey Renewable Portfolio Standards

New Jersey's Renewable Portfolio Standards (RPS) provide significant incentives for solar and off-shore wind development. The 1999 EDECA required the BPU to implement a RPS. The first RPS was implemented in 2001 and included generation targets for two types of renewable generation.[125]

- Class I: solar, wind, landfill gas, tidal or wave action, fuel cells, geothermal and anaerobic digestion.
- Class II: municipal solid waste and small hydropower projects.

Under the RPS, the BPU issues one renewable energy certificate (REC) to renewable generation owners for each MWH generated. The RPS requires the state's LSEs to obtain RECs sufficient to meet their share of the state's RPS targets each year.[126] This requires the LSEs to purchase RECs from renewable generation owners. The REC sales proceeds provide an incentive for renewable generation development.

The LSEs pass the costs of acquiring the RECs on to New Jersey electricity consumers. New Jersey electricity consumers are the ultimate source of the subsidies for renewable generation provided by the RPS.

[123] Comments of PSE&G, PSEG Power and PSEG ER&T on Energy Master Plan, September 30, 2010, page 7.
[124] Comments of PSE&G, PSEG Power and PSEG ER&T on Energy Master Plan, September 30, 2010, page 9.
[125] New Jersey's Renewable Portfolio Standard Rules, 2009 Annual Report, Draft for Public Comment.
[126] LSE's are required to submit RECs to the BPU to satisfy their RPS obligation or to make Alternative Compliance Payments (ACPs). The ACP price is administratively determined by the BPU. The ACP acts as a cap on the market price of RECs. The ACP price is typically set at a level higher than the levelized cost of generating renewable energy.

Class I and Class II RECs can be purchased from qualified renewable energy sources located anywhere within PJM. As a result, there is an ample supply and prices are relatively low. During the 2009 Energy year, the average price of a Class I REC was approximately \$12 and the average price of a Class II REC was approximately \$1.[127]

The BPU modified the RPS in 2004 to include a carve out from the Class I requirements for New Jersey solar generation. The solar requirements can only be satisfied with Solar Renewable Energy Certificates (SRECs). The SREC sourcing area is limited to New Jersey. As a result, prices are high. As of November 2010, the average price of an SREC was \$616. [128]

The Solar, Class I and Class II requirements were expressed as a percentage of total state electricity consumption. The percentages for Solar and Class I increase every year. The percentage requirements for Class II are frozen at 2.5% in all years. The following table shows the requirements in existence prior to 2010 in five year intervals.

Table 14-12 - NJ Renewable Portfolio Standards Prior to 2010 Legislation

New Jersey Renewable Portfolio Standards Prior to 2010 Legislation Percentage of Electricity Consumption Five Year Intervals				
Year	Solar	Class I	Class II	Total
2006	0.02	0.98	2.5	3.5
2011	0.3	5.5	2.5	8.3
2016	0.93	9.65	2.5	13.08
2021	2.12	17.88	2.5	22.5
Source: New Jersey's Renewable Portfolio Standard Rules, 2009 Annual Report, Draft for Public Comment, Appendix 1.				

The Solar Advancement and Fair Competition Act of 2010 replaced the Class I solar carve out with a fixed schedule of MWH targets. Before the Solar Advancement Act, the solar requirement for 2021 was 2.12 percent. The new fixed MWH target for 2021 equates to 2.76 percent of total electricity consumption. The fixed MWH schedule extends through 2026. The solar target for that year equals approximately 5.3 percent of total electricity consumption. [129]

It is not yet clear how the new solar requirements impact the pre-existing Class I requirements.[130] If the new solar requirements are viewed as an increased carve out from Class I, the 2021 total renewable

[127] New Jersey's Renewable Portfolio Standard Rules, 2009 Annual Report, Draft for Public Comment, pages 18 and 20

[128] Clean Energy Program web-site, Renewable Energy, Project Activity Reports, SREC pricing page.

[129] Preliminary Data Update of the 2008 New Jersey Energy Master Plan, August 13, 2010, page 24. Class II requirement of 2,518 MWH divided by 2.5% equals total consumption of 100,720 GWH. Solar of 5,316 divided by 100,720 is 5.3 percent.

[130] Database of State Incentives for Renewables & Efficiency, dsireusa.org, New Jersey, Renewable Portfolio Standard.

generation target remains at 22.5 percent. If the new solar requirements are an addition to the pre-existing non-solar requirements, the 2021 total renewable generation target is approximately 23.1 percent.

The 2010 Off-Shore Wind Economic Development Act required the nation's first RPS carve out for off-shore wind. The off-shore wind requirements are a carve out from the existing Class I requirements. The Act requires LSE's to obtain Off-Shore Wind Renewable Energy Certificates (ORECs) from New Jersey sources. The Act requires the BPU to establish RPS requirements that will support at least 1,100 MW of off-shore wind over an unspecified time period. The Off-Shore Wind Act also provides tax credits and other financial incentives for generation developers and associated equipment manufacturers.[131]

The following table shows the renewable capacity installed in New Jersey under CEP programs as of November 2010.

Table 14-13 - NJ Renewable Energy Capacity Installed 2001 to November 30, 2010

New Jersey Renewable Energy Capacity Installed 2001 to November 30, 2010 MW	
Type	**MW**
Solar	235
Biomass	31
Fuel Cell	1
Wind	8
Total	275
Source: Clean Energy Program web-site, Renewable Energy, Project Activity Reports.	

The CEP has an additional 215 MW of solar capacity in the application and construction phases. The total amount of solar capacity installed or under development is 450 MW.

The Solar Advancement Act requires LSE's to purchase 5,316 GWH from New Jersey solar generation in 2026. That equates to approximately 3,000 MW of solar generating capacity.[132] The 2026 solar target requires the installation of an average of approximately 170 MW of solar capacity a year for the next 15 years.[133]

[131] Assembly Budget Committee Statement To Assembly Bill, No. 2873, June 24, 2010

[132] At a 20 percent capacity factor, each MW of solar capacity produces 1,752 MWH a year. 5,316,000 MWH divided by 1,752 is 3,034 MW of capacity.

[133] Estimate Assumes 2011 installations equal the existing pipeline of 215 MW. 3,000 minus 450 divided by 15 years is 172.

The solar target for 2017 is 1,357 GWH. That equates to approximately 775 MW of capacity. Meeting that target will require the installation of approximately 54 MW of solar capacity per year for the next 6 years.

The CEP issued 130,161 SERC's for the energy year ended May 31, 2010.[134] The solar RPS requirement during that period were approximately 180,000 MWH.[135]. The shortage of SRECs has produced high prices. Some view SREC prices as being unrealistically high, resulting in an SREC program that is too expensive for consumers.[136]

LSEs are unwilling to enter into long-term contracts with solar developers for the purchase of SRECs. This impedes the development of solar generation and increases SREC prices. BGS-FP suppliers are unwilling to enter into long-term SREC contracts because their BGS-FP supply contracts are only three years in length.[137]

Solar development is rapidly outpacing RPS requirements. The SREC price bubble will collapse when New Jersey solar generation exceeds RPS requirements. According to the Mid-Atlantic Solar Energy Industries Association, an SERC price of $270 would provide a reasonable return on investment for the average solar installation.[138]

PSE&G Solar Programs

In April 2007, PSE&G submitted a plan to the BPU to spur solar development in its service territory.[139] New Jersey's January 2008 Regional Greenhouse Gas Initiative legislation (RGGI) declared that utility involvement in the renewable energy industry was essential to maximizing efficiencies and authorized the BPU to include utility investments in renewable generation in distribution rates.[140]

The BPU approved PSE&G's initial Solar Loan program (SL I) in April 2008. PSE&G was authorized to invest approximately $105 million over two years in a pilot program to finance 30 MW of small-sized customer-owned PV solar installations in its service territory.[141] Under the SL I program, the customers repay the loan by providing the SREC's generated by the installations to PSE&G.[142]

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[134] Clean Energy Program web-site, Renewable Energy, Project Activity Reports, SREC pricing page.

[135] Based on 2009 EY total retail sales of 81,416 GWH and the 2010 EY RPS solar target of 0.221 percent. Total 2009 EY sales source is 2009 Renewable Portfolio Standard Rules, 2009Annual Report, Draft for Public Comment, Appendix 3.

[136] Clean Energy Program web-site, Renewable Energy Committee Meeting Notes, November 15, 2010 and September 21, 2010 meetings.

[137] Mid-Atlantic Solar Energy Industries Association, Comments Regarding the New Jersey Energy Master Plan, September 2010, page 5.

[138] Mid-Atlantic Solar Energy Industries Association, Comments Regarding the New Jersey Energy Master Plan, September 2010, page 2.

[139] Response to Discovery, OC-354

[140] N.J.S.A. 48:3-98.1 (b)

[141] Response to Discovery, OC-354

[142] The residential loans have a term of 10-years. Loans to developers and commercial customers have a 15 years term.

In March 2009, PSE&G submitted its Solar Loan II (SL II) program to the BPU. The SL II program was essentially an expansion of the SL I program. The BPU approved the SL II program in November 2009. The expansion increased the total solar loan capacity authorization to 81 MW.

PSE&G's total investment in the combined solar loan programs will be approximately $248 million once the programs are fully subscribed and the projects are in-service.[143] The loans cover approximately fifty percent of the installation costs. [144] In addition to the loans, customers are eligible for federal tax credits.

SREC prices are a product of supply and demand. Uncertainty about future SREC prices is hindering solar development in New Jersey. The Solar Loan programs include an SREC floor price to reduce that uncertainty. PSE&G credits the higher of the SREC market price or the floor price against the loan balance when the SRECs are transferred to PSE&G.[145]

The solar loan programs are targeted at residential and small commercial customers and are limited to "net metered" solar systems under 500 kv in size. Under the BPU's net metering rules, the solar generation reduces the customer's electricity purchases from PSE&G. If the solar generation exceeds the customer's total electricity usage over a 12 month period, PSE&G purchases the excess at a price equal to the PJM LMP for its zone.[146] As of December 2009, PSE&G had 28.5 MW of net metered solar capacity on its system.[147]

The power produced by the solar loan installations reduces the customer's electricity purchases from PSE&G and PSE&G's electricity purchases from BGS-FP suppliers.

PSE&G requested approval for its Solar 4 All (S4A) Program in February 2009. The S4A program was approved in August 2009. PSE&G was authorized to spend $515 million to install 80 MW of utility-owned solar capacity in its service territory by the end of 2013. The average program capacity cost is $6,432 per kw.

The program consists of two 40 MW segments.

- Centralized solar installations.
- Utility Pole-Top installations.

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[143] PSEG 2009 SEC 10-K Report, page 24.
[144] Response to Discovery, OC-126 and BPU Decision and Order Approving Stipulation, Docket No. EO090302049, November 10, 2009, page 2.
[145] Response to Discovery, OC-1330, PSE&G RGGI Recovery Charge Petition, October 1, 2010, Direct Testimony of Frederick A. Lynk, page 16.
[146] N.J.A.C 14:8-4.3
[147] Clean Energy Program Web-site, Net Metering and Interconnection page, PSE&G net meter report.

The centralized solar segment focuses on 500 kv or larger roof-top solar installations and on-ground "solar farms". The centralized solar segment includes 25 MW on PSE&G owned sites, 10 MW on sites owned by third parties and 5 MW on sites in urban enterprise zones, including publically-owned sites.[148] The installations on PSE&G owned sites include four on-ground solar farms totaling 11 MW.[149]

The utility pole-top segment consists of 200,000 distributed solar systems mounted on utility and street light poles. The pole-top installation is the largest in the world.[150]

PSE&G plans to sell the power produced by the S4A installations into PJM energy and capacity markets.

PSE&G submitted a generation interconnection request to PJM in April 2009 covering 52 MW of solar capacity, including 21.2 MW at nine specific PSE&G owned facilities and 30.8 MW on utility pole-tops throughout PSE&G's service territory. PJM's July 2009 Feasibility/Impact Study Report did not identify any problems and concluded that no transmission system upgrades were required.[151]

Recommendation: PSE&G should publish the results of its solar programs.

PSE&G EMP comments indicate its Solar Loan and Solar-4-All programs should be used as a blueprint for future programs. One way to promote solar generation is to provide information to regulators and market participants about the economics of solar generation.

PSE&G should publish a report describing the results of the programs and the lessons-learned during the implementation process. The report should describe PSE&G's experiences with utility-financing of customer owned systems, including customer preferences and behavior.

The report should also describe PSE&G's experience with utility-owned solar gardens, roof-top systems and pole-top systems. The report should describe the unit costs incurred by PSE&G, the operating performance of the systems and PSE&G's experience with marketing the output of the units.

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[148] Response to Discovery, OC-1330, PSE&G RGGI Recovery Charge Petition, October 1, 2010, Direct Testimony of Frederick A. Lynk, page 9.

[149] Those segments use crystalline solar panel technology. PSE&G Press Release, Construction of PSE&G's Trenton Solar Farm Underway, August 3, 2010.

[150] PSE&G Press Release, Construction of PSE&G's Trenton Solar Farm Underway, August 3, 2010.

[151] PJM website, Active Generation Queues, Queue #V1-030, PSE&G Area Solar Project, Feasibility/Impact Study Report, July 2009.

RPM Capacity Revenue

The July 2009 S4A Settlement Agreement indicates:[152]

> *PSE&G will sell the energy generated by the Solar Systems in the applicable PJM markets. PSE&G will also seek to receive capacity payments from PJM for the Solar Systems, and will do so if the systems qualify...and the benefits...exceed the costs of PJM interconnection and qualification as a capacity resource.*

PSE&G did not bid any S4A capacity in the RPM auctions held in 2009. PJM bidding rules require generation owners to specify the location of their capacity. PSE&G could not bid S4A capacity into the May 2009 and June 2009 auctions, as it had not finalized the installation locations.[153]

In May 2010, PSE&G bid 16 MW of gross solar capacity in the base residual auction for the 2013/2014 delivery year. PJM discounts solar capacity to 38 percent of its gross capacity in the RPM. The actual discounted quantity bid in the auction was 6 MW.[154]

PJM held the first incremental auction for the 2012/2013 delivery year in September 2010. PSE&G bid 18 MW of gross solar capacity in that auction.[155] The following table shows the bid quantity by type.

Table 14-14 - PSE&G Solar Capacity RPM Bid

PSE&G Solar Capacity RPM Bid September 2010 First Incremental Auction 2012/2013 Delivery Year Gross Capacity Before Discount	
Type	**MW**
Centralized Solar	8
Pole-top Solar	10
Total	18
Source: Response to Discovery, OC-1479	

PSE&G's installed solar capacity as of December 31, 2010 is shown below.

[152] BPU Order Approving Stipulation, Docket No. EO09020125, August 3, 2009, Attached Settlement Agreement, paragraph 29.

[153] Matos interview, October 9, 2010. The first incremental auction for the 2011/2012 delivery year was held in June 2009. PJM holds at least two RPM auctions for each delivery year. A base residual auction is held every May for the delivery year starting 36 months later. A first incremental auction is held in September for the delivery year starting 20 months later. RPM rules also provide the option of holding second and third incremental auctions 10 months and 3 months prior to the start of the delivery year. However, those auctions are not held for all delivery years.

[154] Response to Discovery, OC-1479.

[155] The discounted capacity bid was 6.9 MW. Response to Discovery, OC-1479.

Table 14-15 - PSE&G Owned Solar Capacity

PSE&G Owned Solar Capacity As of December 31, 2010	
Type	**MW**
Centralized Solar	13
Pole-top Solar	15
Total	28
Source: PSEG 2010 SEC 10-K Report, page 46	

PSE&G expects to complete an additional 6 MW of solar capacity in the first quarter of 2011. Additional projects are in various stages of negotiation and development.[156]

The 18 MW committed in the September 2010 auction was only approximately seventy percent of the capacity actually installed as of December 2010. The delivery year for that auction starts on June 1, 2012. PSE&G should have bid more capacity in the September 2010 auction.

Recommendation: PSE&G should commit all 40 MW of centralized solar capacity in the RPM auctions held in May, July and September 2011.

PSE&G expects all of the centralized solar capacity to be installed by December 2011. [157]

The following RPM auctions were scheduled for 2011.[158]

- February 2011 Third Incremental Auction for 2011/2012 delivery year.
- May 2011 Base Residual Auction for the 2014/2015 delivery year.
- July 2011 Second Incremental Auction for the 2012/2013 delivery year.
- September 2011 First Incremental Auction for the 2013/2014 delivery year.

All of the centralized solar capacity will be in-service prior to the beginning of the 2012/2013 delivery year. PSE&G should take the steps necessary to commit the full 40 MW of S4A centralized solar capacity in the 2012/2013 and subsequent delivery years.

[156] PSEG 2010 SEC 10-K Report, page 28.

[157] Response to Discovery, OC-1330, PSE&G RGGI Recovery Charge Petition, October 1, 2010, Direct Testimony of Frederick Lynk, Schedule FAL-S4A-2.

[158] PJM website, Reliability Pricing Model, RPM Auction Users Information, RPM Schedule.

Recommendation: PSE&G should consider treating the pole top solar output as a reduction of the BGS-FP load pool.

PSE&G's testimony in the S4A proceeding indicates:[159]

> *If PSE&G is unable to qualify these Solar Systems to sell the output in the PJM energy and/or capacity markets (or if the cost of doing so outweighs the benefits)...the solar output will be applied as a reduction to the load to be served by the BGS-FP suppliers (in PSE&G's load settlement process).*

The July 2009 settlement agreement indicates PSE&G will sell the output of the pole-top units into the PJM energy market. The settlement indicates PSE&G will sell the capacity into the PJM capacity market if it qualifies as a capacity resource and the benefits of doing so exceed the costs. The capacity qualifies as a capacity resource.[160]

PSE&G is currently selling the output of the pole-top units into the PJM energy and capacity markets. Solar tends to generate the most power during hot summer afternoons when peak demand is at its highest point. Treating the output as a reduction in BGS-FP load may be a better alternative. That approach would:

- Reduce BGS-FP prices by improving the BGS-FP load factor and reducing the capacity obligations of PSE&G's BGS-FP suppliers; and
- Reduce the quantity of energy that PSE&G purchases from BGS-FP suppliers.

The February 2011 BGS-FP auction price was $94 per MWH. The reduction in PSE&G's BGS-FP power supply costs might exceed the revenues PSE&G can receive from selling the energy and capacity to PJM.

PJM treats the output of seven non-utility generation (NUG) facilities as reductions in BGS-FP load because the "facilities are too small to be scheduled by PJM."[161] Those "NUG Load Reducers" demonstrate the feasibility of treating the pole top solar units as load reducers. Treating the pole-top units as load reducers is consistent with the distributed nature of the resource.

According to PSE&G, the primary obstacle to treating the pole-top units as BGS-FP load reducers is ratemaking. The solar programs are funded through the RGGI Recovery Charge (RRC). The RRC applies to all distribution customers. Crediting the revenues to the RRC ensures all the customers who pay the RRC

[159] PSE&G petition for approval of the Solar For All program, February 10, 2009, Testimony of Alfredo Matos, page 22.
[160] Response to Discovery, OC-1477.
[161] Response to Discovery, OC-1452. The source for the number of NUG load reducers is Response to Discovery, OC-445, Actual NUG Payments and Receipts schedule for December 2009. NUG purchases are discussed in Chapter 15.

benefit from the output of the units. Treating the units as BGS-FP load reducers would assign all of those benefits to BGS-FP customers.[162]

PSE&G should maximize the total benefits produced by the pole-top units. The allocation of the total benefits between customer classes should be addressed separately. PSE&G should investigate the advantages and disadvantages of using the pole-top units as BGS-FP load reducers. If that produces overall benefits, PSE&G should propose a fair method to allocate those benefits between customer groups.

[162] Response to Discovery, OC-1477.

15. Non-Utility Generation Contracts

The Chapter addresses PSE&G's non-utility generation (NUG) contracts. PSE&G paid $375 million for power under its NUG contracts in 2009.[1]

The findings and recommendations contained in this Chapter are listed below.

Summary of Findings

1. PSE&G purchases power under seven NUG contracts. The three largest account for over 90 percent of PSE&G's NUG costs.
2. PSE&G sells the power received under the NUG contracts to PJM. The NUG contract costs are recovered from ratepayers, net of resale revenue, through the BPU approved Non-Utility Generation Charge (NGC).
3. In 2009, the NUG contract costs exceeded resale revenues by $194 million. The three large contracts accounted for 96 percent of the above-market costs.
4. The three large contracts were originally contracts for the output of cogeneration facilities located in PSE&G's service territory. PSE&G restructured the contracts in 2000 and 2001. The restructurings provided operating flexibility to the sellers in exchange for price reductions and lump-sum payments to PSE&G.
5. The restructurings converted the three large contracts into non-unit specific contracts for the financial settlement of energy and capacity obligations. PSE&G does not physically receive any energy or capacity under the restructured contracts.
6. The three large contracts provide the seller with significant energy scheduling flexibility. That flexibility reduces the revenue PSE&G receives from the financial settlement of the energy. The restructurings also significantly reduce the capacity revenues received by PSE&G. The resale revenues obtained by PSE&G are consistent with the restructured contract terms.
7. The entries to PSE&G's NGC deferral account are consistent with the underlying costs and resale revenues.
8. The opportunities for mitigating PSE&G's above-market NUG costs are limited. The three large contracts expire between March 2013 and April 2016. The relatively short remaining terms limit the opportunities for restructuring the contracts. Because the sellers do not actually deliver power, operational factors do not provide a basis for changing the terms of the three large contracts.
9. PSE&G does not anticipate any significant future mitigation efforts. PSE&G does not have any plans to extend NUG contracts.

[1] Response to Discovery, OC-445

10. PSE&G's management of the NUG mitigation function was adequate during our review period, with one exception. PSE&G's objectives and strategies were reasonable. The mitigation efforts benefitted from adequate management direction and oversight. The financial models used to evaluate alternatives, while simple, were adequate.
11. PSE&G engaged in negotiations in 2008 on two separate matters with the sellers under the three large contracts. PSEG Energy Resources and Trade, LLC (PS ER&T) has extensive commercial relationships with the sellers. In both instances, PSE&G's negotiating team included one of PS ER&T's senior commercial attorneys. That created the risk that PSE&G's interests would be compromised to preserve PS ER&T's business relationships with the sellers. The senior ER&T commercial attorney should have been excluded from the negotiating teams.

Recommendations

1. Attorneys who represent PS Power in power market commercial matters should be excluded from PSE&G's NUG contact negotiating teams.

Background

PSE&G purchases power under seven non-utility generation (NUG) contracts. The three largest contracts are non-unit specific contracts. The four unit-specific contracts are for small renewable energy plants.[2]

The NUG contracts were entered into prior to electric industry restructuring pursuant to the federal Public Utility Regulatory Act of 1978 ("PURPA").[3] PURPA required utilities to buy power from non-utility cogeneration and small renewable energy plants at prices equal to the utility's avoided cost.

PSE&G's NUG contracts were approved by the BPU over a eight year period beginning in August 1984 and ending in June 1992.[4] The contract prices were based on projections of avoided costs that soon proved to be unrealistically high. As a result, prices under the NUG contracts are well above market prices.

PSE&G sells the power received under the NUG contracts into the PJM energy and capacity markets. The excess of the NUG contract costs over the resale revenues is recovered from ratepayers through the BPU approved Non-Utility Generation Charge (NGC).[5]

The 1999 Electric Discount and Energy Competition Act (EDECA) authorized the restructuring of the electric utility industry in New Jersey. EDECA authorized the continued recovery of above market NUG

[2] In addition to the seven contracts, PSE&G also purchases power from seven small NUG suppliers under its Purchased Electric Power (PEP) Tariff. The PEP tariff suppliers are too small to be scheduled by PJM. They are referred to as NUG load reducers because their output is not resold to PJM. Instead, their output is treated as a reduction in the BGS-FP load pool. Response to Discovery, OC-1452.
[3] Response to Discovery, OC-170, NUG Contracts.
[4] Response to Discovery, OC-498, 2002 Deferred Balances Audit Report, page IX-1.
[5] PSE&G Electric Tariff Sheet No. 60.

costs from electric distribution customers and placed an affirmative legal duty on electric utilities to take all reasonably available steps to mitigate the magnitude of the above market costs.[6]

PSE&G's final restructuring order also required PSE&G to mitigate above market NUG costs and to make reasonable efforts to renegotiate its above market NUG contracts.[7]

In 2009, the NUG contract costs exceeded their resale revenues by $194 million. The following table shows the above market costs by contract.

Table 15-1- Cost Above Market

PSE&G NUG Contracts Cost Above Market 2009 - Millions of Dollars			
Contract	Unit Specific	Cost Above Market	Percent Above Market
Cedar Brakes I	No	34	89
Cedar Brakes II	No	58	110
Utility Contract Funding	No	95	131
Wheelabrator Falls	Yes	7	48
Edgeboro	Yes	0	0
Great Falls Hydro	Yes	0	13
Kinsley's Landfill	Yes	0	7
Total		194	107
Source: Response to Discovery, OC-445. Note: Edgeboro was in a force majeure outage for the entire year.			

Non-Unit Specific Contracts

The Cedar Brakes I (CB I), Cedar Brakes II (CB II) and Utility Contract Funding (UCF) contracts accounted for 93 percent of PSE&G's NUG costs in 2009 and 96 percent of its above market NUG costs. Those contracts are non-unit specific contracts for the financial settlement of energy and capacity obligations.

CB I, CB II and UCF are currently wholly-owned indirect subsidiaries of JP Morgan.[8] The contract capacity and termination dates for the CB I, CB II and UCF contracts are shown below.

[6] N.J.S.A. 48:3-50(c)(4); N.J.S.A 48:3-61(f) and N.J.S.A 48:3-61(l).
[7] OC498, 2002 Deferred Balances Audit Report, Attachment 1, page 15.
[8] Response to Discovery, OC-450.

Table 15-2 - CB I, CB II and UCF Contracts - Capacity and Termination Dates

CB I, CB II and UCF Contracts Capacity and Termination Dates		
Contract	MW	Termination
Cedar Brakes I	123	August 2013
Cedar Brakes II	149	March 2013
Utility Contract Funding	195	April 2016
Source: Response to Discovery, OC-170.		

The annual energy quantities (MWH) and prices under the contracts are fixed. The following tables show the scheduled annual energy quantities and price for each of the contracts.

Table 15-3 - CB I Scheduled Energy Deliveries and Fixed Prices

Cedar Brakes I Contract Scheduled Energy Deliveries and Fixed Prices Dollars in Millions			
Year	Energy (MWH)	Price ($/MWH)	Cost
2010	855779	85.76	73
2011	855779	87.67	75
2012	855779	89.63	77
2013	570519	92.43	53
Source: Response to Discovery, OC-170, Contract Exhibits 1 and 2.			

Table 15-4 - CB II Scheduled Energy Deliveries and Fixed Prices

Cedar Brakes II Contract Scheduled Energy Deliveries and Fixed Prices Dollars in Millions			
Year	Energy (MWH)	Price ($/MWH)	Cost
2010	1171424	95.98	112
2011	1171424	99	116
2012	1171424	102.15	120
2013	205400	105.42	22
Source: Response to Discovery, OC-170			

Table 15-5 - UCF Scheduled Energy Deliveries and Fixed Prices

Utility Contract Funding Scheduled Energy Deliveries and Fixed Prices Dollars in Millions			
Year	Energy (MWH)	Price ($/MWH)	Cost
2010	1,666,000	104.21	174
2011	1,666,000	107.43	179
2012	1,666,000	110.76	185
2013	1,666,000	114.24	190
2014	1,666,000	117.93	203
2015	1,666,000	121.78	203
2016	557,000	125.78	70
Source: Response to Discovery, OC-170			

The contracts provide for a fixed annual quantity of energy. The fixed prices apply to all energy scheduled during the year regardless of season, time of day or load conditions.

The contract prices significantly exceed current energy prices in PSEG's transmission zone. The following table shows the average day-ahead energy prices in PSE&G's zone.

Table 15-6 - PSEG Transmission Zone Day-Ahead Energy Market Prices

PSEG Transmission Zone Day-Ahead Energy Market Prices in 2008 to 2010 Dollars per MWH			
Description	2008	2009	2010
Simple Average LMP	80	42	51
Load-Weighted Average LMP	86	44	55
Source: PJM State of the Market Reports; 2009 pages 77 and 80 and 2010 pages 81 and 84.			

Non-Unit Specific Contract Restructuring

The CB I, CB II and UCF contracts were originally contracts for the output of cogeneration units located within PSE&G's service territory. The following table lists those facilities.

Table 15-7 - CB I, CB II and UCF Contracts Generation Source Prior to Contract Restructuring

CB I, CB II and UCF Contracts Generation Source Prior to Contract Restructuring	
Contract	Plant Name
Cedar Brakes I	Newark Bay
Cedar Brakes II	Camden & Bayonne
Utility Contract Funding	Eagle Point
Source: Response to Discovery, OC-170.	

PSE&G restructured the contracts in 2000 and 2001. The restructuring converted them into non-unit specific contracts for the financial settlement of energy and capacity obligations. The original contracts provided for monthly energy escalation as a function of natural gas price. Energy-related payment rates in the amended contracts were fixed for a calendar year with nominal escalation from year to year. The restructuring of the contracts resulted in savings of $666 million from 2003 to 2009.[9]

The restructurings provided the sellers operating flexibility in exchange for price reductions and lump-sum payments to PSE&G. The CB I restructuring set the new fixed energy prices at a level 7.5 percent below the prices forecasted for each of the remaining years in the contract.[10]

The CB II and UCF restructuring set the fixed energy prices at the levels forecasted for each of the remaining years in the contracts. PSE&G received lump sum payments of $64 million from the CB II supplier and $102.5 million from the UCF supplier. The CB II lump sum payment represented a 7.7 percent reduction in the present value of the forecasted payment obligations under the prior contract. The UCF payment represented a 7.6 percent price reduction on a present value basis.[11]

The BPU approved the CB I restructuring in July 2000. The CB II and UCF restructurings were approved in July 2001 and January 2002. The CB I price reductions and the CB II and UCF lump sum payments were credited to the NGC.

The restructured contracts required the sellers to provide PSE&G with capacity credits acceptable to PJM under the PJM Reliability Assurance Agreement. The restructured agreements provided that the capacity credits could be from any source acceptable to PJM.[12]

[9] Response to Discovery, OC-760.
[10] Response to Discovery, OC-1072, BPU Decision and Order, Docket No. EE00040245, July 7, 2000, page 3.
[11] Response to Discovery, OC-1072, BPU Decision and Order, Docket No. EM1050327 (CBII), 24, 2001, page 3 and BPU Decision and Order, EM01080489 (UCF), November 8, 2001, page 3.
[12] Response to Discovery, OC-170, CB I Contract, Article II, Section C.

PJM adopted a new capacity market, called the Reliability Pricing Model (RPM), in June 2007. The RPM provides higher prices for capacity in delivery areas where the ability to import power is constrained by transmission limits. In PJM's prior capacity market, all capacity received the same price regardless of location.

JP Morgan claimed the restructured contracts allowed the capacity to be supplied at any point in PJM. PSE&G claimed the contracts required the supply of capacity in PSE&G's transmission zone.[13] That "RPM dispute" was settled in 2008. Under the settlement, PSE&G receives: (1) non-unit specific capacity credits that can be sold in RPM capacity auctions; and (2) an additional payment of $17 per MW-day for the contract capacity. The BPU approved the settlement in February 2008.[14]

The non-unit specific capacity credits receive the Regional Transmission Organization (RTO) capacity price in PJM's RPM base residual auctions. The RTO price is the price received by capacity located in zones that are not constrained by transmission limits. In the 2008 RPM auction the RTO price applied to all capacity located outside of the constrained Eastern Mid-Atlantic and Southwestern Mid-Atlantic regions.

During the contract restructuring negotiations in 2000 and 2001, PSE&G did not anticipate that PJM would adopt locational capacity prices.[15] PJM introduced the RPM concept to its members in June 2004.[16]

The supplier's obligation to provide energy to PSE&G is settled financially through PJM. PSEG does not take physical delivery of the energy.[17] The capacity obligations are settled financially by reducing the payments PSE&G makes to the suppliers.[18]

Because the energy supply obligations are settled financially, the energy is not associated with any specific power source or metered power flow and the "delivered" quantity in any hour always exactly equals the amount scheduled by the seller.

The financial settlements received by PSE&G reflect the scheduled energy quantities and the day-ahead locational marginal price (LMP) at specific pricing nodes. The pricing nodes are the nodes for the Newark Bay, Camden and Eagle Point generating plants.[19]

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[13] Response to Discovery, OC-496.
[14] Response to Discovery, OC-496, BPU Decision and Order, Docket EE00040245 etc, February 4, 2008.
[15] Robinson and Wodakow interview, March 3, 2010.
[16] Raising the Stakes on Capacity Incentives, PJM's Reliability Pricing Model, James F. Wilson, LECG, LLC, March 14, 2008, page 20.
[17] Response to Discovery, OC-980 and OC-1459.
[18] Response to Discovery, OC-1425, In addition to the bill credits, JP Morgan's upstream suppliers pay the $17 per MW/day consent fee directly to PSE&G. OC-496, page 43.
[19] Response to Discovery, OC-1457.

PSE&G does not receive any ancillary services because the contracts are not unit specific and do not involve the physical delivery of electricity. As a result, PSE&G does not receive any ancillary services resale revenues. For example, PSE&G does not receive any reactive power revenues.[20]

Non-Unit Specific Contracts - Scheduling Flexibility

The CB I, CB II, and UCF contracts provide the sellers with significant energy scheduling flexibility. The contracts contain seasonal and peak period scheduling requirements to prevent the suppliers from loading the energy into hours with low market prices. The scheduling terms differentiate between:

- Summer and non-summer months;
- Peak and off-peak days and hours.

On-peak hours are the 16 hour period between 7 am and 11 pm on weekdays, excluding holidays. All other hours are off-peak hours. The summer months are June through September.

The scheduled energy quantity for each peak hour in a given day must be the same as the quantity scheduled for the other 15 peak hours in that day. Similarly, the scheduled energy quantity for each off-peak hour must be the same as the quantity scheduled for the other off-peak hours in that day.

The following table summarizes the energy scheduling requirements.

Table 15-8 - CBI, CB II and UCF NUG Contracts Delivery Rate Requirements

CB I, CB II and UCF NUG Contracts Delivery Rate Requirements			
Description	CB I	CB II	UCF
Maximum Delivery Rate	150 MW	156 MW	225 MW
Summer On-Peak Aggregate Minimum	40,000 MWH per month	Average 144 MW per hour	Average 200 MW per hour
Summer On-Peak Hourly Minimum	None	130 MW	180 MW
Non-Summer On-Peak Aggregate Minimum	234,000 MWH	349,147 MWH	537,000 MWH
Non-Summer On-Peak Hourly Minimum	46 MW	47 MW	48 MW
Source: Response to Discovery, OC-170			

In 2009, on-peak hours represented 47 percent of the total hours in the year. The contracts effectively require the suppliers to deliver approximately 47 percent of the annual fixed energy quantities during those hours.[21]

[20] Response to Discovery, OC-169 and Robinson interview, March 3, 2010.

[21] The contracts effectively require the following percentage of energy to be delivered during the defined on-peak hours: CB I, 46%; CB II, 47%, UCF 48%.

The scheduling flexibility reduces the revenues PSE&G obtains from the financial settlement of the sellers' energy obligations. The UCF energy settlements reflect the LMP at the pricing node for the Eagle Point power plant. The following table compares the average energy settlement revenues received by PJM for the UCF contract in 2009 to simple average LMP for the Eagle Point pricing node.

Table 15-9 - UCF Energy Resales Prices Compared to Eagle Point Node

UCF Energy Resales Prices Compared to Eagle Point Node Simple Average Day Ahead LMP 2009 - Price per MWH	
Description	Price
UCF Energy Settlement	38.1
Eagle Point LMP	40.4
Source: Response to Discovery, OC-1458 and OC-445.	

The Eagle Point simple average LMP is six percent higher than the average energy settlement price obtained by PSE&G. That reduced the revenues obtained by PSE&G by $3.8 million in 2009.[22]

The sellers schedule the energy to maximize their profitability within the scheduling rules set out under the contract. The seller has an incentive to shift deliveries to hours when PJM prices are low. This is the opposite of the normal dispatch incentives that encourage generators to maximize output when prices are high.

In 2009, the sellers scheduled either the maximum or minimum hourly energy quantity for most hours. The sellers cycled between the maximum and minimum quantities from day-to-day to meet the aggregate scheduling requirements.[23] For example, February 2009 included 20 days with peak period hours.[24] The CB II seller scheduled the maximum quantity of 156 MW for the on-peak hours in 12 of those days and at the minimum quantity of 39 MW for the on-peak hours in the remaining 8 days.[25]

The cycling between minimum and maximum quantities at the sellers option results in the scheduling of disproportionately high delivery quantities in low cost hours.

Non-Unit Specific Contracts - Capacity Credits

Prior to restructuring the CB I, CB II and UCF contracts, PSE&G was entitled to capacity at locations within its transmission zone. After the restructuring, PSE&G receives non-unit specific capacity credits

[22] UCF 2009 energy of 1,669,240 MW times the difference of $2.3 per MWH.
[23] Response to Discovery, OC-445.
[24] February had 20 week days that were not holidays.
[25] Response to Discovery, OC-445.

plus $17 per MW/day. The non-unit specific capacity credits are paid the RTO price determined in the annual RPM base residual auctions.

The RPM capacity price applicable to the PSE&G zone is considerably higher than the RTO price in some years, as shown on the following table.

Table 15-10 - RPM Capacity Prices RTO Versus PSE&G Zone

RPM Capacity Prices RTO Versus PSE&G Zone Dollars per MW/Day				
Delivery Year	2010 / 2011	2011 / 2012	2012/ 2013	2013 / 2014
PSE&G (EMAAC)	174	110	140	245
RTO	174	110	17	28
Difference	0	0	123	217
Note: EMAAC is the Eastern Mid-Atlantic Area (Reliability) Council Region.				
Source: PJM website; RPM Base Residual Auction Results. Note: price for PSE&G North was $185 in 2012/2013 auction.				

The CB I and CB II contracts expire in August and March 2013, respectively. The UCF contract expires in April 2016. The additional $17 per MW/day capacity payment will only offset a relatively small portion of the locational difference in capacity prices in the 2012/2013 and 2013/2014 delivery years.

The capacity revenues received by PSE&G were $12.8 million lower in 2008 and $8.0 million lower in 2009 than the amount PSE&G would have received if the capacity credits had earned the RPM price applicable to PSE&G's transmission zone.[26]

Non-Unit Specific Contracts - JP Morgan 2008 Proposal

In April 2008, JP Morgan proposed replacing the market prices used to determine the financial settlement for the energy "resale" with a schedule of fixed annual prices.[27]

The parties discussed various permutations of the proposal through February 2009, when the falling energy prices dampened interest in that approach.[28] The dramatic fall in energy prices resulted in an inability to agree on fixed prices for future years.[29]

[26] Response to Discovery, OC-445 and PJM RPM Auction Results reports for the 2007/2008 and 2008/2009 delivery year base residual auctions.
[27] Response to Discovery, OC-450 and Robinson and Wodakow interview, March 3, 2010.
[28] Response to Discovery, OC-450.
[29] Robinson and Wodakow interview, March 3, 2010.

Unit-Specific Contracts

PSE&G has four unit specific NUG contracts. Those contracts are relatively small as shown on the following table.

Table 15-11 - Unit Specific NUG Contracts

Unit Specific NUG Contracts 2009 - Dollars in Millions				
Contract	Type	MW	Cost	Cost/MWH
Wheelabrator Falls	Solid Waste	37	23	67
Edgeboro	Landfill Biogas	5	0	0
Great Falls	Hydro	2	1.3	49
Kinsley's Landfill	Landfill Biogas	1	0.4	46
Total		45	25	65
Source: Response to Discovery, OC-197 and OC-445. Capacity is RPM capacity as of December 2009.				

Wheelabrator Falls operates a municipal solid waste facility in Montgomery County, Pennsylvania. The Wheelabrator Falls contract expires on July 31, 2014.[30] The Edgeboro contract was in an extended outage for all of 2009.

Unit Specific Contracts - PS ER&T Scheduling Agreement

PSE&G entered into a agreement with ER&T effective November 4, 2003 for the scheduling of capacity and energy from PSE&G's NUG contracts at PJM.

Prior to the implementation of RPM in June 2007, ER&T bid the NUG capacity into the PJM capacity markets. ER&T no longer submits the capacity bids. PSE&G bids the NUG contracts directly into the RPM auctions without assistance from ER&T.[31] PSE&G's scheduling agreement with ER&T was amended in January 2010 to eliminate the provisions related to bidding capacity. The revised agreement was made retroactive to the RPM adoption date of June 1, 2007.[32]

ER&T acts as PSE&G's scheduling agent at PJM for the resale of the energy obtained from the unit-specific NUG contracts.[33] ER&T does not schedule the CB I, CB II and UCF contracts because the energy provided by those contracts is financially settled.[34]

[30] Response to Discovery, OC-186, SBC-NGC 2007 BPU proceeding, Request S-PS-NUG-4.
[31] Response to Discovery, OC-1268.
[32] Response to Discovery, OC-1268.
[33] Response to Discovery, OC-502.
[34] Response to Discovery, OC-980.

Unit Specific Contracts - Resale Revenue

PJM operates two energy markets, the day-ahead energy market and the real-time balancing market. Energy bid into the day-ahead energy market must be scheduled by noon on the day before the delivery day. The real time balancing market is used to price deviations from the generation and demand scheduled in the day-ahead market. Energy sold in the real-time balancing market does not have to be scheduled in advance.

PSE&G does not sell the output of the unit specific contracts in the day ahead market. Instead, it sells the output at real-time prices in the balancing market. PSE&G provided the following explanation for that policy.[35]

> *Each of these facilities is a unit contingent resource that uses some type of renewable resource (e.g. hydro, landfill gas or municipal solid waste) and therefore cannot have a firm delivery obligation. As such the units are scheduled...as "must-run" and the output from them is sold into the balancing market at real-time price.*

PSE&G has not prepared any analysis of the costs or benefits of selling the power into the day-ahead market instead of the real-time market.[36] However, the prices in the two markets are similar. The following table compares simple average real-time and day-ahead prices for the PSE&G zone over the past three years.

Table 15-12 - Comparison of Day-Ahead and Real Time Prices

Comparison of Day-Ahead and Real Time Prices PSE&G Zone Simple Averages 2008 to 2010 - Price per MWH			
Description	2008	2009	2010
Day-Ahead Market	79.8	41.8	50.9
Real-Time Balancing Market	79.1	41.3	51
Difference	0.7	0.5	-0.1
Source: PJM State of Market Reports, Volume 2 (2009 pages 77 and 65 and 2010 pages 71 and 81)			

The following table compares the average resale energy prices for the unit-specific contracts to the simple average real-time price in PSE&G's zone for 2008 and 2009.[37]

[35] Response to Discovery, OC-980.
[36] Response to Discovery, OC-1408 and OC-1409.
[37] The simple average LMP is the appropriate basis for evaluating the prices obtained for energy produced by must-run renewable generation sources.

Table 15-13 - Unit Specific NJG Contracts Energy Resales Prices

Unit Specific NUG Contracts Energy Resales Prices Compared to PSEG Zone Real Time Price 2008 and 2009 - Price per MWH		
Description	2008	2009
Unit Specific NUG Contracts	74.3	39.5
Real-Time Market - Simple Average	79.1	41.3
Difference	-4.8	-1.8
Source: 2009 PJM State of Market Report, page 77 and 65. Response to Discovery, OC-445.		

Wheelabrator accounted for 90 percent of the unit specific generation in 2009. The resale price for that energy reflects the real-time LMP at the Wheelabrator pricing node. Differences between the prices for individual pricing nodes and the zonal average price are expected.

Overland recalculated the capacity revenues obtained by PSE&G for 2008 and 2009. The revenues are consistent with the RPM capacity market prices for the plant locations. The energy and capacity revenues PSE&G obtained from the resale of power from the unit specific contracts were reasonable in 2008 and 2009.

Edgeboro Restructuring

The Edgeboro facility suspended operations in October 2008 due to a partial collapse of its landfill gas gathering system. The owners of the Edgeboro facility submitted a force majeure claim. PSE&G disputed the claim, indicating the damage to the gas gathering system could have been avoided by improvements to the system. The force majeure claim was settled in 2010. The settlement provides for the assignment of the contract to a new operator, the installation of new equipment, revisions to the pricing terms, an extension of the contract and $1.5 million in payments to PSE&G over three years.[38]

The prior agreement was scheduled to terminate in October 2012. The revised agreement terminates seven years after the commercial operation date of the new facilities. Under the revised pricing terms, PSE&G will pay for energy based on PJM spot market prices. PSE&G will no longer receive or pay for capacity under the revised agreement.

Under the prior arrangement, PSE&G received the renewable energy certificates (RECs) generated by the facility.[39] Under the revised agreement, the RECs belong to the supplier. The $1.5 million received by PSE&G reflects the value of the RECs. The payment was credited to the NGC deferral account.[40]

[38] Response to Discovery, OC-1381.

[39] The RECs were distributed to PSE&G's BGS-FP suppliers. Response to Discovery, OC-188. That reduced BGS-FP prices and passed the value of the credits through to BGS-FP customers.

[40] Response to Discovery, OC-1381, BPU Order, Docket No. EO10080538, October 5, 2010, page 3.

PSE&G is not expected to incur any above market costs under the revised Edgeboro agreement. The BPU approved the Edgeboro settlement and contract restructuring in October 2010.[41]

NGC Cost Deferral

Overland reviewed the entries to PSE&G's Non-Utility Generation Charge (NGC) deferral account for 2009.[42] The NUG costs charged to the account accurately reflected the payments made to the suppliers.

PSE&G has a separate sub-account with PJM that tracks the credits and charges associated with reselling the NUG power.[43] The resale revenues credited to the NGC deferral accurately reflect the revenues obtained from PJM.

Mitigation Efforts

PSE&G incurred above market costs under the CB I, CB II, UCF and Wheelabrator contracts in 2009. The CB I and CB II contracts expire in 2013. The Wheelabrator contract expires in July 2014. The UCF contract expires in April 2016. The relatively short remaining terms of the contracts limit the opportunity for mitigating above market costs.

The CB I, CB II and UCF contracts do not result in the physical delivery of power. The sellers receive fixed annual payments from PSE&G. The fixed payments are partially offset by a market-based amount calculated by applying actual PJM day-ahead energy prices to scheduled energy quantities. The seller schedules the energy within the rules set out in the contract. Because the seller does not actually deliver power, operational factors do not provide a basis for changing the contract terms.

Any reduction in the fixed annual payments would negatively impact the value of the contracts to the seller. Similarly, changing the scheduling rules to increase the market-based offset would negatively impact the seller.

PSE&G is at risk for future market price volatility, because the market-based offset reflects spot market energy prices. The parties discussed the option of reassigning that market-based risk to the sellers in 2008 and 2009. The sellers would logically demand a risk premium for assuming additional risk.

Market prices are very difficult to predict. Under the current arrangements, the NGC rates charged to customers decrease if market prices increase. The BGS rates charged to customers move in the opposite direction.

Fixing the prices used to calculate market-based offset is not an attractive strategy because of the required risk premium and the increase in price volatility for end-use customers.

[41] Response to Discovery, OC-1381, BPU Order, Docket No. EO10080538, October 5, 2010.
[42] Response to Discovery, OC-185.
[43] Response to Discovery, OC-177.

Another potential mitigation strategy is to accelerate payments to the sellers in exchange for price reductions. The seller might be willing to trade a significant price reduction in exchange for accelerated cash flow if the seller's alternative sources of capital have a high cost.

Given PSE&G's credit quality and the low risk of contract non-performance, the seller may be able to assign the contract cash flow to financial investors in exchange for a lump-sum cash payment. A mitigation strategy based on cost-of-capital differentials may not be attractive because of potential competition from financial investors.

Wheelabrator has not shown any interest in restructuring its contract.[44] Municipal solid waste generators have a reputation for being unwilling to restructure NUG contracts.[45]

PSE&G does not anticipate any significant future mitigation efforts. PSE&G does not have any plans to extend any of its NUG contracts. The Edgeboro contract restructuring was the only significant NUG related matter addressed in 2010.[46]

Mitigation Management

PSE&G's Manager - NUG Contracts is responsible for identifying and evaluating NUG mitigation options with the assistance of his supervisor, the Director of BGS/BGSS Services. Overland interviewed both of those individuals and reviewed PSE&G's mitigation efforts over the past four years. PSE&G's management of the NUG mitigation function was adequate during the review period, with one exception.

PSE&G's NUG mitigation objectives and strategies were reasonable. The restructuring efforts benefitted from adequate management oversight. The financial models used to evaluate alternatives, while simple, were adequate.

The Manager of NUG contracts has many years of experience with the NUG contracts, dating back to the CB I, CB II and UCF contract restructurings in 2000 and 2001.[47]

PSE&G's negotiating teams for the RPM dispute and 2008 JP Morgan proposals were very similar. The RPM dispute negotiating team consisted of:

[44] Robinson interview, March 3, 2010.
[45] Response to Discovery, OC-498, March 2005 Deferred Balances Audit Report, page VII-4.
[46] Robinson and Wodakow interview, March 3, 2010.
[47] Wodakow interview, March 3, 2010.

Table 15-14 - PSE&G NUG Contract Mitigation RPM Dispute Negotiating Team

PSE&G NUG Contract Mitigation RPM Dispute Negotiating Team		
Name	Title	Role
Fredrick Lark	Vice President, Business Analysis	Co - Executive
Shawn Leyden	PSEG Vice President Law - Commercial	Co - Executive and Legal Advice - Commercial
Anthony Robinson	Director BGS/BGSS	Analyst
Seymour Wodakow	Manager NUG Contracts	Analyst
Kenneth Carretta	General Regulatory Markets Counsel	Regulatory Advice
Source: Response to Discovery, OC-497		

Mr. Lark and Mr. Leyden attended all negotiating sessions. PSE&G retained a consultant after the negotiations were completed to assist in obtaining BPU approval for the settlement. The consultant, Robert Chilton, was formerly the director of the BPU's Division of Energy.[48]

The negotiations required judgement regarding future locational price differentials in the RPM capacity market. The negotiating team's qualifications for providing that judgement were questionable.

PSE&G did not anticipate the implementation of location-based capacity markets when it restructured the CB I, CB II and UCF contracts in 2000 and 2001. Given that experience, it would have been advisable to include a capacity market expert on the team.

PSE&G's team for the 2008 JP Morgan proposal is shown below.

Table 15-15 - PSE&G NUG Contract Mitigation - 2008 JP Morgan Energy Pricing Proposal

PSE&G NUG Contract Mitigation 2008 JP Morgan Energy Pricing Proposal		
Name	Title	Role
Fredrick Lark	Vice President, Business Analysis	Executive
Seymour Wodakow	Manager NUG Contracts	Analysis and Support
Anthony Robinson	Director - BGS/BGSS Services	Policy Support
Robert Chilton	Gable Associates, Executive VP	Economic Analysis
Shawn Leyden	PSEG Vice President Law - Commercial	Legal Advice
Kenneth Carretta	General Regulatory Markets Counsel	Regulatory Advice
Source: Response to Discovery, OC-497 and Wodakow/Robinson interview		

[48] Gable Associates web-site.

Mr. Lark attended all negotiating sessions with JP Morgan.[49] Evaluating JP Morgan's proposal required judgement concerning future spot market energy prices. Mr. Chilton provided those judgements.[50]

Mr. Leyden represents PS Power in many legal matters. In 2008, Mr. Leyden worked 1,348 hours on ER&T Trading Agreements. In 2008, 86 percent of Mr. Leyden's labor costs were directly assigned to PS Power. In 2009, 74 percent of Mr. Leyden's labor costs were directly assigned to PS Power.[51]

Mr. Leyden was one of two co-executives directing the RPM dispute negotiations. The central issue in the RPM dispute was the legal interpretation of the capacity obligation terms contained in the original contracts. Mr. Leyden was responsible for providing that legal interpretation to PSE&G. Placing one of ER&T's senior attorneys in a policy making role in the RPM dispute was inappropriate.

CB I, CB II and UCF were indirect subsidiaries of Bear Sterns in 2007. The RPM negotiations involved Bear Sterns and its upstream suppliers. The upstream supplier for the CB I and CB II contracts was Constellation Energy Commodities Group. The upstream suppliers for the UCF contract were El Paso Marketing and Morgan Stanley Capital Group.[52] The upstream suppliers actively participated in the negotiations and were parties in the BPU proceeding for approval of the RPM settlement. PSE&G entered into individual consent fee agreements with each of the upstream suppliers. The upstream suppliers pay the $17 per MW/day consent fees directly to PSE&G.[53]

Constellation Energy Commodities was ER&T's second largest customer in 2007. ER&T's FERC Electric Quarterly reports show $366 million in energy sales from ER&T to Constellation in 2007.[54]

Including one of ER&T's senior commercial attorneys on the RPM dispute negotiating team created the risk that PSE&G's interests would be consciously or unconsciously compromised to preserve ER&T's business relationship with Constellation.

All of PSE&G's NUG costs and resale revenues are passed through to customers via the NGC. The dollar amount of the consent fee extracted from the sellers did not impact PSE&G's net income. PSEG's net income is directly impacted by the terms of ER&T's business arrangements with Constellation. PSEG had an economic incentive to exchange lower consent fees for favorable terms in ER&T's other business arrangements with the suppliers.

[49] Robinson and Wodakow interview, March 3, 2010.
[50] Robinson and Wodakow interview, March 3, 2010.
[51] Response to Discovery, OC-698.
[52] Response to Discovery, OC-496.
[53] Response to Discovery, OC-496, page 34 of 143.
[54] FERC website, Electric Quarterly Reports, Summaries, ER&T Energy Sales and Bookouts by Customer. PJM was ER&T's largest customer in 2007.

CB I, CB II and UCF are currently indirect subsidiaries of JP Morgan. Mr. Leyden provided legal advice concerning JP Morgan's 2008 proposal to set a fixed schedule of energy resale prices for those contracts. JP Morgan Energy Ventures was one of ER&T's ten largest customers in the first six months of 2009.[55]

Recommendation: Attorneys who represent PS Power in power market commercial matters should be excluded from PG&E's NUG contact negotiating teams.

The BPU does not have access to ER&T's agreements with its customers and suppliers. The BPU does not have any way of knowing if ER&T is involved in business disputes with NUG contract counter parties such as Constellation or JP Morgan. The BPU cannot audit those transactions or disputes to identify package deals that subordinate the interests of PSE&G's customers to the interests of PSEG's shareholders.[56]

Structural separation is the only practical way to protect ratepayers from the risk that their interests will be compromised to advance the interests of merchant affiliates. Mr. Leyden should not have been included on the RPM dispute and 2008 JP Morgan proposal negotiating teams.

PSE&G's NUG contract negotiating teams should exclude attorneys that who have spent more than 10 percent of their time representing PS Power in power market commercial matters in the prior twelve months. [57]

[55] FERC website, Electric Quarterly Reports, Summaries, ER&T Energy Sales and Bookouts by Customer.

[56] Package deals exchange terms that are unfavorable to the utility for terms that are favorable for a non-regulated affiliate. For example, requiring the utility to purchase goods at an above market prices in exchange for the supplier providing goods to a non-regulated affiliate at below market prices. Or, an agreement by a customer of a non-regulated affiliate to pay above market prices to the non-regulated affiliate in exchange for the utility's agreement to drop a legal claim against the customer.

[57] PS ER&T is a subsidiary of PS Power. The scope of the recommendation includes PS Power and its direct and indirect subsidiaries. This recommendation is expected to have limited applicability because major NUG contract negotiations are not expected prior to the expiration of the contracts.

16. Power Supply and Transmission Affiliate Issues

PSEG's merchant power business is conducted through PSEG Power (PS Power). PS Power is an intermediate holding company that owns the following direct principal subsidiaries.

- PSEG Fossil - owns fossil fueled power plants (PS Fossil);
- PSEG Nuclear - owns interests in three nuclear power plants (PS Nuclear); and
- PSEG Energy Resources & Trade - purchases all the power generated by PS Fossil and PS Nuclear, markets the power and engages in energy trading activities (ER&T).

PS Power accounted for 75 percent of PSEG's consolidated net income in 2009 and 73 percent in 2010.[1] PSE&G purchases power from ER&T and provides transmission service to ER&T.

The joint ownership of a regulated electric utility and merchant power companies creates the risk that: (1) utility interests will be subordinated to the interests of the merchant affiliates; and (2) utility resources will be used to provide an unfair competitive advantage to the merchant affiliates.

PSE&G's policy is to comply with FERC and BPU affiliate rules and regulations. PSEG's Standards of Integrity indicate all employees are expected to understand and comply with BPU and FERC affiliate rules and regulations. Although no violation of the respective standards were found, the Auditors recommend that the BPU periodically review the current rules to determine whether any additional safeguards are needed to ensure protection of PSE&G's ratepayers from the potential for PSE&G to provide an undue preference to PSEG Power as a result of the corporation's structure.

This chapter addresses affiliate issues pertaining to power supply and transmission. Affiliate issues pertaining to generation interconnection and non-power goods and services are discussed in Chapter 2.

Summary of Findings

1. PS Power was highly profitable over the period of our review (2007 to 2010). PS Power's return on equity averaged 27 percent over that four year period. PS Power owns 13,548 MW of generating capacity. Approximately 90 percent of that capacity is located within PJM. Nuclear plants account for about 60 percent of PS Power's net generation in PJM. PS Power's competitive advantages include having a low-cost generating fleet with many units located near large load centers east of PJM transmission constraints.

[1] PSEG web-site, PSEG 2010 Earnings Release, February 22, 2011, Attachment 3.

2. PS Power owns 90 percent of the generating capacity located in PSE&G's transmission zone and 33 percent of the capacity located within PJM's Eastern Mid-Atlantic Area Council (EMAAC) region .

3. Market power is a significant concern in PJM energy and capacity markets. PJM's market power mitigation rules are critical to protecting consumers from market power abuse

4. The BGS auction process includes several valuable safeguards that protect ratepayers against affiliate abuse, including competitive bidding, independent process management, standard product definition, equal access to information for all bidders, price-only bid evaluation criteria and BPU oversight.

5. PS Power provides approximately 36 percent of New Jersey's BGS-FP power supply. New Jersey BGS-FP (Basic Generation Service - Fixed Pricing) sales accounted for about 40 percent of PS Power's net generation in 2009. PS Power provided 43 percent of PSE&G's BGS-FP power supply in 2009.

6. The number of BGS-FP tranches awarded to PS Power is consistently close to the state-wide and PSE&G load caps. The magnitude and persistence of PS Power's BGS-FP market share raises concerns about the competitiveness of the underlying market.

7. PJM control over transmission significantly reduces the risk of affiliate abuse in transmission operations and planning. PJM's control over transmission planning, tariff administration, operations and the generation interconnection process substantially reduces the risk that transmission owners will provide an unfair competitive advantage to their generation affiliates.

8. According to PSE&G, the BPU Affiliate Relations Rules do not apply to PS Power because it does not offer competitive services to retail customers in New Jersey. According to PSE&G, the FERC's Affiliate Restrictions do not apply to PSE&G because it does not have any captive customers.[2]

9. Functional separation is a key regulatory safeguard for managing the incentives created by the joint ownership of regulated and non-regulated operations. The FERC Transmission Standards require the separation of transmission and marketing function employees. PSEG has written plans and procedures for ensuring the functional separation of PSE&G Transmission Function employees from PSEG Merchant Function employees, as required by the FERC Standards of Conduct. However, PSE&G has no written plans or procedures for ensuring the operational separation of most PSE&G and PS Power employees.

[2] 134 FERC 61,138 (FERC Feb. 25, 2011)

10. PS Power's access to PSE&G's Energy Management System (EMS) is limited to information about PS Power generating plants and PJM system data that is available to all generators. PSE&G charges 18.75 percent of the costs of the EMS to PS Power. The allocation factor is based on engineering judgment. The basis for the allocation factor is poorly documented. Basing affiliate cost allocations on engineering judgment is problematic.

11. In the absence of appropriate safeguards, PSE&G's BGSS Requirements Contract with PS Power creates the potential for significant affiliate issues as it creates the risk that BGSS customers will be required to subsidize PS Power's fuel costs.

12. PSE&G provides gas transportation services to PS Power at discounted rates. PSE&G apparently provided those services for many years without a written contract and without requiring PS Power to demonstrate the need for the discounts. That demonstrates a lack of appreciation for and commitment to affiliate transactions safeguards. Issues related to discounted rates for gas-to-electric generation have been resolved as part of a recent BPU proceeding.

13. PJM market rules have a significant impact on BGS prices. PSEG directs and controls the management of its subsidiaries including PSE&G. PSEG's policy is to take one unified corporate position at PJM and FERC. The unified positions are developed by the PSEG Services Corporation Law Department. PSEG has an inherent economic incentive to adopt unified corporate positions that favor merchant generation interests.

14. PSEG tends to caucus with generation interests at PJM and FERC. PSEG usually votes for the positions favored by a majority of generation owners at PJM. PSEG's FERC positions frequently coincide with those taken by generation interests. The alignment of PSEG and generation owner positions raises concerns that the utility's positions are being shaped to advance the interests of PS Power.

15. The process of developing PSEG's unified corporate positions includes significant commingling of utility and merchant generation interests and views. PSE&G defers to PS Power's market expertise on PJM issues because of its superior knowledge of the markets. Relying on PS Power for expertise on market issues provides it with an opportunity to shape utility positions to advance merchant interests.

16. PSEG balances the interests of the utility's distribution customers and PS Power when it develops the unified corporate positions. That balancing process is completely undocumented. The lack of contemporaneous documentation impedes regulatory oversight.[3]

[3] PSE&G represents it has a process requiring that minutes be kept for certain cross-function policy team meetings, but denied Overland access to most of those minutes based on attorney-client and attorney work product privilege.

Recommendations

1. PSE&G and PS Power should develop compliance plans for ensuring utility and PS Power personnel operate independently to the maximum extent practical.

2. PSE&G should track meetings jointly attended by utility and PS Power personnel.

3. PSE&G should develop a compliance plan to limit PS Power's access to non-public utility information.

4. PSE&G should track non-public utility information provided to PS Power.

5. PSE&G should document the basis for the EMS cost allocation factor.

6. PSE&G should review the advantages and disadvantages of outsourcing BGSS Gas procurement to ER&T.

7. PSE&G should develop and advocate separate utility positions on PJM and FERC issues. . . . .

8. If PSEG continues to vote a unified corporate position at PJM, it should join the generation owners sector.

Affiliate Agreements

PSE&G's agreements with affiliates related to power supply and generation are listed below.

Table 16-1 - PSE&G Affiliate Power Supply Related Agreements

PSE&G Affiliate Power Supply Related Agreements	
Short-Hand Title	Description
BGS-FP Master Supply Agreements[4]	ER&T sells power to PSE&G for BGS-FP customers
Interconnection Agreements[5]	PSE&G provides interconnection services to PS Power
Verbal Gas Transportation Agreement [6]	PSE&G provides gas transportation services to PS Power Generating Stations
Service Agreement[7]	PSE&G and PS Power provide non-power goods and services to each other.
Memorandum of Understanding for EMS access[8]	PSE&G provides ER&T with access to its Energy Management System.
Agreement for Scheduling NUG Resources[9]	ER&T provides power scheduling services to PSE&G
BGSS Requirements Contract[10]	ER&T provides gas transportation, storage and commodity supply to PSE&G
Source: Response to Discovery, OC-61, OC-482, OC-705, and OC-735.	

[4] Response to Discovery, OC-61.
[5] Response to Discovery, OC-705.
[6] Response to Discovery, OC-852.
[7] Response to Discovery, OC-735.
[8] Response to Discovery, OC-61.
[9] Response to Discovery, OC-61.
[10] Response to Discovery, OC-482. BGSS is the default service for gas distribution customers that have not selected a third party retail supplier.

The Interconnection and Service agreements are discussed in Chapter 17. The NUG (Non-Utility Generator) scheduling agreement is discussed in Chapter 15.

PS Power Generation Capacity

The following table shows PS Power's generating capacity by regional transmission organization.

Table 16-2 - PS Power Generating Capacity By RTO

PS Power Generating Capacity By RTO	
RTO/ISO[11]	MW
PJM	11,807
New England	995
New York (NYISO)	746
Total	13,548
Source: PSEG 2009 10-K, page 39[12]	

The New England capacity consists of the Bridgeport Harbor and New Haven plants in southwestern Connecticut.[13] PSEG was recently selected by the Connecticut Department of Public Utility Control to construct 130 MW of combustion turbine units at New Haven at an estimated cost of $135 million. The project is expected to be in service by June 2012.[14]

PS Power only has one plant in NYISO, the 746 MW Bethlehem combined cycle plant completed in 2005. Prior to 2011, PS Power owned 2,000 MW of generating capacity in Texas. PS Power announced the sale of the 1,000 MW Guadalupe plant and the 1,000 MW Odessa plant in January 2011.[15] Once the sales are completed, PS Power will not own any capacity in Texas.

PS Power's PJM capacity consists of 9,914 MW in New Jersey and 1,893 MW in Pennsylvania. The following table shows the PJM capacity by type.

[11] RTO - Regional Transmission Organization; ISO - Independent System Operator

[12] Adjusted to reflect the 2011 sale of 2,000 MW of capacity located in Texas.

[13] New Haven is a 448 NW oil fired steam unit completed in 1975. Bridgeport consists of two coal fired steam units totaling 526 MW completed in 1961 and a 21 MW combustion turbine completed in 1967. PSEG Market Power Filing, FERC Docket ER99-3151, January 14, 2008, Appendix C.

[14] PSEG, Third Quarter 2010 SEC 10-Q Report, page 29.

[15] PSEG press release, PS Power Enters into Agreement to Sell Texas Assets, January 13, 2011. Both are combined cycle plants completed in 2001.

Table 16-3 - PS Power PJM Generating Capacity by Type

PS Power PJM Generating Capacity by Type	
Type	MW
Nuclear	3,662
Steam	2,797
Combined Cycle	2,408
Combustion Turbine	2,740
Pumped Storage	200
Total	11,807
Source: PSEG 2009 10-K, page 39.	

PS Power's pumped storage capacity consists of a 50% interest in the Yards Creek station. Yards Creek was completed in 1965 and is operated by Jersey Central Power and Light.

PJM Nuclear Capacity

The following table shows PSEG's nuclear capacity.

Table 16-4 - PS Power PJM Nuclear Capacity

PS Power PJM Nuclear Capacity			
Units	State	Capacity	Completed
Hope Creek	NJ	1,199	1986
Salem 1 & 2	NJ	1,346	1977 & 1981
Peach Bottom 2 & 3	PA	1,117	1974
Total		3,662	
Source: PSEG 2009 10-K, page 39 and PJM 2009, Load, Capacity and Transmission Report.			

PS Nuclear operates Hope Creek and Salem. Peach Bottom is operated by Exelon.[16] PS Power implemented several projects in recent years to increase the capacity of the nuclear plants.

PS Nuclear submitted an early site permit application with the Nuclear Energy Regulatory Commission in May 2010 as part of its ongoing efforts to explore the possibility of building another nuclear unit adjacent to the Hope Creek and Salem Nuclear plants.[17]

[16] PSEG web-site, PS Nuclear, Peach Bottom page.

[17] PSEG press release, PSEG Power and PSEG Nuclear File Early Site Permit Application, May 25, 2010.

PJM Steam Capacity

PS Power's PJM steam capacity is shown below by plant.

Table 16-5 - PS Power PJM Steam Capacity

PS Power PJM Steam Capacity					
Plant	State	Capacity	Fuel	Mission	Completed
Hudson	NJ	930	Coal/gas	Load Following	1964 & 68
Mercer	NJ	638	Coal	Load Following	1960 & 61
Sewaren	NJ	453	Gas	Load Following	1948 to 51
Keystone	PA	391	Coal	Base Load	1967 & 68
Conemaugh	PA	385	Coal	Base Load	1970
Total		2797			

Source: PSEG 2009 10-K, page 39 and PJM 2009 Load, Capacity and Transmission Report.

PS Power is implementing significant environmental upgrades at the coal-fired Hudson and Mercer plants at a total cost of $950 to $1,050 million. PSEG spent $932 million on the projects through September 30, 2010.[18]

In December 2004, PS Power notified PJM of its plans to retire the Sewaren steam units and the 383 MW gas-fired Hudson Unit One.[19] The Sewaren retirement notice expired and the Sewaren steam units are no longer scheduled for retirement. Hudson Unit One is currently scheduled for retirement in September 2012.[20]

Hudson Unit One is designated as a reliability must run (RMR) unit by PJM. RMR units are units at-risk for retirement that are needed for reliability purposes. RMR units are paid cost-of-service rates by PJM to ensure they remain in service. The RMR payments are included in the transmission rates charged to load serving entities. The Sewaren steam units were RMR units from September 2005 through August 2008.[21]

PJM Combined Cycle Capacity

All of PS Power's PJM combined cycle capacity is located in New Jersey.

[18] PSEG Third Quarter 2010 SEC 10-Q Report, page 25. The Hudson environmental upgrades are for Unit 2.
[19] BPU Decision & Order, Docket No. ER05040368, June 22, 2005.
[20] PJM web-site, Planning, Generation Retirements, Generation Retirement Summaries, Pending Deactivation Requests.
[21] Response to Discovery, OC-1125 and BPU Decision & Order, Docket No. ER05040368, June 22, 2005.

Table 16-6 - PS Power PJM Combined Cycle Capacity

PS Power PJM Combined Cycle Capacity			
Plant	Capacity	Mission	Completed
Bergen	1178	Load Following	1995 & 2002
Linden	1230	Load Following	2006
Total	2408		
Source: PSEG 2009 10-K, page 39 and PJM 2009, Load, Capacity and Transmission Report and PSEG.com, Linden and Bergen pages.			

Bergen Unit 1 was built in 1959. PSE&G redeveloped Unit 1 as a combined cycle unit in 1995. PSE&G retired 436 MW of oil-fired steam units at Linden after it completed the two new combined cycle units in 2006.

On January 15, 2008, PS Power advised PJM that it intended to disconnect the 550 MW Bergen Unit Two from PJM and export the unit's output to New York City through a proposed transmission line known as the Cross Hudson Project.[22] PS Power hoped to sell the power to the New York Power Authority (NYPA). PS Power withdrew its deactivation notice when NYPA selected another supplier. PS Power indicated it would continue to pursue opportunities to sell power in the NYISO market via the Cross Hudson Project.[23]

[22] BPU Notice of Intervention and Protest, FERC Docket EL08-35-000, February 19, 2008.
[23] Answer of PSEG ER&T and PS Fossil, FERC Docket EL08-35-000, May 12, 2008.

PJM Combustion Turbine Capacity

All of PS Power's PJM combustion turbine capacity is located in New Jersey.

Table 16-7 - PS Power PJM Combustion Turbine Capacity

PS Power PJM Combustion Turbine Capacity			
Plant	Capacity	Fuel	Completed
Essex	617	Gas	1971 & 1990
Edison	504	Gas	1971
Kearny	446	Gas	1967 to 2001
Burlington	553	Gas	1967 to 2000
Linden	336	Gas	1995 & 2000
Mercer	115	Oil	1967
Sewaren	105	Oil	1965
Bergen	21	Gas	1967
National Park	21	Oil	1969
Salem	22	Oil	1971
Total	2,740		
Source: PSEG 2009 10-K, page 39 and PJM 2009, Load, Capacity and Transmission Report.			

PS Power retired 731 MW of generating capacity at Burlington, Kearny, Bayonne and Hudson in 2003 through 2006.[24]

PS Power plans to begin construction on 267 MW of combustion turbine capacity at Kearny in the second quarter of 2011. The estimated cost of the project is $250 to $300 million. The project is expected to be in service by June 2012.[25] PS Power plans to retire three units at Kearny totaling 271 MW in 2012 and 2013.[26]

PS Power Fuel Mix

Nuclear plants account for approximately 60 percent of PS Power's PJM generation. PS Power's 2008 and 2009 PJM net generation is shown below by plant.

[24] PJM web-site, Planning, Generation Retirements, Generation Retirement Summaries, Generator Deactivations.
[25] PSEG Third Quarter 2010 SEC 10-Q Report, page 29.
[26] PJM web-site, Planning, Generation Retirements, Generation Retirement Summaries, Pending Deactivation Requests.

Table 16-8 - PS Power Plants in PJM Net Generation by Plant 2008 and 2009

PS Power Plants in PJM Net Generation by Plant 2008 and 2009 - Gigawatt Hours		
Plant	2008	2009
Salem	9,997	11,200
Hope Creek	9,992	9,700
Peach Bottom	9,267	9,405
Bergen	5,327	4,947
Linden	3,964	4,119
Keystone	3,231	2,408
Conemaugh	2,582	2,735
Hudson	2,197	1,416
Mercer	2,164	1,426
Essex	253	97
Kearny	145	77
Burlington	137	72
Edison	120	43
Sewaren	70	30
Yards Creek	-137	-101
Total	49,309	47,574
Source: US Department of Energy, Energy Information Agency, Form EIA-923 databases for 2009 and 2008. Salem, Peach Bottom, Keystone, Conemaugh and Yards Creek adjusted to reflect PSEG ownership percentage.		

The following table shows PS Power's PJM net generation by fuel type in 2009 and 2010.

Table 16-9 - PS Power Net Generation in PJM Percentage by Type of Fuel 2009 and 2010

PS Power Net Generation In PJM Percentage By Type of Fuel 2009 and 2010		
Fuel Type	2009	2010
Nuclear	64	58
Coal	16	19
Gas and Oil	20	23
Total	100	100
Source: PSEG web-site, PSEG 2010 Earnings Announcement, February 22, 2011, Attachment 8.		

PS Power Financial Results

PS Power was highly profitable during our review period. The following table shows the returns on equity reported by PS Power for 2007 through 2010.

Table 16-10 - PS Power Return on Equity 2007 to 2010

PS Power Return on Equity 2007 to 2010 Dollars in Millions				
Description	2007	2008	2009	2010
Net Income	992	1,115	1,189	1,143
Average Member's Equity	3,659	3,937	4,395	4,747
Return on Equity	27.1	28.3	27.1	24.1
Source: PSEG 2009 10-K, pages 89 and 91 and 2010 10-K pages 94 and 96.				

PS Power's member equity represented 59 percent of its consolidated capital structure as of December 2009.[27] PS Power's high equity returns are not the result of a highly leveraged capital structure.

Long-standing transmission constraints result in higher energy prices in the eastern mid-Atlantic (EMAAC) and southwestern mid-Atlantic (SWMAAC) regions than in western PJM. The constraints limit the ability to import lower cost coal generation into EMAAC and SWMAAC from western PJM.

EMAAC consists of the PSE&G, Atlantic City Electric, Delmarva Electric, Jersey Central, Peco Energy and Rockland Electric transmission zones. SWMAAC consists of the Baltimore Gas & Electric and Potomac Electric Power Company transmission zones.[28]

The energy price for PSE&G's zone was fifteen percent higher than the PJM average in 2010, as shown on the following table.

[27] PSEG 2009 SEC 10-K Report, page 90.
[28] 2009 PJM State of the Market Report, Appendix A.

Table 16-11 - PJM and PSE&G Zone Average Energy Prices Day-Ahead Load Weighted Average 2006-2010

PJM and PSE&G Zone Average Energy Prices Day-Ahead Load Weighted Average 2006 to 2010 - Dollars Per MWH			
Year	Total PJM	PSE&G Zone	Ratio
2006	51	58	1.13
2007	58	68	1.17
2008	70	86	1.22
2009	39	44	1.13
2010	48	55	1.15

Source: Volume 2 of the PJM State of the Markets Reports for 2007 (pages 67 and 69); 2009 (pages 78 and 80) and 2010 (page 84) . Ratio is PSEG price divided by PJM average price.

PS Power's competitive advantages include having a low-cost generating fleet with many units located near large load centers east of PJM transmission constraints.[29] All of PSEG's PJM generating capacity is located in EMAAC, except for the Conemaugh and Keystone plants.

PS Power uses a hedging strategy that incorporates full requirement load contracts, such as the BGS, and other contracts to secure pricing over a two to three year forward time horizon. PS Power describes the BGS as the foundation of its hedging strategy. According to PS Power, its balanced generation portfolio is "in ideal position to serve BGS."[30]

PSEG's 2009 10-K Report includes the following description of PS Power's competitive environment.[31]

- Various market participants compete with us...in buying and selling in wholesale power pools, entering into bilateral contracts and selling to aggregated retail customers....

- New additions of lower cost or more efficient generation capacity could make our plants less economical in the future. Although it is not clear if this capacity will be built or, if so, what the economic impact will be, such additions could impact market prices and our competitiveness.

- Our business is also under competitive pressure due to demand side management (DSM) and other efficiency efforts aimed at changing the quantify and patterns of usage by consumers which could result in a reduction in load requirements. A reduction in load requirements could also be caused by economic factors and cycles.

[29] PSEG web-site, Investor Presentations, 2010 EEI Financial Conference, November 1-2, 2010, page 10.
[30] PSEG web-site, Investor Presentations, Barclays Capital 2010 CEO Energy/Power Conference, September 16, 2010, page 24.
[31] PSEG 2009 SEC 10-K Report, page 15.

- 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 transmission.

- To the extent that additions to the transmission system relieve or reduce congestion in eastern PJM where most of our plants are located, our revenues could be adversely affected. Changes in the rules governing transmission planning or cost allocation could also impact our revenues.

- We are also at risk if one or more states in which we operate should decide to turn away from competition and allow regulated utilities to own or reacquire and operate generating stations in a regulated and potentially uneconomic manner, or to encourage rate-based construction of new generating units...

PSE&G faces minimal risks from competitors. PSE&G's transmission and distribution business is minimally impacted when customers choose alternative suppliers.[32]

Market Power

PSEG owns approximately one-third of the generating capacity in EMAAC and ninety percent of the generating capacity in the PSEG transmission zone.

Table 16-12 - PSEG Generation Capacity Ownership Share as of December 2009

PSEG Generation Capacity Ownership Share As of December 2009			
Area	Total Capacity MW	PSEG Owned MW	PSEG Percentage
Total PJM	179,090	11,793	7
EMAAC	33,479	11,017	33
PSEG	8,037	7,210	90
PSEG North	4,652	3,563	90
Source: PJM website, RPM Auction User Information, 2013/14 Delivery Year, RPM Resource Model, 2/1/10, adjusted to eliminate post 2009 retirements.			

Market power is the ability of a market participant to increase or decrease the market price above or below the competitive level. Market power is a serious concern in PJM energy and capacity markets.

The highest average annual market share in PJM's energy market was 22 percent in 2009. The highest hourly market share was 32 percent.[33]

[32] PSEG 2009 SEC 10-K Report, page 16.
[33] PJM 2009 State of the Market Report, Volume 2, page 22.

The PJM energy markets are moderately concentrated overall. The baseload segment of the supply curve is moderately concentrated. The intermediate and peaking segments are highly concentrated.[34] When transmission constraints exist, local markets are created that are significantly more concentrated that the overall PJM energy market. High concentration levels in the peaking segment increase the probability that a generation owner will have market power during high demand periods.

The PJM State of the Market Report includes the following description of the RPM capacity market.[35]

> *The Capacity Market is, by design, always tight in the sense that total supply is generally only slightly larger than demand. The demand for capacity includes expected peak load plus a reserve margin. Thus, the reliability goal is to have total supply that is equal to or slightly above, the demand for capacity. The market may be long at times, but that is not the equilibrium state. Capacity in excess of demand is not sold and, if it does not earn adequate revenues in other markets, will retire. Demand is almost entirely inelastic because market rules require load to purchase their share of the system capacity requirement. The result is any supplier that owns more capacity than the difference between total supply and defined demand is pivotal and has market power.*
>
> *In other words, the market design for capacity leads, almost unavoidably, to structural market power. Given the basic features of the market structure in the PJM Capacity Market, including significant market structure issues, inelastic demand, tight supply-demand conditions, the relatively small number of unaffiliated LSEs (Load Serving Entities) and supplier knowledge of aggregate market demand, the MMU concludes that the potential for the exercise of market power continues to be high. Market Power is and will remain endemic to the existing structure of the PJM Capacity Market.*
>
> *This is not surprising in that the Capacity Market is the result of an regulatory/ administrative decision to require a specified level of reliability and the related decision to require all load serving entities to purchase a share of the capacity required to provide that reliability...The Capacity Market is unlikely ever to approach the economist's view of a competitive market structure in the absence of substantial and unlikely structural change that results in much more diversity of ownership.*

PSEG owns 90 percent of the capacity located within its transmission zone. The highest capacity market share in EMAAC is 33 percent.[36] PJM did not disclose the identity of the generation owner with the highest market share in EMAAC. However, as previously noted, PS Power owns 33 percent of the generating capacity in EMAAC.

[34] PJM 2009 State of the Market Report, Volume 2, page 21.
[35] PJM 2009 State of the Market Report, Volume 2, page 309.
[36] PJM MMU, Analysis of the 2013/2014 RPM Base Residual Auction, September 5, 2010, page 5.

PJM's tariffs require the PJM Independent Market Monitor (IMM) to apply preliminary market power screens prior to every RPM base residual auctions. The capacity market has consistently failed all of those screens on both an RTO and local delivery areas (LDA) basis.

Market Power Mitigation - Energy Markets

PJM's market power mitigation rules are critical to protecting consumers from market power abuse. PJM has four basic safeguards that limit the exercise of market power in the energy market.

- Capacity that clears in RPM capacity auctions is required to bid in the day-ahead energy market whenever the unit is available. Excessive outages reduce the generating unit's RPM capacity revenues. That discourages withholding of energy.
- PJM caps energy bids made by pivotal suppliers when transmission constraints cannot be resolved without accepting bids made by those suppliers.
- PJM has a market monitoring program to identify the exercise of market power. The monitoring program is implemented by the PJM IMM.
- All energy market prices are capped at $1,000 per MWH.

The test for applying the energy price caps is called the Three Pivotal Supplier Test (TPST). According to PJM:[37]

> *The three pivotal supplier test measures the degree to which the supply from three generation suppliers is required in order to meet the demand to relieve a constraint. Two key variables in the analysis are the demand and the supply. The demand consists of the incremental effective MW required to relieve the constraint. The supply consists of the incremental effective MW of supply available to relieve the constraint....For purposes of the test, incremental MW are attributed to specific suppliers on the basis of their control of the assets in question...*
>
> *The supply directly included...in the three pivotal supplier test consists of the incremental effective MW of supply that are available at a price less than, or equal to, 1.5 times the clearing price that would result from the intersection of demand (constraint relief required) and the incremental supply available to resolve the constraint....*

Three suppliers are pivotal if incremental generation from them is required to relieve a local constraint or load pocket. When three or less suppliers are pivotal, price caps are applied to the units included in the pivotal suppliers' effective incremental supply for the constraint. The TPST is an automated process implemented by PJM's system dispatch software.

[37] PJM 2009 State of the Market Report, Volume 2, page 588.

For most units that fail the TPRS, the offer cap is set at incremental operating cost plus 10 percent.[38] Frequently Mitigated Units are allowed to include higher adders in their price caps as a form of local scarcity pricing.[39] PSE&G does not know if any of PS Power's units are Frequently Mitigated Units.[40]

The TPRS was implemented in 2005. TPRS offer caps rarely apply. The following table shows the unit hours capped in 2008 and 2009.

Table 16-13 - PJM Energy Market Unit Hours Price Capped Three Pivotal Supplier Test

PJM Energy Market Unit Hours Price Capped Three Pivotal Supplier Test Percentage of Total Hours		
Market	2008	2009
Real-Time	1	0.4
Day Ahead	0.2	0.1
Source: PJM 2009 State of the Market Report, Volume II, page 25.		

The PJM IMM calculates the mark-up included in the bids submitted by the marginal units that set energy prices. According to the IMM, the markup metric demonstrates PJM energy prices generally reflect the incremental operating costs of the marginal unit.[41] The IMM concluded the mark-up results were strong evidence that the energy markets were competitive in 2009 and prior years.

The incremental operating costs used to calculate IMM's markup metric equal cost plus a 10 percent adder. The adder accounts for the imprecision in the estimating process.[42]

The average dollar markup becomes larger as energy market prices increase. When the prices were between $100 and $125 per MWH, the average marginal unit markup in the real-time energy market was $12.10 in 2010, not counting the 10 percent adder.[43] If the 10 percent adder is treated as additional markup, the energy bids during those hours were 23 percent higher than marginal cost. [44]

[38] FERC Initial Order on Market Power Mitigation Provisions, Docket EL08-47-000, February 19, 2009, page 4.
[39] PJM 2009 State of the Market Report, Volume 2, page 26.
[40] Response to Discovery, OC-1200.
[41] PJM 2009 State of the Market Report, Volume 1, page 16.
[42] Testimony of Joseph Bowring, PJM Market Monitor, March 30, 2007, Maryland Public Service Commission Case No. 9099, page 5.
[43] PJM 2009 State of the Market Report, Volume 2, page 44.
[44] The Average energy price of $112.50 minus $12.10 = $100.40. That amount divided by 1.1 indicates marginal cost without adder of $91.27. Total markup is $112.50 minus $91.27 = $21.23. That amount is 23 percent of $91.27.

Market Power Mitigation - Capacity Market

All existing generating units are subject to cost-based bid caps in the RPM capacity auction. The following capacity resources are not subject to offer caps.[45]

- Planned new generating units;
- Demand Response;
- Energy Efficiency.

The offer caps for existing generation reflect the unit's avoidable costs, net of projected margins from PJM energy and ancillary services markets.[46] Avoidable costs are the costs that the unit would not incur if it did not operate in the RPM delivery year.

The existing generation resources have the following four options:

- Submit a generation bid of zero and participate in the RPM auction as a price taker;
- Select the default offer cap established by PJM for the applicable generation technology;
- Submit unit specific avoidable cost information to the PJM IMM and use a unit-specific offer cap; or
- Submit opportunity costs for a verified opportunity to sell the output of the unit outside PJM. If the RPM clearing price is lower than the export offer, the unit's capacity does not clear in the RPM and is available for export.

The following table shows the existing generation resources participating in the most recent RPM base residual auction by offer cap type.

Table 16-14 - May 2010 RPM Base Residual Auction for 2013/2014 Delivery Year

May 2010 RPM Base Residual Auction For 2013/2014 Delivery Year Existing Generation Offer Caps by Type	
Type	Generating Units
Price Taker	450
Default Cap	580
Unit Specific Cap	107
Opportunity Cost	13
Total	1150
Source: IMM Analysis of 2013/2014 RPM BRA, September 20, 2010, page 4	

[45] Analysis of the 2013/2014 RPM Base Residual Auction, PJM Independent Market Monitor, September 20, 2010, page 2 .

[46] PJM Open Access Transmission Tariff, Attachment DD, Section 6.4.

The default and unit-specific caps reflect estimated avoidable costs plus a 10 percent adder.[47]

The unit-specific offer caps include avoidable capital expenditures that are required to maintain the unit as a capacity resource. The portion of the offer cap attributable to capital expenditures is referred to as the Avoidable Project Investment Recovery Rate (APIR). Generators are allowed to recognize the capital expenditures on a levelized basis, with a 10 percent adder, over one to 30 years, depending on the plant's age. Plants over 40 years old are allowed to recognize all of the capital expenditures in the delivery year.[48]

In the most recent RPM base residual auction, 92 of the 107 unit-specific caps included an AIPR. The AIPR significantly increased the price caps for those units. The following table shows the weighted average AIPR and offer caps for the units with an AIPR.

Table 16-15 - May 2010 RPM Base Residual Auction for Delivery Year 2013/2014

May 2010 RPM Base Residual Auction For Delivery Year 2013/2014 APIR Statistics - Weighted Average Dollars per MW Day		
Technology	AIPR	Offer Cap
Combustion Turbine	25	41
Combined Cycle	No Units	No Units
Oil or Gas Steam	243	278
Coal	352	112
Source: Analysis of the 2013/2014 RPM Base Residual Auction, PJM IMM, September 20, 2010, page 13.		

The offer cap for coal is lower than the AIPR because the energy revenue offset exceeds the other avoided cost elements for those plants.

The default offer caps are much lower than the unit-specific offer caps that include an AIPR. The following table shows the weighted average offer caps for units without an AIPR component, including units that selected the default value.

[47] PJM Open Access Transmission Tariff, Attachment DD, Section 6.8.
[48] PJM Open Access Transmission Tariff, Attachment DD, Section 6.8.

Table 16-16 - May 2010 RPM Base Residual Auction for Delivery Year 2013/2014

May 2010 RPM Base Residual Auction For Delivery Year 2013/2014 Offer Caps For Units Without AIPR Weighted Average - Dollars per MW Day	
Technology	Offer Cap
Combustion Turbine	16
Combined Cycle	7
Oil or Gas Steam	68
Coal	9
Source: Analysis of the 2013/2014 RPM Base Residual Auction, PJM IMM, September 20, 2010, page 13.	

According to the PJM IMM "Reliance on the RPM design for competitive outcomes means reliance on the market power mitigation rules. Attenuation of those rules would mean that market participants would not be able to rely on the competitiveness of market outcomes."[49]

Market Power Mitigation - Monitoring Program

The mission of the IMM is to ensure that PJM's market structure and participant conduct:[50]

- Facilitate competition;
- Limit returns to market power;
- Provide incentives to competitive behavior;
- Make the exercise of market power more difficult; and
- Stop the exercise of market power before significant impact.

The IMM monitors:[51]

- Compliance with PJM market rules;
- Actual or potential design flaws in the market rules;
- Structural problems in PJM market that may inhibit a robust and competitive market;
- The potential for a market participant to exercise market power or violate market rules;
- The actual exercise of market power or violation of market rules; and
- PJM's implementation of market rules.

[49] Analysis of the 2013/2014 RPM Base Residual Auction, PJM IMM, September 20, 2010, page 1.
[50] PJM web-site, Training, Market Monitoring in PJM, GEN 301, page 3.
[51] Monitoring Analytics web-site, Reports, Role of the Market Monitoring Unit, Market Monitoring Advisory Committee, December 2, 2010.

The IMM actively participates in the PJM committee process and intervenes in FERC proceedings addressing PJM market rules. The IMM prepares a voluminous annual State of the Market Report and quarterly State of the Market Reports.

The IMM receives and reviews assertions of market power and gaming from PJM, regulators and market participants. If sufficient credible information indicates a violation has occurred, the IMM refers the matter to the FERC.[52]

The IMM budget for 2010 was $10.1 million. As of September 2009, the IMM had 20 full time employees and 7 full time contractors.[53]

According to the IMM, market rules are critical to ensuring competitive market performance because PJM's markets are characterized by structural market power.[54]

BGS Power Supply

BGS-FP is a full requirements product that includes load following and transmission. The following chart shows PSE&G's BGS-FP prices by auction.

Table 16-17 - PSE&G BGS-FP Auction Prices 2005 to 2010 Auctions

PSE&G BGS-FP Auction Prices 2005 to 2010 Auctions	
Auction Date February	Price per MWH
2005	65
2006	103
2007	99
2008	112
2009	104
2010	96
2011	94
Source: BGS auction website.	

BGS-FP prices peaked in 2008. The 2011 price is 16 percent lower than the 2008 price. The factors impacting BGS-FP prices are discussed in Chapter 13.

PS Power is an active participant in the New Jersey BGS auctions, as shown on the following table.

[52] Monitoring Analytics web-site, Reports, Role of the Market Monitoring Unit, Market Monitoring Advisory Committee, December 2, 2010.

[53] PJM web site, PJM Finance Committee, September 24, 2009 meeting Monitoring Analytics Preliminary budget for 2010.

[54] PJM web site, PJM Finance Committee, September 24, 2009 meeting Monitoring Analytics Preliminary budget for 2010.

Table 16-18 - BGS-FP Tranches Awarded to PS Power (ER&T)

BGS-FP Tranches Awarded to PS Power (ER&T)					
Zone	2011	2010	2009	2008	2007
PSE&G	13	11	10	13	13
JCP&L	4	5	7	3	6
ACE	3	3	3	0	0
RECO	0	0	0	1	0
Total PS Power Tranches	20	19	20	17	19
State Total	53	54	54	50	51
Percent PS Power (ER&T)	38	35	37	34	37
Source: BGS-auction.com					

Each tranche represents approximately 100 MW of peak demand. PS Power currently serves approximately 5,600 MW of BGS-FP load statewide.[55]

New Jersey BGS-FP sales accounted for approximately 40 percent of PS Power's PJM generation in 2009.[56]

The following table shows the number of tranches awarded in PSE&G's seven most recent BGS-FP auctions.

Table 16-19 - PSE&G BGS-FP Tranches Awarded to PS Power (ER&T)

PSE&G BGS-FP Tranches Awarded to PS Power (ER&T)			
Auction Date February	ER&T	Total	Percent ER&T
2005	8	28	29
2006	12	29	41
2007	13	28	46
2008	13	28	46
2009	10	29	34
2010	11	28	39
2011	13	28	46
Source: BGS-auction.com			

[55] Total of 2008, 2009 and 2010 tranches times 100 MW.
[56] Overland analysis based on PSE&G BGS-FP load factor.

PSE&G's BGS-FP energy purchases are shown below for 2007, 2008 and 2009.

Table 16-20 - PSE&G Percentage of BGS-FP Load Supplied by PS Power (ER&T)

PSE&G Percentage of BGS-FP Load Supplied by PS Power (ER&T) 2007 - 2009				
Year	ER&T GWH	Other Suppliers	Total GWH	Percent ER&T
2007	13,118	21,923	35,041	37
2008	14,287	19,356	33,643	42
2009	12,708	16,612	29,320	43
Source: Response to Discovery, OC-165 and OC-946				

BGS Auction Process

PSE&G passes its BGS power costs on to ratepayers, while PS Power's profits are retained by shareholders, creating an inherent incentive for PSE&G to provide an unfair preference to PS Power in the BGS procurement process.

The following features of the BGS procurement process protect ratepayers against the risk of affiliate abuse.[57]

- Competitive bidding;
- Independent process management;
- Standard product definition;
- Equal access to information for all bidders;
- Price-only bid evaluation criteria;
- BPU oversight.

The BGS procurement process is closely supervised by the BPU. The BPU reviews and approves the auction process and results. The bidder qualification and auction processes are administered by the Independent Auction Manager (IAM). The BPU retains a Board Advisor to monitor and oversee the auction process.

The IAM serves as the single point of contact for providing information to bidders. The IAM responds to all questions from bidders. The questions and responses are posted on the auction web-site providing equal access to information for all bidders.

[57] Robinson Interview, March 3, 2010 and Joint EDC Proposal For BGS Service Requirements, BPU Docket No. ER10040287, July 2, 2010.

The product is defined by the BGS Supplier Master Agreement (Master Agreement). The BPU reviews and approves the terms of the Master Agreement. All winning bidders must comply with the terms of the Master Agreement.

Once a bidder is qualified, the only bid evaluation criteria is price. The standardized contract terms, standardized qualification process, equal access to information and price-only basis for evaluating bids provide transparency to the process.

The auction rules include statewide and utility specific "load caps" that limit the number of tranches that a bidder can win. The statewide BGS-FP load cap was 37 percent of load in the February 2010 auction.[58] The PSEG BGS-FP load cap was 13 tranches.[59]

According to PSE&G's Director of BGS/BGSS Services:[60]

- PSE&G does not provide any information to PS Power that is not provided to all of the other BGS bidders;
- PS Power does not have any input into the formulation of PSE&G's regulatory proposals concerning the BGS;
- The IAM, the Board Advisor and the other bidders have not raised any issues related to PS Power's participation in the auctions;
- The BPU and the parties to the BPU's BGS proceedings have not raised any issues related to PS Power's participation;
- PSE&G has not granted any waivers of the BGS Master Supplier Agreement to PS Power.

PSEG issues BGS Rules of Engagement (BGS rules) each year.[61] The BGS rules indicate "It is in the overall best interests of Enterprise and all of its subsidiaries that the BGS supply is determined through a process that achieves meaningful competition and produces a result that reflects market-based supply for BGS service."

The BGS rules indicate:[62]

- Interactions between PSE&G and PS Power shall be conducted in a manner that assures that PS Power does not receive any preference or advantage in the auction over a third party bidder.
- PSE&G shall respond to all questions from PS Power concerning the BGS in the same manner as questions posed by non-affiliates.

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[58] BPU Decision and Order, Docket No. EO09050351, December 10, 2009, page 11. That equates to approximately 20 tranches.
[59] BGS web-site, Auction Results for February 2010 auction.
[60] Robinson interview, March 3, 2010.
[61] Response to Discovery, OC-1421.
[62] Response to Discovery, OC-1421.

- PSE&G and PS Power will be represented by separate legal counsel.
- PSE&G will not suggest any bidding strategies to PS Power.
- Designated holding company (PSEG) officers and employees may confer freely with PSE&G and PS Power about all aspects of the BGS auction and bidding. The designated individuals are prohibited from transferring information received from PSE&G to PS Power concerning the following subjects: (1) bidding strategies; (2) pricing; (3) specific elements of auction design; (4) other matters that might reasonably be anticipated to materially affect the outcome of the auction; and (5) information contrary to BPU rules. The designated individuals are also prohibited from transferring the same types of information from PS Power to PSE&G.
- The PSE&G employees involved with the auction will be physically separated from PS Power employees during the auction.
- Meetings involving PSE&G and PS Power senior management are generally permitted. Any discussions of the BGS auction during those meetings must be limited to information that is the public domain.

The BGS-FP auction process includes several valuable safeguards that protect ratepayers against possible affiliate abuse.

PS Power owns 33 percent of all of the generating capacity in EMAAC and 90 percent of the generating capacity in PSEG's zone. The number of tranches awarded to PS Power is consistently close to the overall state and PSE&G load caps. That implies that PS Power has a significant cost advantage compared to other bidders. The magnitude and persistence of PS Power's BGS market share raise concerns about the competitiveness of the underlying market.

Independent Transmission Control

LSEs purchase transmission services under PJM's Open Access Transmission Tariff (OATT). Generation and transmission owners do not purchase transmission services unless they are also LSEs. The BGS suppliers and third party retail (TPR) suppliers are the LSEs for PSE&G's distribution customers.

PJM administers the OATT. The BGS and TPR suppliers make their transmission arrangements with PJM, not PSE&G.[63] PJM provides the required transmission and ancillary services and processes requests for interconnections. PJM makes all decisions for scheduling services and processing interconnection requests.[64] PJM transfers the revenues received from transmission customers to PSE&G as a credit on PSE&G's monthly PJM bills.[65]

The BGS and TPR suppliers purchase most of their required transmission services under the network integration tariff for PSE&G's transmission zone. Network integration service accounted for 98 percent of

[63] PJM web-site, Markets & Operations, Transmission Services page.
[64] PSEG web-site, PSE&G Oasis - Electric Transmission Information page, PSE&G written procedures, Standards of Conduct Compliance Procedures, Final Version 6/3/10.
[65] Response to Discovery, OC-178.

PSE&G's transmission revenues in 2009.[66] The network integration rates allocate PSE&G's transmission revenue requirement to firm transmission customers based on peak demand.

PJM controls the operation of the bulk electric system (BES) within its region. The BES is defined as facilities rated 100kV and higher.[67] PSE&G transmission data is telemetered to the PJM control room on a real time basis. The PJM control room has the full authority and responsibility for maintaining BES reliability.

PSE&G monitors and controls the PSE&G BES under the direction of PJM and is responsible for local reliability functions and support activities.[68] PSE&G operates the system in accordance with PJM operating procedures and instructions from the PJM control room. All actions taken by PSE&G impacting BES facilities must be approved by PJM unless emergency conditions make pre-approval impractical.[69]

PJM operates the energy, capacity and ancillary services markets. PJM schedules generation and power transactions and dispatches generation in real time to balance the energy supply and demand on the system. PSE&G does not perform any generation scheduling, control or dispatch functions.[70]

PSE&G is responsible for transmission system maintenance in accordance with good utility practice and PJM policies and procedures.[71] PSE&G schedules maintenance outages on its transmission system subject to PJM approval.

PJM is responsible for administering the interconnection process for new generation entrants, including:

- processing interconnection requests;
- administering the interconnection request queues;
- system impact and feasibility studies.

PSE&G participates in scoping and feasability study meetings and may propose reasonable alternatives to the planned interconnection.[72] The transmission owner is a party to the resulting interconnection agreements and provides interconnection services during construction and operation of the generation facility. Interconnection services are discussed in Chapter 17.

PJM is responsible for transmission system planning within its region. The planning can be divided into two areas - reliability and economic expansion. Reliability planning is completed first and focuses on identifying violations of reliability standards and proposing solutions. PJM identifies potential violations, and PSE&G recommends proposed solutions subject to PJM's approval. Economic planning looks at

[66] Response to Discovery, OC-178 and OC-1079.
[67] PJM Manual 3: Transmission Operations, page 14.
[68] Response to Discovery, OC-503.
[69] PJM Manual 3: Transmission Operations, page 16.
[70] Response to Discovery, OC-503.
[71] PJM Manual 3: Transmission Operations, page 16.
[72] PJM Open Access Transmission Tariff, Sections 36.1.5 and 36.2.

projects that lower overall system costs. PJM takes the lead in economic planning. The economic planning process was implemented in 2007 and has only resulted in a small number of transmission projects to date.[73]

PSE&G provides data and analysis to PJM in the transmission planning process, including facility ratings, substation loads and system impedance. Transmission owners are required to follow PJM standards and guidelines when developing facility ratings. PJM audits the capacity rating methodologies used by transmission owners.

PJM's control over transmission tariff administration, operations and planning substantially reduces the risk that transmission owners could provide generation affiliates with an unfair advantage over competitors.

Affiliate Relations Rules

Regulated electric utilities have a monopoly on electric distribution and transmission services within their service territories. Regulated utilities generally charge cost-based rates for those services. Most of the economic consequences of the distribution and transmission operations accrue to ratepayers. In contrast, the economic consequences of non-regulated operations accrue to shareholders. The joint ownership of regulated public utilities and non-regulated businesses creates an incentive to subordinate the economic interests of the regulated utility and ratepayers to those of the non-regulated affiliates, and shareholders.

The reality of the incentive, the subtlety with which it can work, and the clear conscience with which a manager can often respond to it all argue for regulatory oversight of affiliate relations.[74]

The need for affiliate relations rules does not depend on malevolent management intent. Given the profit seeking motive, management is naturally inclined to favor those defensible arrangements that transfer the greatest amount of benefits from the utility to competitive affiliates. Those influences would only be eliminated by a genuinely arms-length relationship which does not exist. Regulatory oversight is a necessary substitute for the incentives normally provided by an arms-length relationship.

Public utility affiliate relations rules have a long history in the United States. The landmark Public Utility Holding Company Act of 1935 (PUHCA) created extensive affiliate relations rules for multi-state electric utility holding companies. Regulators have recognized the need to police the interface between regulated and non-regulated activities for more than 70 years.[75]

[73] Khadr interview, October 9, 2010.
[74] New York Public Service Commission Opinion No. 93-11, Case 87-C-8959, July 6, 1993, (Rochester Telephone Corporation).
[75] PUCHA was repealed in 2005. One of the basic rationales for repealing PUHCA was that state regulators have the authority and capability to protect ratepayers from affiliate abuse.

Affiliate relations rules typically include the following:

- Financial "ring-fencing" requirements;
- Operational separation requirements;
- Restrictions on information transfers;
- Restrictions on joint negotiations, including purchasing and marketing;
- Transfer pricing rules for affiliate transactions; and
- Record keeping and reporting requirements.

Financial ring-fencing requirements are implemented to protect the utility's access to capital on reasonable terms. Ring-fencing requirements are discussed in Chapter 10. Operational separation requirements and information transfer restrictions are implemented to:

- Reduce opportunities for affiliate interests to influence utility actions to the detriment of ratepayers;
- Reduce opportunities for the cross-subsidization of the competitive affiliate through preferential access to ratepayer funded resources; and
- Protect consumers and competitors against unfair competitive practices.

Restrictions on joint negotiations are implemented to reduce opportunities for cross-subsidization through package deals.[76] Transfer pricing rules are implemented to prevent cross-subsidization through preferential access to ratepayer funded resources. Regulatory reporting and record keeping requirements are implemented to identify abusive practices and allow oversight of rules compliance.

The BPU and FERC have several affiliate relations rules for electric utilities. Those rules are listed below.

- BPU Affiliate Relations Rules;[77]
- BPU Holding Company Rules;[78]
- FERC Standards of Conduct For Transmission Providers;[79]
- FERC Affiliate Restrictions;[80]
- FERC Cross-Subsidization Restrictions;[81] and

[76] Package deals exchange terms that are unfavorable to the utility for terms that are favorable for a non-regulated affiliate. For example, the utility agreeing to purchase goods at an above market prices in exchange for the supplier providing goods to a non-regulated affiliate at below market prices. Or, a utility's agreement to purchase goods from a vendor could be conditioned on the vendors agreement to drop a legal claim against a non-regulated affiliate.

[77] N.J.A.C. 14:4-3.

[78] N.J.A.C. 14:4-4. The formation of PSEG as a holding company was approved by the BPU in 1986. The approval order includes conditions requiring the holding company to: (1) provide access to its consolidated tax return; (2) maintain separate utility books and records; (3) maintain support for cost allocations; and (4) provide access to relevant affiliate books and records. The 1986 conditions also prohibit pledging utility assets as security for affiliate debt. The 1986 conditions are largely superceded by the BPU's Holding Company Rules. Order Authorizing Transfer of Capital Stock and Approval of Merger, BPU Docket EM8507774, January 17, 1986.

[79] 18 CFR 358.2.

[80] 18 CFR 35.39.

[81] 18 CFR 35.44.

- FERC Holding Company Rules.[82]

The FERC Holding Company rules address access to books and records and service company cost allocations.

BPU Affiliate Relations Rules

The BPU Affiliate Relations Rules set forth standards of conduct for relations between a public utility and "competitive business segments" of the utility and affiliates that offer competitive services to retail customers in New Jersey.[83]

PS Power does not offer competitive services to retail customers in New Jersey. According to PSE&G, the BPU's Affiliate Relations Rules to not apply to PS Power or its subsidiaries, including ER&T.[84] PSE&G only applies the BPU Affiliate Rules to the following groups.

Table 16-21 - BPU Affiliate Relations Rules, PSE&G Competitive Business Segments Number of Employees

BPU Affiliate Relations Rules PSE&G Competitive Business Segments Number of Employees	
Name	Employees
PSE&G Appliance Service Business	912
PSEG Demand Management Company	2
PSEG Solar Source LLC and PSEG Solar Hackettstown LLC	5
Total	919
Source: Response to Discovery, OC-718	

The BPU Affiliate Rules include provisions that:

- prohibit the utility from providing non-regulated businesses with preferential access to utility resources, services and information; and
- require structural separation between the utility and non-regulated business operations.

PSE&G does not apply those rules to PS Power or its subsidiaries.

BPU Holding Company Rules

The BPU adopted Holding Company Rules in March 2009.[85] Many of the rules focus on financial ring-fencing. The financial rules are discussed in Chapter 10.

[82] 18 CFR 366.1.
[83] N.J.A.C. 14-4-3.1.
[84] Response to Discovery, OC-750, page 25.
[85] Response to Discovery, OC-362, page 70.

The rules relevant to power supply:

- Require PSEG to notify the BPU if any federal or state government agency instigates an investigation or audit of PSEG or any of its subsidiaries.[86]
- Require BPU approval for any service agreements between PSE&G and affiliates.[87]
- Prohibit PSE&G from purchasing any product or service from affiliates that PSE&G can obtain "on more advantageous terms" by other means.[88] Other means include self-supply and purchasing the product or service from non-affiliates.
- Require PSE&G to review its purchases from affiliates every three years for compliance with the most advantageous terms requirement.[89]

The initial "most advantageous terms" compliance review is required by April 2012.

FERC Standards Of Conduct For Transmission Providers

The FERC's Standards of Conduct for Transmission Providers (FERC Transmission Standards) require the utility's "transmission function employees" to operate independently from the "marketing function employees" of affiliates. The FERC Transmission Standards also prohibit the transfer of transmission function information to affiliate marketing function employees on a preferential basis.[90]

The definitions of transmission function and marketing function employees are fairly narrow. Transmission function employees are engaged in "planning, directing and organizing or carrying out day-to-day transmission operations, including the granting or denying of transmission services." Marketing function employees "actively and personally engage on a day-to-day basis" in the sale or purchase of power, demand response or transmission rights. The FERC emphasized the limiting nature of the qualifier "day-to-day operations" in the order adopting the current standards.[91]

PSE&G has 38 transmission function employees as shown on the following table. PSEG reviews the list of transmission function and marketing function employees on a monthly basis to track for departures, new hires, employee transfers and changes in job scope.

[86] N.J.A.C. 14:4-4.A.4(c)
[87] N.J.A.C. 14:4-4.A.5(a).
[88] N.J.A.C 14:4-4.A.5(g).
[89] N.J.A.C 14:4-4.A.5(h).
[90] 18 CFR, Part 358.
[91] FERC Order 717, Docket RM07-01-001, October 16, 2008.

Table 16-22 - FERC Standards of Conduct for Transmission Providers, PSE&G Transmission Function Employees

FERC Standards of Conduct For Transmission Providers PSE&G Transmission Function Employees	
Department	Headcount
VP Electric Operations	1
System Operations	25
VP Asset Management & Centralized Services	1
Electric Delivery Planning	10
Asset Reliability	1
Total	38
Response to Discovery, OC-752	

The Systems Operations employees work in PSE&G's transmission control room. The Electric Delivery Planning employees are responsible for distribution and transmission system planning. The definition of transmission function employees does not include PJM and FERC regulatory policy. PSE&G's Director of Transmission Business Strategy is not a transmission function employee.

PS Power has the following marketing function employees.

Table 16-23 - FERC Standards of Conduct for Transmission Providers PS Power Marketing Function Employees

FERC Standards of Conduct For Transmission Providers PS Power Marketing Function Employees	
Department	Headcount
VP Power Trading and Operations	1
Energy Operations	29
Trading	12
Marketing and Origination	2
Energy Generation Desk	1
Marketing New England	1
Total	45
Response to Discovery, OC-752	

All of PS Power's marketing function employees are located with ER&T.[92] Transmission function employees and marketing function employees must operate and function independently and separately from each other. The FERC Transmission Standards do not require the separation of any other employee groups.

[92] In addition, certain PSEG Global employees and a few PSE&G employees are marketing function employees.

Under the FERC Transmission Standards, all employees that are neither marketing function employees or transmission function employees may be shared by the utility and its affiliates.[93]

The FERC Transmission Standards define transmission function information as information related to "planning, directing, organizing or carrying out day-to-day transmission operations." Under the FERC standards, transmission function information may not be provided to marketing function employees.

The FERC standards do not limit the information that PSE&G can provide to most PS Power employees. According to PSE&G, utility employees can transfer non-public transmission information to PS Power employees, as long as the PS Power employees are not market-function employees.[94]

According to PSE&G: [95]

- PSE&G transmission rate design employees are not transmission function employees so long as they are not personally and actively involved in day-to-day transmission system operations.
- PSE&G Transmission Planning Group employees are not transmission function employees, as they are not personally and actively involved in day to day operations of the transmission system or planning as it relates to real-time operations (e.g. transmission outage planning).[96]
- Long-range transmission planning is not a transmission function activity under the FERC Standards.
- ER&T Market Development Group employees are not marketing function employees because their responsibilities are strategic rather than operational in nature.
- The FERC's focus on "active and personal" engagement makes it less likely that officers, directors or supervisors will be classified as transmission function employees or marketing function employees.

The scope of the FERC Transmission Standards is very limited in terms of the employee groups and information covered. The FERC Transmission Standards provide only limited protections for PSE&G ratepayers.

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[93] FERC Order On Request for Clarification, Docket No. RM04-7-007, April 15, 2010, page 17.
[94] Response to Discovery, OC-1267, page 9.
[95] Response to Discovery, OC-1267, page 25.
[96] PSE&G's training materials, provided in Response to Discovery, OC-1267, indicate transmission planning employees are not transmission function employees. Electric Delivery Planning is PSE&G's primary transmission planning group. Response to Discovery, OC-752 indicates PSE&G classifies the employees in that group as transmission function employees.

FERC Affiliate Restrictions

The FERC Affiliate Restrictions are imposed as a condition of obtaining market-based rate authority for merchant power affiliates.[97] The Affiliate Restrictions are intended to ensure separation of functions and restrict the sharing of market information between public utilities and their market-regulated affiliates.[98]

The Affiliate Restrictions are summarized below.

- All wholesale power transactions between the utility and the market- regulated affiliate require prior authorization from the FERC.
- To the maximum extent practical, the employees of the market-regulated affiliate must operate separately from utility employees.
- The utility and market-based affiliate are allowed to share support employees, field and maintenance employees, senior officers and boards of directors.
- The utility may not share non-public market information with market-regulated affiliates if the sharing could be used to the detriment of captive customers.
- The transfer price for sales of non-power goods and services from the utility to market-regulated affiliates will be the higher of cost or market.
- The transfer price for sales of non-power goods and services from the market-regulated affiliate to the utility may not be above market.

The definition of market information is shown below.[99]

> *Market information means non-public information related to the electric energy and power business including, but not limited to, information regarding sales, cost of production, generator outages, generator heat rates, unconsumated transactions, or historical generator volumes. Market information includes information from either affiliates or non-affiliates.*

PSE&G's training materials for FERC Affiliate Restriction compliance are very concise. The are reproduced below in their entirety.[100]

- employees of a utility (e.g. PSE&G) are prohibited from sharing market information regarding itself or any third-party entity with a market regulated power sales affiliate - i.e. an affiliate having market-based rate authority (e.g. ER&T, PSEG Fossil and PSEG Nuclear).
    - Market information is any non-public information concerning electric generation, including information regarding cost of production, generator outages, and historical generation data.

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[97] 18 CFR 35.39.

[98] FERC Order On Request for Clarification, Docket No. RM04-7-007, April 15, 2010, page 17. FERC uses the term "market-regulated affiliate" to refer to merchant generation affiliates with market-based rate authority.

[99] 18 CFR 35.36(a)(8).

[100] Response to Discovery, OC-750, page 12.

- employees of a utility are required to operate separately from the employees of any market-regulated power sales affiliate, to the maximum extent practical, but
  - field and maintenance employees and senior officers may be shared.
  - employees of a utility may interact with employees of a market-regulated power sales affiliate in emergency circumstances affecting system reliability.

The FERC Affiliate Restrictions prohibit PSE&G from providing market information to PS Power. According to PSE&G, the restrictions do not prohibit PS Power from providing market information to PSE&G.[101]

The FERC Affiliate Restrictions provide substantially more protection to ratepayers than the FERC Transmission Standards of Conduct because the Affiliate Restrictions apply to much larger employee groups. The Affiliate Restrictions require operational separation between the utility and affiliates. The FERC Transmission Standards only require separation of transmission and marketing function employees.

The FERC Affiliate Restrictions only apply to utilities that have captive customers. The FERC determined that default supply customers are not captive customers because they have the option of selecting a TPR supplier.[102]

In its October 2008 Order renewing ER&T's market-based rate authorization, the FERC ordered PSE&G and ER&T to comply with the Affiliate Restrictions because PSE&G failed to demonstrate it did not have any captive wholesale customers.[103] PSE&G requested a waiver of the Affiliate Restrictions in July 2010 on the basis that PSE&G does not have any captive retail or wholesale customers.[104]

On February 25, 2011, the FERC concluded that PSE&G does not have captive customers and authorized waiver of the independent function and information disclosure prohibitions contained in its Affiliate Restrictions (at 18 CFR 35.39).[105]

In addition to seeking a waiver, PSE&G advocates substantially weakening the FERC Affiliate Restrictions. According to PSE&G, the Affiliate Rules should be modified to allow utilities and affiliates to share any employees who are not "transmission function" and "marketing function" employees under the FERC Transmission Standards.[106] Under that proposal, the same individual could manage a utility's default supply power solicitation and prepare the bid submitted by a merchant generation affiliate. The FERC rejected that position in April 2010.[107]

[101] Response to Discovery, OC-362, page 11, Restricted.
[102] FERC Order No. 697, Docket No. RM04-7-000, June 21, 2007, page 271.
[103] FERC Order in Docket No. ER97-837-007, dated October 17, 2008, page 17.
[104] Response to Discovery, OC-962.
[105] Order on Affiliate Restrictions, PSEG, 134 FERC Par. 61,138 (Feb. 25, 2011)
[106] Amended Request for Clarification of the Compliance Working Group, Docket No. RM04-7-007, October 28, 2009.
[107] FERC Order on Request for Clarification, Docket No. RM04-7-007, April 15, 2010.

FERC Cross-Subsidization Rules

The FERC Cross-Subsidization Rules focus on transfer pricing for non-power goods and services and apply to transactions between utilities and their non-utility affiliates.[108]

The FERC Cross-Subsidization Rules are summarized below.[109]

- Utility sales of non- power goods and services to affiliates shall be priced at the higher of cost or market.
- Affiliate sales of non-power goods and services to the utility cannot be priced above market.
- The services provided to utilities by centralized service companies shall be priced at cost.

The cross-subsidization rules do not require structural separation between utility and affiliate operations and do not restrict the transfer of utility information to affiliates.

PSE&G Compliance Policy

PSE&G's policy is to comply with FERC and BPU affiliate rules and regulations. PSEG's Standards of Integrity indicate all employees are expected to understand and comply with BPU and FERC affiliate rules and regulations.[110]

The Standards of Integrity indicate the following affiliate standards have particular significance. [111]

- PSE&G transmission function employees (as defined) must function independently of affiliate marketing function employees.
- Preferential treatment is not provided to any seller of electricity, gas or energy services, whether or not the seller is an affiliate.
- Transmission function employees must not disclose transmission function information (as defined) to marketing function employees.
- PSE&G customer information cannot be provided to any third party without the customer's written consent, unless the disclosure is required by law.
- PSE&G must not disclose non-public information regarding its distribution operations to affiliates that provide retail competitive services in New Jersey.
- Leads, tying preferences, joint marketing, joint procurement or other similar activities that provide a competitive advantage are not engaged in for the benefit of competitive affiliates.
- Costs are appropriately charged or allocated between PSE&G and affiliates.

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[108] PSE&G's training materials define non-power goods as all goods other than electricity or gas. Non-power services are defined as all services that are not regulated by FERC. Response to Discovery, OC-750 page 13.

[109] Response to Discovery, OC-1267, page 33.

[110] PJM web-site, Standards of Integrity, page 30.

[111] PSEG Standards of Integrity, pages 30 and 31.

The Standards of Integrity do not address the operational separation and information sharing requirements of the FERC Affiliate Restrictions, which applied during the audit period.

The BPU Affiliate Rules do not apply to PSE&G's interactions with PS Power. The FERC Transmission Standards only apply to a small percentage of PSE&G and PS Power employees. The FERC Cross-Subsidization Rules only apply to transfer pricing. The FERC Affiliate Restrictions are the only rules that currently require most PSE&G employees to operate independently from PS Power employees.

The FERC Transmission Standards prohibit the direct or indirect transfer of a narrowly defined set of transmission function information to a small group of employees within ER&T. The information transfer restrictions in the FERC Affiliate Restrictions cover all PSE&G employees but only apply to a narrowly defined set of market information. The FERC Affiliate Restrictions and the BGS auction confidentiality requirements are the only restrictions on the non-customer specific utility information that PSE&G can provide to the vast majority of PS Power employees.

PSE&G believes it was in compliance with the FERC Affiliate Restrictions during the audit period.[112] However, the information provided by PSE&G to support that claim is largely irrelevant to the FERC Affiliate Restrictions. The information provided by PSE&G addresses FERC Transmission Standards and BPU Affiliate Rules compliance, and does not demonstrate compliance with the FERC Affiliate Restrictions.

Operational Separation

Operational separation is a key regulatory safeguard for managing the incentives created by joint ownership of regulated and non-regulated operations. PSE&G's affiliate rules compliance procedures are inadequate because they do not ensure operational separation between PSE&G and PS Power.

PSE&G and PS Power share the same headquarters building in downtown Newark. PS Power employees are located on different floors than PSE&G employees, with a few minor exceptions.

The PSE&G and PS Power groups responsible for power supply and power marketing functions are all located in the headquarters building.[113] The following table shows the PSE&G groups.

[112] Response to Discovery, OC-964 and OC-965.

[113] PS Power's power supply marketing and energy trading functions are all performed by ER&T. Response to Discovery, OC-195.

Table 16-24 - PSE&G Groups with Power Supply Management Functions

PSE&G Groups with Power Supply Management Functions	
Group	Floor
Corporate Rate Counsel (BGS proceedings)	8
Energy Acquisition (BGS/BGSS and NUG)	8
Renewables and Energy Solutions	8
Retail Settlement (Load Settlement and BGS Supplier Credit Analysis)	18
Environmental Health & Safety (Renewable energy certificates)	17
Regulatory Counsel (BGS proceedings)	5
Corporate Commercial Counsel (BGS and NUG contracts)	19
Risk Management (BGS credit analysis)	22
Transmission Business Strategy (PJM market design and interconnection planning)	13
Electric Delivery Planning (Transmission Planning)	Note 1
Note 1: Electric Delivery Planning is located on floors 12, 13 or 14.	
Source: Response to Discovery, OC-194, OC-946, Robinson interview, March 3, 2010 and OC-983.	

PSE&G's transmission engineering and construction functions are located on the Floors 12, 13 and 14 of the headquarters building and at PSE&G's Hadley Road facility.[114]

All of PS Power's power supply management functions are located on the 19th floor of the headquarters building.[115]

PSE&G has a key card system to restrict access to its Electric System Operations Center (ESOC) and headquarters building floors.[116] Overland reviewed the access lists for the Energy Acquisition Group work area, PSE&G's Hadley Road facility and the 12th, 13th, 14th and 18th floors of the headquarters building. The access lists did not include any PS Power employees.[117]

Recommendation: PSE&G and PS Power should develop compliance plans for ensuring utility and PS Power personnel operate independently to the maximum extent practical.

PSE&G has a written compliance plan for ensuring physical separation between transmission function and marketing function employees.[118] PSE&G does not have any other plans or written procedures for ensuring the operational separation of PSE&G and PS Power employees.[119]

Operational separation is a key regulatory safeguard. PSE&G should develop a plan and procedures for ensuring the operational separation of all utility and PS Power employees.

[114] Response to Discovery, OC-197 and OC-953.
[115] Response to Discovery, OC-194.
[116] Response to Discovery, OC-1085.
[117] Response to Discovery, OC-763 and OC-976.
[118] Response to Discovery, OC-67 and OC-197.
[119] Response to Discovery, OC-67, OC-197 and OC-964.

PS Power does not have any compliance plans or written procedures for ensuring that its employees operate separately from utility employees.[120] PS Power should develop a plan and procedures for ensuring separation.

Recommendation: PSE&G should track meetings jointly attended by utility and PS Power personnel.

PSE&G tracked a broad range of "cross-functional" meetings jointly attended by utility and PS Power personnel prior to 2009. PSE&G stopped tracking most of those meetings in late 2008, when the FERC Transmission Standards changed to a functional approach.[121]

PSE&G's current policy, which complies with FERC regulations, is to only track meetings jointly attended by transmission function and marketing function employees. Marketing function employees must leave the room when PSE&G transmission function information, as defined by the FERC Transmission Standards, is discussed.[122] PSE&G's procedures require meeting documentation consisting of an agenda and list of attendees.

The only joint meetings tracked in 2009 were six RTO issues meetings and nine Federal Regulatory Policy Team (FRPT) meetings.[123] Those meetings focus on PJM market design issues and related FERC proceedings.

Tracking and documenting joint meetings is essential to assessing whether PSE&G employees operate independently from PS Power. Effective regulatory oversight of the following risks depends on tracking and documenting PSE&G meetings with PS Power.

- Modification of utility policies and actions to advance affiliate interests;
- preferential access to utility resources; and
- Package deals.

PSE&G should track and document all meetings attended jointly by utility and PS Power employees. The documentation should include the meeting agenda, list of attendees and meeting notes. The meeting documentation should be forwarded to PSE&G's compliance counsel and made available to the BPU Staff upon request.

[120] Response to Discovery, OC-69.

[121] Response to Discovery, OC-755.

[122] PSEG web-site, PSE&G Oasis - Electric Transmission Information page, PSE&G written procedures, Standards of Conduct Compliance Procedures, Final Version 6/3/10, page 6.

[123] Response to Discovery, OC-755, OC-513 and OC-514.

Information Sharing Restrictions

Recommendation: PSE&G should develop compliance plan to limit PS Power's access to non-public utility information.

PSE&G's has written procedures prohibiting PS Power marketing function employees from accessing PSE&G transmission information, as defined by the FERC Transmission Standards.[124] PSE&G's training materials include two sentences prohibiting PSE&G from providing PS Power with market information, as defined in the FERC Affiliate Relations Rules.[125] PSEG's Standards of Integrity prohibit the release of customer-specific utility information to PS Power without the customer's consent.

PSE&G does not have any other affiliate relations procedures for restricting the release of non-public utility information to PS Power.[126]

PSEG's corporate-wide Information Security Practices restrict access to information systems and databases to authorized users through the use of user accounts, passwords and access profiles.[127] All authorization requests require authorization from the system owner prior to granting access.[128] The criteria for granting access is not stated in PSE&G's affiliate procedures.

PSE&G's affiliate procedures should explicitly prohibit PS Power employees from accessing utility information systems and databases. PS Power employees should also be prohibited from accessing the utility components of PS Service Corporation systems, including PSEG's enterprise accounting system (SAP). PSE&G should track and report all authorizations that allow PS Power employees to access utility systems or databases.

The PSEG Supply Chain Management (SCM) Procurement Practices Manual illustrates the need to clarify information access restrictions. Section 5.6 addresses compliance with FERC and BPU affiliate relations rules.[129] The manual indicates "SAP security control practices segregate access to procurement related information in accordance with" the FERC Transmission Standards and SCM associates are responsible for ensuring compliance with the FERC Transmission Standards.

The procurement practices do not directly prohibit allowing PS Power employees to access utility purchasing files. The procurement practices could be read to permit:

[124] PSEG web-site, PSE&G Oasis - Electric Transmission Information page, PSE&G written procedures, Standards of Conduct Compliance Procedures, Final Version 6/3/10.
[125] Response to Discovery, OC-750, page 12.
[126] Response to Discovery, OC-67, OC-197 and OC-69.
[127] Access profiles restrict a users access to data within the system and the activities that the user can perform.
[128] Response to Discovery, OC-80, 2009 BPU Affiliate Rules Compliance Plan, page 79.
[129] Response to Discovery, OC-857.

- PS Power employees who are not "marketing function employees" to access all of PSE&G's procurement files; and
- PS Power employees who are marketing function employees to access all procurement files that do not contain "transmission function information."

PSE&G's procurement files include solicitations, specifications, bid evaluations and other information. Permitting PS Power access to that information does not serve any legitimate business purpose, increases the risk of package deals and might provide PS Power with a competitive advantage over other generating companies. PSE&G's procurement practices should clearly prohibit PS Power from accessing utility procurement files and prohibit SCM associates from disclosing utility procurement information PS Power. If access is provided, it should be tracked and reported.

PSE&G should prohibit the transfer of non-public utility information to PS Power. PS Power employees should be prohibited from accessing utility information systems, data bases and other files. Sharing should only be allowed when it is authorized in writing by the PSE&G officer who "owns" the data and is approved by PSE&G's compliance council.[130] The approval documentation should state the business purpose and regulatory authority for sharing the data with PS Power.

Recommendation: PSE&G should track non-public utility information provided to PS Power.

PSE&G does not have a process for approving and tracking the sharing of utility information with PS Power. PSE&G does not see the need to track information exchanges that are not prohibited by the BPU or FERC rules. Because prohibited information is not transferred to PS Power, there is nothing to track. According to PSE&G:[131]

> *There [are] only two types of information that should not be shared - PSE&G confidential information, assuming such information exists vis-a-vie PS Power...[and] non-public transmission information. PSE&G is prohibited from sharing that information with only a subset of employees in ER&T. Absent these contacts, PSE&G is not prohibited from sharing information with PS Power affiliates. There is nothing to be tracked.*

According to PSE&G, it provided very little non-public utility information to PS Power during 2008 and 2009. At the executive level, earnings forecasts are reviewed monthly. Information is also shared through periodic RTO issues meetings and FRPT meetings.[132]

PSE&G's data responses on information sharing did not identify the transfers of non-public utility information associated with the following:

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[130] The information transfer should be approved by the PSE&G Officer who directs the PSE&G organization that is the designated internal owner of the information.

[131] Response to Discovery, OC-1414.

[132] Response to Discovery, OC-506 and OC-508.

- BGSS Full Requirements Contract with ER&T;
- PSEG Capital Review Committee;
- EMS Memorandum of Understanding;
- PSE&G Study Work Agreement with PS Power;
- The equipment testing and other services provided to PSE&G by PS Power's Maplewood testing lab; and
- PSE&G Agreement for Scheduling NUG Resources with ER&T.

The omissions raise concerns that additional information transfers have not been identified.

The presidents of PSE&G and PS Power participate jointly in the PSEG capital review committee (CRC). The CRC reviews PSE&G and PS Power five year capital plans and all construction projects exceeding $10 million. The capital review committee receives periodic updates on the status of major PSE&G and PS Power construction projects.[133] The CRC met eleven times in 2009. The materials reviewed by the CRC in 2009 included:

- Project Funding Requests for new construction projects describing project scope, costs and benefits;
- Five year capital expenditure forecasts for each project;
- Periodic status updates on the Susquehanna-Roseland Transmission Line and the Branchburg-Roseland-Hudson Transmission Line;
- Susquehanna - Roseland Transmission Line project risk analyses and mitigation strategies; and .
- Presentations on PSE&G's Solar-4-All, energy efficiency and demand response programs.

The joint participation of PSE&G and PS Power in the CRC creates two risks:

- PSE&G capital projects could be influenced by PS Power interests to the detriment of ratepayers; or
- PS Power could gain a competitive advantage from having inside knowledge of PSE&G construction plans.

PSE&G prepared a transmission impact study for PS Power in 2009 under a Study Work Agreement.[134] The study was prepared outside of the normal PJM interconnection study process. The study identified transmission network upgrades that would be required by the construction of a new nuclear unit adjacent to the Hope Creek and Salem plants. The results of the study were provided to PS Power in a transmission impact study report. The report is non-public utility information.[135]

[133] Response to Discovery, OC-267 and OC-1245.
[134] Response to Discovery, OC-502 and OC-711.
[135] The Study Work Agreement is discussed in Chapter 17.

PS Power's Maplewood Testing Service (MTS) is commonly referred to as the Maplewood Testing Lab. PSE&G transferred MTS to the PSEG Services Corporation as part of electric industry restructuring. MTS was transferred to PS Power effective January 1, 2009.[136] PSE&G purchases testing services from MTS. The scope of the testing services includes all of the electrical equipment in PSE&G's distribution and transmission systems. MTS has specifications and lifetime testing data for that equipment. The testing data is non-public utility information.[137]

Tracking the exchange of non-public information between PS Power and PSE&G is necessary for effective regulatory oversight. Tracking significantly increases the efficiency and effectiveness of regulatory audits by reducing the time required to identify transfers and increasing the number of identified transfers. Auditors cannot assess the appropriateness of transfers that are never identified. PSE&G should implement a process for tracking and approving transfers of non-public utility information to PS Power.

The reporting requirement should apply broadly to all non-public utility information transferred to PS Power. Reporting requirements that are limited to defined categories of information are not enforceable because of the difficulty of constructing, interpreting, communicating and applying the defined categories.

Energy Management System

PSE&G's Energy Management System (EMS) is its electric system control and data acquisition (SCADA) system. The EMS system collects real-time transmission and generation data from 129 remote terminal units (RTUs) and transmits the data to PSE&G's ESOC. Twenty-nine of the RTUs are located at PS Power plants. PS Power owns 103 of 144 generating units tracked by EMS.[138] The system operators in the ESOC use the data to monitor and physically operate PSE&G's transmission system.[139]

PSE&G provides ER&T with access to the utility Energy Management System under a Memorandum of Understanding, dated August 2007.[140] ER&T's access is provided through two workstations located in its offices on the 19th floor. ER&T's access is limited to: [141]

- Data for generating units owned by PS Power; and
- PJM system data that is available to all generators through PJM, including system demand, area control error and Lambda.[142]

ER&T uses the data to calculate its energy market bidding strategy.[143]

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[136] Response to discovery, OC-1481.
[137] The testing services that MTS provides to PSE&G are discussed in Chapter 17.
[138] Response to Discovery, OC-748.
[139] Response to Discovery, OC-503.
[140] Response to Discovery, OC-502.
[141] Interview with Robert Green, PSE&G Manager System Reliability, March 3, 2010. Mr. Green signed the Memorandum of Understanding on behalf of PSE&G.
[142] Lambda is the cost to the PJM system of the next unit of output. LMP reflects Lambda.
[143] Green Interivew

Non-affiliated generation owners do not have access to the EMS. The large non-affiliated plants located in PSE&G's electric service territory are the Eagle Point, Newark Bay, Camden and Bayonne co-generation plants.[144] The EMS includes RTUs at those plants. PSE&G sends the data collected from those plants to PJM. The non-affiliated generators can access the data through PJM, without the screens and functionality added by the EMS system.[145]

The non-affiliated generators do not operate large portfolios of plants. As a result, they do not need as much data as ER&T to formulate their bidding strategies. ER&T could obtain generation data from PJM, but using EMS is easier and provides screens and functionality not available from PJM.[146]

Recommendation: PSE&G should document the basis for the EMS cost allocation factor.

PSE&G replaced its EMS with a new system in December 2008. The replacement project cost was $2.7 million.[147] ER&T paid 18.75 percent of the replacement cost and pays the same percentage of ongoing EMS operations and maintenance costs.

ER&T had similar access to the old EMS system. PSE&G did not charge ER&T for access to the old system for many years. PSE&G began charging ER&T for EMS access when the Memorandum of Understanding was implemented in August 2007.[148]

In 2009, ER&T paid $764,910 in EMS charges.[149] The EMS includes RTUs for PS Power generating plants located outside of PSE&G's service territory. ER&T pays 100 percent of the costs associated with those RTUs.[150]

The ER&T cost allocation factor of 18.75 percent is based on engineering judgment. The basis for the factor is poorly documented. The documentation supports an allocation of 40 percent of EMS costs to ER&T.[151] That implies the charges to ER&T were approximately $867,000 lower than they should have been in 2009.[152]

Basing affiliate charges on engineering judgment is problematic because of the incentives created by joint ownership of cost-regulated and non-regulated businesses. PSE&G should review the EMS cost allocation factor and prepare a memorandum that fully explains the basis for the factor.

Under the FERC Cross-Subsidization Rules, PSE&G should charge ER&T the higher of cost or market for the EMS services. PSE&G has not estimated the market value of the services. PSE&G should prepare an

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[144] The Newark Bay, Camden and Bayonne plants are owned by the Morris Energy Group.
[145] Green interview.
[146] Green interview.
[147] Response to Discovery, OC-746.
[148] Response to Discovery, OC-502 and Green interview.
[149] Response to Discovery, OC-747.
[150] Response to Discovery, OC-502.
[151] Response to Discovery, OC-748.
[152] $764,910 divided by 0.1875 indicates total costs of $4,079,520 x 0.40 equals $1,631,808 minus $764,910 equals $866,898.

estimate of the market value of the EMS services provided to ER&T and prepare a memorandum that fully explains the basis for the estimate. The estimate should include an assessment of the value of the data to ER&T and the costs ER&T would incur to replace EMS functionality.

BGSS Requirements Contract

The 1999 Electric Discount and Energy Competition Act deregulated gas supply in New Jersey. Gas distribution customers who do not select a third party retail supplier receive default service under PSE&G's Basic Gas Supply Service (BGSS) tariff.[153]

PSE&G transferred all of its gas supply contracts to ER&T in 2002, including its pipeline transportation and storage contracts.[154] ER&T provides PSE&G's BGSS gas supply under the BGSS Full Requirements Contract. The BGSS Requirements Contract was effective May 1, 2002 and was originally scheduled to expire in March 2004. The contract was extended and currently expires in March 2012.

ER&T is responsible for delivering all of the gas required to serve BGSS customers to PSE&G's gas distribution system. Residential customers account for 73 percent of BGSS firm requirements. Residential BGSS costs are approximately $1.0 billion per year.[155]

PSE&G states that its residential BGSS rates are typically the lowest or second lowest among New Jersey's gas utilities.[156]

ER&T's charges to PSE&G are based on ER&T's actual cost of providing the gas supply services.[157] ER&T acquires gas commodities through a mix of supplies that are priced on both the daily and monthly markets. ER&T also obtains supplies for residential customers that are hedged at a fixed price for price stability.[158]

ER&T has a large portfolio of pipeline transportation and storage contracts. ER&T has 12 employees that spend all of their time on BGSS activities. Those employees are shown below by function.

[153] PSE&G Gas Service Tariff Sheet No. 54.
[154] Response to Discovery, OC-481.
[155] PSE&G 2010/2011 Annual BGSS Commodity Charge filing, Testimony of David Caffery, Items 6 and 7, July 14, 2010.
[156] Response to Discovery, OC-549.
[157] Response to Discovery, OC-482, Requirements Contract, Section 2.2.
[158] Response to Discovery, OC-224.

Table 16-25 - ER&T BGSS Gas Supply Employees By Function

ER&T BGSS Gas Supply Employees - By Function	
Function	Headcount
Supply Acquisition	3
Capacity Acquisition	1
Regulatory	2
Scheduling	3
Planning	2
Management	1
Total	12
Source: Response to Discovery, OC-1419	

If surplus pipeline capacity is available, ER&T makes off-system wholesale sales and shares the resulting margins with BGSS customers. If pipeline capacity remains after satisfying BGSS requirements and off-system sales opportunities, ER&T uses the surplus capacity to provide "generation gas" to PS Power's New Jersey generating stations.[159]

The prices ER&T charges to PS Power are determined under two alternative methods, depending on the circumstances. If the incremental generation gas supplies are not substantially more expensive than what otherwise would have been purchased, they are priced at the weighted average cost of the total gas supply portfolio. If the total delivered cost of the incremental generation gas is substantially higher than the portfolio average, ER&T charges the total delivered cost of the incremental supply to PS Power.[160]

The following table shows the generation gas volumes for 2008 and 2009 by pricing method.

Table 16-26 - BGSS Requirement Contract, Generation Gas Sold to PS Power by Pricing Method

BGSS Requirements Contract Generation Gas Sold to PS Power by Pricing Method 2008 and 2009 Millions of Dth		
Pricing Method	2008	2009
Weighted Average Method	64	52
Incremental Method	23	26
Total	87	78
Source: Response to Discovery, OC-532		

[159] Response to Discovery, OC-532.
[160] Response to Discovery, OC-532.

The BGSS annual firm volumes are approximately 190 million Dth. As such, the generation gas volumes are significant in comparison to the BGSS firm volumes.[161]

Had FERC not determined that the FERC Affiliate Restrictions were inapplicable to PSEG, the utility would be prohibited from sharing fuel procurement employees with merchant generation affiliates.[162] FERC prohibited the sharing of fuel procurement employees for utilities with captive wholesale or retail customers because they would have an incentive to assign lower priced fuels to the merchant affiliate and higher priced fuels to the cost-regulated utility.[163] Irrespective of FERC's Order, the joint management of PSE&G's default gas supply and PS Power's fuel supply functions creates the risk that BGSS ratepayers will be required to subsidize PS Power's fuel costs.

Most of PS Power's net generation is nuclear and coal-fired. Higher gas prices benefit PS Power because they increase the margins earned by most of PS Power's generating stations. Providing PS Power with control over PSE&G's BGSS gas supply portfolio increases the risk of influencing delivered gas costs in New Jersey. Outsourcing BGSS gas supply management to an entity that has a profit motive to increase delivered gas costs is problematic.

Recommendation: PSE&G should review the advantages and disadvantages of outsourcing BGSS Gas procurement to ER&T.

PSE&G has not reviewed the costs and benefits of outsourcing BGSS gas procurement to ER&T since the initial BPU proceeding in 2002.[164] PSE&G has not estimated the market value of the services provided by ER&T.[165]

PSE&G has not prepared any studies of the costs incurred by ER&T to provide services under the contract. PSE&G estimates ER&T incurs approximately $8 million a year of internal costs to provide the services.[166]

The BPU's Holding Company rules require PSE&G to review the BGSS Contract by March 2012 to determine if PSE&G could:

- perform the BGSS gas supply function internally at a lower cost; or
- procure the services from an independent supplier on more advantageous terms.

The BGSS Requirements Contract is a sole source procurement and was not obtained through a competitive process. Based on the potential issues identified above, the joint management of utility and merchant generation gas procurement is a questionable business practice.

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[161] The generation gas volumes are equivalent to about 40 percent of the BGSS firm volumes. PSE&G 2010/2011 Annual BGSS Commodity Charge filing, Testimony of David Caffery, Item 6, July 14, 2010.
[162] FERC Order Denying Rehearing, Docket No. RM04-7-009, January 20, 2011.
[163] FERC Order on Request for Clarification, Docket No. RM04-07-007, April 15, 2010, page 20.
[164] Response to Discovery, OC-1416.
[165] Response to Discovery, OC-1417.
[166] Response to Discovery, OC-1418.

The BGSS Requirements Contract has been in place for about nine years. PSE&G has not demonstrated that the contract is the lowest cost method of procuring BGSS gas supply. The BGSS Requirements Contract also has adverse market power implications. It is time for a substantive review of the advantages and disadvantages of outsourcing PSE&G's BGSS gas supply function to ER&T.

PSE&G should prepare a study of the advantageous and disadvantages of the current approach compared to the alternatives of: (1) performing the gas supply function internally; and (2) purchasing the services from a non-affiliated vendor. The study should estimate the costs and benefits of each alternative and identify the lowest-cost alternative for BGSS gas supply.

PSE&G should review the default gas supply procurement practices of other large gas distribution utilities and identify industry best practices. PSE&G should identify other gas distribution utilities that outsource gas supply management and compare their outsourcing arrangements to the BGSS Requirements Contract. PSE&G should review options for implementing a competitive procurement that would allow non-affiliates to compete with ER&T for the business.

PSE&G's study should assess the cross-subsidization and market power risks created by joint management of utility and merchant affiliate gas supply and describe PSE&G's plan and controls for mitigating those risks.

The study should assess ER&T's incentives for reducing delivered gas costs after considering the impacts on its generation profits. The study should assess whether controlling the BGSS gas supply portfolio provides PS Power with the ability to increase the margins earned by its nuclear and coal-fired generating units.

Gas Transportation Services

PSE&G provides gas transportation services to the PS Power plants located in its gas distribution service territory. PS Power purchases gas from non-affiliated suppliers and arranges for delivery of the gas to PSE&G's distribution system. PSE&G transports the gas over its distribution system and delivers the gas to PS Power's generating stations.

The gas transportation service is provided on an interruptible basis. PSE&G provides the service at a large discount from its tariff rates for non-firm gas transportation service.[167] The gas transportation margins received from PS Power reduce PSE&G's BGSS gas supply rates. PSE&G discloses its charges to PS Power in its annual BGSS reconciliation charge filing. The BPU has consistently approved the resulting BGSS rates.[168]

[167] PSEG Rate Schedule TSG-NF, Tariff Sheet 99.

[168] Direct Testimony of Frederick Lark, BPU Docket No. GR09050422, August 13, 2010, page 4.

PSE&G provides gas transportation services to four generating stations owned by the Morris Energy Group (MEG). MEG filed testimony in PSE&G's 2010 gas base rate case alleging that:[169]

- The discounts PSE&G provides to PS Power were not justified by a verifiable by-pass threat; and
- PSE&G discriminates in favor of PS Power by charging lower gas transportation rates than it charges to similarly situated non-affiliated generators.

PSE&G does not require PS Power to comply with the terms and conditions of its gas transportation rate schedules. The services are provided without a written agreement between PS Power and PSE&G. MEG alleged that PSE&G discriminates in favor of PS Power by not requiring PS Power to comply with its standard terms and conditions of service.[170]

The service provided to PS Power is interruptible. However, the terms of interruption are not documented in writing. PSE&G's tariff gas transportation terms and conditions include substantial charges for balancing services.[171] PSE&G does not charge PS Power for balancing services.[172]

In response to MEG's allegations, the BPU extended the gas base rate proceeding and initiated a separate generic proceeding to examine its policies concerning rate discounts for customers with verifiable by-pass options.[173]

PSE&G submitted testimony in the extended proceeding concerning PS Power's by-pass options and costs. According to PSE&G, the rate discounts had been reviewed and approved by the BPU and are fully justified by PS Power's by-pass options.[174]

The BPU approved a settlement in the extended proceeding in December 2010. The settlement:[175]

- Reduced the gas transportation rates charged to MEG plants; and
- Froze the rates charged to PS Power pending the completion of the generic proceeding.

These issues have been resolved in the context of the BPU generic gas proceeding that concluded with an August 18, 2011 Board Order defining the conditions under which discounted gas delivery agreements would be available.[176]

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[169] Response to Discovery, OC-852, Direct Testimony of John Reed on behalf of Morris Energy Group, page 14.
[170] Response to Discovery, OC-852, Direct Testimony of John Reed on behalf of Morris Energy Group, page 6.
[171] Balancing refers to the difference between the quantity of gas the customer delivers to PSE&G's distribution system and the amount of gas that the customer withdraws from PSE&G's distribution system during a time period.
[172] Electric Customer Group (MEG) Comments, BPU Docket Nos. GR10100761 and ER10100762, January 28, 2011, page 17.
[173] Decision and Order Adopting Initial Decision with Modifications, BPU Docket No. GR09050422, July 9, 2010, page 23.
[174] Testimony of John Morris and Testimony of Anthony Furhman, BPU Docket No. GR09050422, August 13, 2010.
[175] Decision and Order Adopting the Stipulation of Settlement, BPU Docket No. GR09050422, December 22, 2010.
[176] BPU Docket Nos. GR10100761 and ER10100763.

PSE&G provided substantial gas transportation services to PS Power for over a decade without written service terms and conditions.[177] PSE&G provided the services at a large discount from tariff rates without documenting the basis for the discount. Gas transportation discounts must be justified by a credible by-pass threat. PSE&G did not require PS Power to demonstrate its by-pass options and costs.

PSE&G provides interruptible service to PS Power. The interruption terms are not documented in writing. PSE&G also provides balancing services to PS Power without written terms or charges. Utilities can subsidize affiliate profits by not enforcing contract terms. Regulatory oversight is the key safeguard for managing that risk. Auditing the enforcement of contract terms and remedying non-compliance is difficult when the terms are not documented.

Joint Participation in PJM and FERC Matters

PSEG directs and controls the management of its subsidiaries, including PSE&G. PSEG's policy is to take one unified corporate position at FERC.[178] The unified corporate position is developed by PSEG's Vice President-Regulatory located within the PSEG Services Corporation Law Department. PSE&G and PS Power provide input into the development of the unified positions.[179] The purpose of the unified positions is to advance PSEG's business interests.[180]

The interests of generators and consumers do not always coincide. Generators seek higher profits for generation, while consumers seek lower prices and reliable service.

PSEG's business interests are heavily weighted towards merchant generation. PS Power accounts for approximately 75 percent of PSEG's net income. Increases in power prices directly increase PS Power's profits. PS Power's profits are increased by:

- Discouraging the construction of new power plants by competitors;
- Discouraging the construction of transmission enhancements that lower energy prices;
- Promoting market rule changes that increase capacity and energy prices; and
- Discouraging competition from demand response providers.

PJM Voting Patterns and FERC Positions

PJM is governed by an independent Board of Managers. The Board is appointed by the Members Committee. The Members Committee advises the Board by voting on proposed changes to PJM's market

[177] PSE&G transferred most of the generating stations to PS Power in 2000.
[178] OC-190, OC-191 and OC-878, page 17.
[179] Response to Discovery, OC-878 and Napoli interview.
[180] Response to Discovery, OC-878, pages 5 and 6.

rules and operating procedures. The Members Committee oversees a hierarchy of committees and working groups that address policy and operational issues.[181]

The Members Committee and the Markets and Reliability Committee (MRC) are the two senior committees in the PJM structure. The MRC reports to the Members Committee.

PJM has over 500 members. PSE&G and ER&T are both members of PJM. Only one member of a corporate family is allowed to vote on the Members Committee and the MRC. A holding company with multiple generation and utility affiliates can only cast one vote on those committees.[182]

PJM uses a sector voting system on the Members Committee and the MRC. The fives sectors are:

- Transmission Owners
- Generation Owners
- End User Customers
- Electric Distributors
- Other Suppliers.

PSEG votes in the Transmission Owners sector.[183] The End User sector includes industrial customers and state consumer agencies. The Electric Distributers are municipal utilities and rural electric cooperatives. The Other Suppliers are largely energy traders.

Under the sector voting system, each sector has one vote. The sector's vote is allocated into "for" and "against" components based on the voting within the sector. If 60 percent of the sector votes for a proposal, the sector's vote is 0.60 for and 0.40 against. A super-majority of 3.33 out of the total possible 5.00 votes is required to pass a proposal.[184]

PJM publishes voting reports for the Members Committee. Overland reviewed the 25 voting reports published for meetings held in 2008, 2009 and 2010. The following table shows the percentage of time that PSE&G voted with the majority of each sector.

[181] PJM web-site, Governance Page.

[182] An Assessment of PJM's Governance and Stakeholder Process, Raab Associates, September 17, 2009, page 14. The report was commissioned by PJM and is available on the PJM web-site.

[183] Most investor-owned utilities elect to participate in the Transmission Owners sector.

[184] An Assessment of PJM's Governance and Stakeholder Process, Raab Associates, September 17, 2009, page 30.

Table 16-27 - PJM Voting Results Percentage PSE&G Voted with Each Sector

PJM Voting Results Percentage PSE&G voted with Each Sector 2008 to 2010	
Sector	Percentage
Transmission Owners	96
Generation Owners	88
End User Customers	28
Electric Distributors	32
Other Suppliers	60
Source: PJM web-site, Members Committee Page, Meeting Materials, Voting Reports.	

PSE&G voted with the majority of the Transmission Owners in 24 out of 25 votes. The Transmission Owners and Generation Owners usually vote the same way. The Transmission Owners voted with the Generation Owners 96 percent of the time.

Seven of the fifteen members of the Transmission Owners sector have very substantial investments in merchant generation.[185] Atlantic City Electric Company's parent, PHI, is a member of the Electric Distributors sector.

Some of the positions that PSE&G advocates at FERC are listed below.

- RPM Capacity Prices are too low to encourage new generation entry.[186]
  - The Cost of New Entry (CONE) should be increased automatically each year. .
  - The 2.5 percent Short-Term Resource Procurement Target in the base residual auction should be eliminated.[187]
  - The criteria for recognizing transmission additions in RPM planning assumptions should be more stringent.

[185] Allegheny, Constellation, Exelon, First Energy, PPL, PSE&G and NAEA Rock Springs. NAEA owns 1,755 MW of deregulated generation and does not have any apparent transmission ownership. The other eight members of the sector are: American Electric Power, Dominion, Duquesne Light, Dayton Power and Light, Consolidated Edison, UGI Utilities, Allegheny Electric Cooperative and Neptune Transmission System. Consolidated Edison owns Rockland Electric. UGI serves approximately 62,000 electric customers in Pennsylvania. Neptune owns a merchant submarine transmission line between New Jersey and Long Island.

[186] Response to Discovery, OC-861, Comments of the PSEG Companies in Opposition to Offer of Settlement, FERC Docket ER05-1410-000, January 9, 2009

[187] PJM reduces the amount of capacity that must be acquired in the RPM base residual auction by 2.5 percent for procurement in subsequent RPM incremental auctions. The purpose of the hold back is to increase demand response participation in the RPM by reducing the commitment lead time. The 2.5 percent hold back reduces BRA (Base Residual Auction) capacity prices by reducing the quantity of capacity that must be procured in the BRA.

  - Local delivery areas such as PSEG North should separate more frequently in RPM auctions. More stringent reliability criteria should be implemented to increase the frequency of separation of LDAs.
  - The avoidable cost-based bid caps for existing generation should be increased to reflect more rapid recognition of capital expenditures.[188]
- The PJM economic transmission expansion planning process should be eliminated. Alternatively, economic expansion projects should require a super-majority vote for approval.[189]
- PJM should increase payments to generators by implementing a scarcity pricing system. The scarcity revenues recognized in the RPM CONE energy revenue offset should be limited.[190]
- Utilities and merchant affiliates should be allowed to share all employees except transmission function and marketing function employees.[191]
- FERC's proposal to increase compensation for economic (energy) demand response should be rejected. Economic demand response should not be paid the full LMP as proposed by FERC.[192]
- PJM's capacity demand response programs should require year-round participation and allow unlimited curtailments of participant load. Demand response qualification requirements should be more stringent.[193]
- The RPM demand response participation caps proposed by PJM are to high. Demand response participation should be capped at lower levels.[194]

PSE&G strongly opposes state efforts to encourage the construction of new power plants by requiring utilities to enter into long-term contracts for default power supply.[195]

PSE&G's positions at FERC frequently coincide with those taken by generation interests. PSE&G explicitly endorsed the comments filed by generation groups in FERC RPM, demand response and scarcity pricing proceedings.[196]

A thorough evaluation of PSE&G's positions is beyond the scope of this audit. PSE&G's positions may or may not be in the best interests of retail customers. The alignment of PSE&G and generation owner

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[188] Comments of Gary Sorenson, Managing Director, PSEG Power LLC, On Behalf of PSEG Companies, FERC Docket ER05-1410-000, February 3, 2006 Technical Conference.

[189] PSEG Request for Rehearing, FERC Docket RM05-17-000, March 19, 2007.

[190] Comments of PSEG Companies, FERC Docket ER09-1063-004, July 30, 2010.

[191] Compliance Working Group, Amended Request for Clarification, FERC Docket RM04-7-007, October 28, 2009.

[192] Comments of PSEG Companies, FERC Docket RM10-17-000, May 13, 2010.

[193] Motion to Intervene and Protest of PSEG Companies, FERC Docket ER11-2288-000, December 23, 2010.

[194] Motion to Intervene and Protest of PSEG Companies, FERC Docket ER11-2288-000, December 23, 2010.

[195] Initial Comments of ER&T and PSE&G, New Jersey Capacity Issues Technical Conference, BPU Docket EO09110920, July 2, 2010 and Comments of Raymond DePillo on Behalf of the PSEG Companies, FERC Docket AD08-4-000, May 7, 2008.

[196] Response to Discovery, OC-861, Comments of the PSEG Companies in Opposition to Offer of Settlement, FERC Docket ER09-1410-000, February 23, 2009; Comments of the PSEG Companies, FERC Docket RM10-17-000, May 13, 2010 and Comments of PSEG Companies in FERC Docket ER09-1063-004, July 30, 2010.

positions raises concerns that PSE&G's positions are being shaped to advance the interests of its merchant generation affiliates.

Unified Position Development Process

The PSEG Services Corporation Vice President - Regulatory (PSEG VP - Regulatory) is responsible for establishing PSEG's unified corporate position on PJM and FERC issues.[197] The PSEG VP-Regulatory develops the unified positions with input from the utility's Director - Transmission Business Services (PSE&G Director - TBS) and ER&T's Managing Director - Market Development. The senior officers of PSE&G and ER&T also have input into the process.[198]

The PSE&G Director - TBS develops the utility position in consultation with PSE&G's President. The objectives of the utility positions are listed below.[199]

- Strengthening PSE&G's regulatory and business positions;
- Strengthening PSE&G's overall financial well-being;
- Ensuring transmission system safety and reliability.

The utility's objectives also implicitly include advancing the interests of its electric distribution customers.

Legal support for the development of the utility position is provided by the PSEG Services Corporation Law Department. Technical support is provided by PSE&G's Director - Electric Delivery Planning (Director - EDP) and Director - Electric Systems Operations.[200] The process rarely involves technical studies. PSE&G's philosophy is to support competitive markets. Strategy development is not prone to technical analysis.[201]

The PSEG VP - Regulatory considers the utility and ER&T positions and determines the unified corporate position. The unified corporate positions are coordinated and communicated through monthly RTO Issues (RTO) meetings.[202] The RTO meetings are held prior to PJM Markets & Reliability Committee (MRC) meetings and address the committee votes scheduled for the upcoming MRC meeting.[203]

The standing list of people invited to the RTO meetings is summarized below.

[197] Response to Discovery, OC-878, page 17 and Napoli interview.
[198] Napoli interview, October 8, 2010.
[199] Response to Discovery, OC-878, page 2.
[200] The Director -Electric System Operations supervises PSE&G's Electric System Operations Center (ESOC).
[201] Napoli interview, October 8, 2010.
[202] Response to Discovery, OC-190.
[203] Response to Discovery, OC-513.

Table 16-28 - PSEG RTO Issues Meetings Invitation List

PSEG RTO Issues Meetings Invitation List	
Company	Headcount
PSE&G	17
PS Power (including ER&T)	14
Service Company	27
PS Global	1
Total	59
Source: Response to Discovery, OC-190	

Typically, only five to ten people attend the RTO meetings. The meetings are one hour in length. The participants are informed of the unified corporate position at the RTO meeting. The participants discuss the unified corporate position. No votes are taken. However, the unified position can change as a result of the discussion at the meetings.[204]

PSEG also holds monthly Federal Regulatory Policy Team (FRPT) meetings to formulate and coordinate high level policy positions across the PSEG companies.[205] The FRPT meetings are one hour in length and review FERC and federal and state legislative matters.[206] The following table shows the team roster.

Table 16-29 - PSEG Federal Regulatory Policy Team Membership by Company

PSEG Federal Regulatory Policy Team Membership By Company	
Company	Headcount
PSE&G	3
PS Power (including ER&T)	3
Service Company	10
Total	16
Source: Response to Discovery, OC-190	

The process of developing the unified corporate positions includes extensive commingling of utility and merchant generation interests and views. The process also includes substantial sharing of utility and merchant generation information.

[204] Khadr interview, October 9, 2010.
[205] Response to Discovery, OC-190.
[206] Response to Discovery, OC-514.

PJM limits corporate families to a single vote on the Members Committee and MRC. PSEG's policy is that an ER&T employee will cast PSEG's vote in those committees.[207] Most PJM issues are market issues. ER&T has more knowledge of market issues than PSE&G. Therefore, an ER&T employee casts PSEG's vote.[208]

PSE&G recommended several changes to PJM/NYISO seams transmission planning and pricing procedures in 2010.[209] During interviews with Overland, PSE&G's Director -TBS and Director - EDP indicated they did not know how those proposals would impact energy prices in PSE&G's zone. The Director -TBS deferred the question to the Director - EDP, who deferred the question to ER&T. The Director - EDP stated the NYISO/PJM seams recommendations were "more of a market issue" and suggested someone in ER&T might be able to estimate the impact of PSEG's proposals on energy prices in PSE&G's zone.[210]

Relying on ER&T for expertise on market issues provides ER&T with an opportunity to shape utility positions to advance merchant interests. ER&T can unduly influence utility positions because of its superior knowledge of the issues.

Joint Legal Representation in PJM and FERC Matters

The Regulatory Section of the PSEG Services Corporation Law Department represents both PSE&G and ER&T in PJM and FERC matters. The Section is headed by PSEG's VP-Regulatory, Tamara Linde. She is responsible for: (1) determining PSEG's unified corporate position, (2) providing legal advice to the PSE&G Director - TBS in the development of the utility position; and (3) supervising the attorneys who represent PSEG in FERC matters.

The General Regulated Markets Counsel and the General Regulated Operations/Compliance Counsel both report to the VP-Regulatory. Those attorneys also provide legal support to the Director - TBS.[211]

The General Regulated Markets Counsel is Kenneth Carretta. He represents PSEG in most FERC proceedings that address PJM market rules. During the two years ending December 2009, 63 percent of his labor costs were charged to PS Power.[212] Mr. Carretta is PSE&G's primary attorney for BGS contracting matters.[213]

The General Regulated Operations/Compliance Counsel is Jodi Moskowitz. During the two years ended December 2009, 23 percent of her labor costs were charged to PS Power.[214]

The PSEG companies intervene as a corporate group in most FERC proceedings that address market rules. PSEG has a direct economic interest to favor the interests of merchant generators in those proceedings.

[207] Response to Discovery, OC-878, page 23
[208] Napoli interview, October 8, 2010.
[209] Request for Rehearing of PSEG Companies, FERC Docket ER08-1281-004, August 16, 2010
[210] Khadr interview, October 9, 2010.
[211] Napoli interview, October 8, 2010.
[212] Response to Discovery, OC-699.
[213] Response to Discovery, OC-1395 and Robinson interview, March 3, 2010.
[214] Response to Discovery, OC-710.

Joint representation provides an opportunity to shape the utility's positions to favor merchant generation interests.

Regulatory Oversight

The joint participation of utility and merchant generation interests in PJM and FERC matters creates a risk utility positions will be improperly influenced by merchant generation interests.

The incentives created by joint ownership of utility and merchant affiliates cannot be eliminated, but they can be managed. The two primary methods for managing the risks are operational separation and regulatory review.

Regulatory reviews assess whether the positions taken by PSE&G were improperly influenced by the interests of merchant affiliates. Adequate contemporaneous documentation of the basis for those positions promotes effective and efficient regulatory review.

The process used to develop PSEG's unified corporate positions is largely undocumented. The documentation is inadequate for the following reasons.

- The separate utility and PS Power positions are not documented; and
- The only documentation of the basis for PSEG's unified corporate positions are its FERC filings.[215] [216]

PSEG's FERC filings are prepared for litigation. The FERC filings advocate the unified corporate position and do not document opposing views within the PSEG corporate family.

The development of the unified position requires the balancing of utility and merchant interests. Determining whether the utility position or the merchant position prevailed in that balancing is difficult when the utility and merchant positions are not documented in writing.

Regulatory review of the unified positions is impacted by the following additional documentation deficiencies.

- PSE&G's Operational Excellence Model (OEM) calls for the preparation of an annual electric transmission strategic plan. PSE&G does not prepare a strategic plan or any other annual transmission strategy documents.[217]

[215] Napoli interview. The OEM for the Transmission Business Strategy Function was provided in Response to Discovery, OC-878. The OEM is in the third year of a four year development cycle and is subject to change.

[216] In its comments on Overland's report, PSE&G indicated that some documentation exists, but it was not made available to Overland on the basis of attorney-client and attorney work product privileges.

[217] Response to Discovery, OC-950 and Napoli interview, October 8, 2010.

- PSE&G's OEM calls for the Director - TBS to identify and track emerging issues. PSE&G does not list or track the emerging issues.[218]
- PSE&G's OEM calls for written reports to senior management on all significant issues. The written reports are supposed to include separate estimates of the impact of the issue on PSEG and PSE&G. No written reports are prepared.[219]
- The Law Department Regulatory Section provides a monthly "federal matrix" to the FPRT. The matrix is the primary written report on FERC matters.[220] According to PSE&G, the federal matrix is a legally privileged attorney work product that cannot be provided to Overland. PSE&G declined to provide a redacted version of the document.[221]
- PSEG does not track the votes it casts in PJM committee meetings.[222] The PJM Markets & Reliability Committee meeting notes identify the sector votes taken in that committee. The MRC does not publish voting reports. Overland asked PSE&G how it voted on 27 MRC sector votes. PSE&G indicated it did not have that information.[223]
- The only documentation for the RTO Issues meetings is the agenda. The agendas largely repeat the MRC agenda prepared by PJM. PSEG does not prepare any meeting notes for RTO Issues meetings.[224]
- The only documents regularly distributed within PSEG to keep managers and executives apprised of PJM activities and proposals are the agendas for the RTO and FPRT meetings.[225]
- PSEG prepares minutes for the FPRT meetings. According to PSEG, the minutes are a legally privileged attorney work product that cannot be provided to Overland.[226]

PSEG balances the interests of the utility's distribution customers and PS Power when formulating the unified corporate position. For example, issues pertaining to RPM capacity prices have a direct quantifiable impact on PS Power and electricity consumers. However, this balancing process is completely undocumented.

PSE&G should document the utility position. PSE&G should also document the PS Power position and the basis for selecting the unified corporate position. The documentation should explain the impact of the unified position on PSE&G's distribution customers and PS Power. The documentation should explain how PSEG balanced those impacts when selecting the unified corporate position.

[218] Response to Discovery, OC-950, OC-1207 and Napoli interview, October 8, 2010.
[219] Response to Discovery, OC-950, OC-1260 and Napoli interview, October 8, 2010.
[220] Napoli interview, October 8, 2010.
[221] Response to Discovery, OC-1065.
[222] Response to Discovery, OC-192, OC-510 and OC-1244.
[223] Response to Discovery, OC-1207.
[224] Response to Discovery, OC-513.
[225] Response to Discovery, OC-511.
[226] Response to Discovery, OC-1065.

Separate Utility Positions - Recommendations

Recommendation: PSE&G should develop and advocate separate utility positions on PJM and FERC issues.

PSEG has an economic incentive to advance the economic interests of generation owners. The development and advocacy of unified corporate positions increases the opportunities to respond to that incentive.

The process of developing unified corporate position transfers non-public merchant generation information to the utility. That provides an opportunity to influence utility policies.

The process also transfers non-public utility information to merchant affiliates. That creates the risk that preferential access to non-public utility information will provide the merchant affiliate with an unfair competitive advantage.

The joint development and legal advocacy of unified corporate positions creates risks for utility customers without any offsetting benefits. The utility should independently develop and advocate positions at PJM and FERC that advance the interests of its distribution customers, while preserving the utility's financial position.

PSEG should establish a separate legal group within the utility to support the development of the utility's positions and to advocate those positions at the FERC. Utility employees should be prohibited from participating in RTO and FPRT meetings.

Recommendation: If PSEG continues to vote a unified corporate position at PJM, it should join the generation owners sector.

PJM limits corporate families to a single vote on its two most senior committees. PSEG currently votes as a member of the Transmission Owners sector. If PSEG continues to vote in the Transmission Owners sector, its vote should reflect the independently developed utility position.

If PSEG continues to vote a unified corporation position at PJM, PSEG should join the Generation Owners sector. PS Power accounts for 75 percent of PSEG's consolidated net income. Merchant generation is PSEG's dominate business line. PSEG's sector designation should reflect the economic weight of the incentives influencing its vote.

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17. Interconnection and Non-Power Services

This Chapter addresses power supply affiliate relations issues pertaining to generation interconnection and non-power services. The Chapter is organized into the following sections.

- Generation interconnection process;
- Nuclear expansion transmission impact study;
- Interconnection agreements with PS Power;
- Station power; and
- Non-power goods and services.

Summary of Findings

1. FERC and PJM control over the interconnection process for new generation protects consumers against anti-competitive behavior. The interconnection process has not been a problem in PSE&G's transmission zone. Very few large generating plants have been proposed for PSE&G's zone.

2. PSE&G does not oppose or support merchant transmission projects that export power to New York City. According to PSE&G, it does not have the ability to discourage the development of those projects.

3. PSE&G prepared a transmission impact study for PS Power outside of the PJM interconnection process in 2009. The study identified network upgrades required to add a new nuclear unit adjacent to Salem and Hope Creek on Artificial Island. The study utilized ratepayer-funded resources and provided an opportunity to coordinate PSE&G's PJM transmission planning positions with PS Power's interests.

4. PJM only prepares transmission impact studies after the receipt of a valid interconnection application. Providing unpublished transmission impact studies to merchant generation affiliates without an interconnection application may provide an unfair competitive advantage to the affiliate.

5. PSE&G charged a lump-sum fee of $105,000 for the transmission impact study. PSE&G did not track the actual cost of preparing the study. Regulatory oversight of affiliate charges is difficult when the cost of providing the service is not tracked.

6. PSE&G standardized its interconnection agreements with PS Power in 2010. The new agreements will improve PSE&G's internal controls over interconnection service billings.

7. PSE&G's charges to PS Power for interconnection attachment facility maintenance appear to be reasonable with limited exceptions.

8. PSE&G did not charge PS Power for meter inspection and testing services provided prior to 2010. PSE&G will charge approximately $200,000 a year for those services under the new interconnection agreements.

9. PSE&G charged $7 million to PS Power for equipment maintenance and construction in 2009. PSE&G's internal controls over those charges are inadequate. From an internal control perspective, PSE&G treats the work it does for PS Power the same as utility work.

10. PS Power charged $16 million to PSE&G in 2009 for non-power goods and services. Most of the services were provided by PS Power's Maplewoods Testing Service (MTS), System Maintenance Division and Central Maintenance Shop.

11. The BPU's Holding Company Rules prohibit PSE&G from purchasing any services from affiliates that it can obtain "on more advantageous terms" by other means. The rules require PSE&G to review its purchases from PS Power for compliance with that requirement by April 2012.

12. PSE&G's internal controls over charges from PS Power are inadequate. From an internal control perspective, PSE&G treats charges from PS Power the same as internal utility charges. PSE&G does not implement any controls beyond those that apply to work it performs internally. PSE&G's management reports for charges from PS Power are inadequate.

13. The parties to the 1994 agreement are PSE&G, Pubic Service Enterprise Group and Enterprise Diversified Holdings, Incorporated. Schedule A to the agreement lists the services that PSE&G provides to Enterprise. The one page list of services is seriously outdated. All of the listed services are corporate administrative services currently provided by the PSEG Services Corporation. Article II describes the determination of cost-based charges. The description pre-dates SAP and is no longer accurate.

Recommendations

1. PSE&G should track the costs of preparing technical studies for PS Power.

2. PSE&G should charge PS Power for the interconnection metering costs it incurred but did not bill to PS Power prior to 2010.

3. PSE&G should compare reported station power values to benchmark values on a monthly basis.

4. PSE&G should charge tariff rates for station power delivered over local distribution facilities.

5. PSE&G should improve its internal controls over charges to PS Power.

6. PSE&G should enter into a Services Agreement with PS Power.

7. PSE&G should require PECO to stop depositing utility funds in a PS Power bank account.

8. The New Jersey Radiation Response Fund fee should be paid directly by PS Power.

9. PSE&G should review its purchases from PS Power for compliance with the BPU's Holding Company Rules.

10. PSE&G should improve its internal controls over charges from PS Power.

11. The reported station power values for PS Power's Essex, Bergen and Linden plants were below industry benchmarks in 2009.

12. PSE&G uses local distribution facilities to deliver station power to PS Power generating plants. PSE&G provides those services at a large discount from tariff rates. The discounts totaled approximately $4.3 million in 2009. PSE&G should charge tariff rates for those services. If PSE&G believes discounts are justified by a legitimate by-pass threat, it should provide estimates of PS Power's by-pass costs and explain its discounting strategy.

13. PSE&G should review the metering arrangements for the PS Power units located within its zone and prepare memoranda describing the station power and metering arrangements for each plant. The memorandum should:

    - Identify any station power take-offs that occur between the generator output terminal and the initial metering point;
    - Develop a reliable method for determining gross generation at the generator output terminals without any reductions for station power requirements;
    - Identify and describe station power take-offs that occur after the initial metering point;
    - Identify all external station power feeds serving the plant;
    - Estimate station power requirements for the plant and the expected power flow for each station power take-off and external feed; and
    - Describe the procedures for determining net generation for each plant.

Generation Interconnection Process

PS Power owns most of the utility-scale power plants interconnected with PSE&G's transmission system. The following table lists the generating stations with a capacity of over 40 MW that are interconnected with PSE&G's system.

Table 17-1 - Large Power Plants in PSE&G Zone

Large Power Plants In PSE&G Zone		
Plant	**Owner**	**MW**
Bergen	PS Power	1,199
Burlington	PS Power	557
Edison	PS Power	504
Essex	PS Power	617
Hudson	PS Power	991
Kearny	PS Power	447
Linden	PS Power	1,572
Mercer	PS Power	742
Sewaren	PS Power	558
Bayonne Cogen	Morris Energy Group	160
Camden Cogen	Morris Energy Group	145
Covanta Essex County	Covanta Energy	65
Eagle Point	Sunoco Power Generation	160
Elmwood Park	Morris Energy Group	67
Newark Bay	Morris Energy Group	120
Wheelabrator Falls	Wheelabrator Technologies	43
Source: PJM website, RPM Auction User Information, 2013/2014 Delivery Year, RPM Resource Model, 2/1/10, adjusted to eliminate post 2009 retirements. Note: Capacity is ICAP. Elmwood Park was previously Marcel Paper NUG.		

Two other large power plants are located within PSE&G's zone, but are not physically interconnected with PSE&G's transmission system. Those plants are listed below:

- Linden Co-Generation Plant - 645 MW plant completed in 1992;
- Bayonne Energy Center - 512 MW plant currently under construction.

The Linden Cogeneration plant and the Bayonne Energy Center are interconnected with the Consolidated Edison system through dedicated transmission lines to New York City.

PJM Generation Interconnection Process

FERC and PJM control the interconnection process for new generation. FERC Order 2003 sets out FERC's generation interconnection policies and requires standard interconnection agreements and procedures.[1] FERC requires independent management of the generation interconnection process to prevent anti-competitive behavior by transmission owners with generation affiliates.

PJM is responsible for managing the interconnection process consistent with FERC requirements. PJM's Operating Agreement, Open Access Transmission Tariff and Procedures Manuals describe the interconnection process and requirements in great detail.[2]

The Manager - Interconnection Planning, within PSE&G's Transmission Business Strategy Group, is responsible for administering PSE&G's interconnection agreements.[3] The Manager coordinates and reviews new ISAs and the interconnection arrangements for new plants with support from PSE&G Electric Delivery Planning and the PSEG Services Corporation Law Department.[4]

Generation developers are required to pay for the following facilities:

- Plant-side interconnection facilities. Interconnection facilities located on the generation owner's side of the interconnection point are constructed by the generation developer.

- Attachment facilities. Facilities on the transmission owner's side of the interconnection point that are directly required for interconnection.

- System upgrades. Enhancements to the transmission owner's system required to eliminate reliability criteria violations caused by new generating unit.

Attachment facilities are owned, constructed and maintained by the transmission owner. Interconnection revenue meters are used to measure the electricity injected into the transmission system. The revenue meters are attachment facilities and are typically owned by the transmission owner. The transmission owner owns, constructs and maintains the network upgrades.

Interconnection services can be separated into three phases; application, construction and operations. The generation developer initiates the application phase by contacting PJM and submitting an interconnection application. PJM assigns a project manager who is responsible for working with the developer.[5]

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[1] FERC Order 2003, Docket No. RM02-1-000, July 24, 2003.

[2] PJM website, Documents, Manuals, Manual 14A, Generation and Transmission Interconnection Process. Also Manual 14C, Generation and Transmission Interconnection Facility Construction.

[3] Response to Discovery, OC-198.

[4] Calore interview, March 3, 2010.

[5] PJM Manual 14A, page 4.

PJM groups the Interconnection applications into queues based on the application date. Each time-based queue is evaluated against a baseline benchmark of studies in order to establish project-specific responsibility for system upgrades.[6]

PJM requires the following three interconnection studies:

- Feasibility Study;
- Transmission Impact Study; and
- Interconnection Facilities Study.

The studies are prepared sequentially and the generation developer has the option of withdrawing the interconnection application after the completion of each study.

PJM is responsible for preparing and issuing the studies, with input from the transmission owner. PJM's planning models do not include low voltage local distribution facilities. PSE&G does the modeling for the distribution facilities that are not included in PJM's models.[7]

PJM assigns a system planning senior consultant to direct and lead the study phase.[8] PSE&G's Electric Delivery Planning Group provides PSE&G's input in to the PJM interconnection study process.[9]

The feasibility study assesses the practicality and cost of incorporating the new generation unit into the PJM system. The feasibility study includes preliminary estimates of the type, scope, cost and lead time for required network upgrades and attachment facilities.

The system impact study is a comprehensive regional analysis of the impact of adding new generation to the system. The impact study identifies system constraints and the necessary attachment facilities, local upgrades and network upgrades.[10] The system impact study refines the cost estimates included in the feasibility study.

The interconnection facilities study documents the engineering design work necessary to begin construction of required transmission facilities. The study also includes a good faith estimate of the cost to be charged to the generation developer for attachment facilities, local upgrades and network upgrades.[11]

PJM transfers team leadership to a PJM Project Coordinator after the interconnection facilities study is issued. The Project Coordinator manages the interconnection implementation phase. The Project

[6] PJM Manual 14A, page 6.
[7] Calore interview, March 3, 2010.
[8] PJM Manual 14A, page 9.
[9] Khadr interview, October 9, 2010.
[10] PJM Manual 14A, page 14.
[11] PJM Manual 14C, page 16.

Coordinator has the responsibility to ensure that all of the project activities, deliverables and milestones are achieved.[12] PJM makes site visits during the construction phase to assess the status of the work.

PJM has an interconnection project controls system that includes milestone and cost tracking. PJM controls the transfer of funds from the generation developer to the transmission owner. The transmission owner submits invoices to PJM for study work and the construction of attachment facilities and network upgrades. PJM reviews the charges and submits invoices to the generation developer. Once payment is received from the generation developer, PJM reimburses the transmission owner.[13]

Interconnection Process Safeguards

PSEG has an profit incentive to: (1) discourage competitors from constructing new power plants; and (2) require PJM market participants and PSE&G ratepayers to subsidize PS Power's interconnection costs. In the absence of regulatory oversight, a transmission owner could favor its generation affiliates by:

- Steering the affiliate to generation plant sites that do not require expensive network upgrades;
- Promoting the construction of transmission facilities that will reduce the affiliate's network upgrade costs;
- Requiring non-affiliates to pay excessive network upgrade costs;
- Undercharging affiliates for interconnection facilities;
- Delaying non-affiliate interconnections; and
- Using excessive transmission outages to deny non-affiliates access to the market.

Most transmission enhancement costs are charged, over their operating life, to firm transmission customers in proportion to their peak transmission demand. Interconnection network upgrade costs are charged directly to the generation developer. In the absence regulatory oversight, a transmission owner could reduce the interconnection network upgrade costs incurred by affiliates by constructing the upgrades before the affiliate enters the PJM interconnection queue.

PJM is responsible for bulk electrical system transmission planning.[14] That reduces PSE&G's ability to shape transmission expansion plans to benefit PS Power. FERC and PJM control the interconnection process for new generation, including planning studies and construction. That reduces PSE&G ability to require competitors to pay excessive interconnection costs and to delay the interconnection process.

PJM coordinates transmission and generation outages. Transmission owners are required to schedule transmission outages with PJM in advance. PJM reviews and approves the transmission outages. That

[12] PJM Manual 14C, page 14.
[13] PJM Manual 14C, page 22.
[14] Transmission planning affiliate issues are discussed in Chapter 16.

prevents utilities from benefitting their generation affiliates by forcing non-affiliated generators off-line for excessive transmission outages.[15]

Generation developers can file complaints at FERC if they are mistreated by the transmission owner. FERC and PJM control over the interconnection process protects consumers and ratepayers against anti-competitive behavior.

Interconnection Applications in PSE&G's Zone

Very few large new generating plants have been proposed for PSE&G's zone. The only significant generation additions in PSE&G's zone in the past eight years were the two new Linden combined cycle units completed in 2006. Those units were built by PS Power and have a total capacity of 1,260 MW.

According to PSE&G's Manager - Interconnection Planning, the high cost of transmission upgrades discourages the construction of new plants in PSE&G's service territory. Northern New Jersey's proximity to New York City increases the complexity of transmission system. New plants can trigger expensive upgrades due to the complexity of the area. The high cost of plant sites in Northern New Jersey also discourages new plants.[16]

The proposed generation in PSE&G's zone consists largely of small renewable energy methane and solar projects.[17] Off-shore wind developers are focusing on southern New Jersey.

Merchant Transmission Projects

Transferring power from northern New Jersey to New York City is the "holy grail" of merchant transmission line developers.[18] Merchant developers have built two lines from PSE&G's zone to New York City. Those lines are not interconnected with PSE&G's system. Instead, they connect the Linden Cogeneration Project and the Bayonne Energy Center directly to New York City. PSE&G has no interconnections with merchant transmission lines.[19]

Merchant transmission lines that transfer generating capacity from northern New Jersey to New York City have serious reliability implications for northern New Jersey and can require significant PJM system upgrades.

Developers have an option of designating their project as an energy only project. Energy only merchant transmission projects are not entitled to firm capacity withdrawals from the PJM system. The current

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[15] Response to Discovery, OC-520. The Morris Energy Group filed a complaint at FERC in January 2007 concerning a three month transmission outage at its Newark Bay plant. The outage stopped all power sales from the plant and interrupted station power service. The complaint was withdrawn after negotiations with PSE&G. Settlement terms, if any, were not disclosed.

[16] Calore interview, March 3, 2010.

[17] PJM 2009 Regional Transmission Plan, page 264 lists the projects as of December 2009.

[18] Calore interview, March 3, 2010.

[19] The Neptune Transmission line between Sayerville New Jersey and Long Island interconnects with the Jersey Central Power & Light System. PSE&G did construct some network upgrades in connection with that project.

trend along the Northern New Jersey / New York City interface is for merchant transmission developers to choose the energy only designation to reduce transmission upgrade costs.[20]

Merchant transmission lines from northern New Jersey to New York City increase energy and capacity prices in PSE&G's zone. PSE&G does not oppose or support individual merchant transmission projects that export power to New York City. PSE&G does not have the capability to impede their development, even if it wanted to do so. [21]

PSE&G participated extensively in the study process for the Hudson Transmission Project (HTP). PSE&G charged the developers at least $1.47 million for HTP transmission studies.[22] The HTP is a 660 MW controllable transmission line from PSE&G's Bergen substation to Consolidated Edison's 49th street substation in New York City. Construction is scheduled to begin in spring 2011 with completion in Spring 2013.[23]

The HTP developers originally proposed a firm capacity of 660 MW for the line. PJM estimated system upgrade costs of approximately $300 million, plus direct interconnection costs of $11 million. The developers reduced the firm capacity to 320 MW, with the remaining 340 MW treated as an energy only resource. That reduced the system upgrade costs to $180 million.[24]

PSE&G Study Fees and System Upgrade Charges

Interconnection planning study delays have not been an issue for PSE&G, as very few studies are prepared. PSE&G's Manager - Interconnection Planning is not aware of any complaints from generation developers about the interconnection process in PSE&G's zone.[25]

Some projects in other PJM zones with more activity have experienced delays. PJM is working to improve its interconnection process. If a backlog develops, PJM can hire consultants to prepare interconnection planning studies. PSE&G has a goal of streamlining the interconnection process for small renewable energy projects, and is working with PJM to accomplish that goal.[26]

PSE&G charged generation interconnection study costs to developers of $46,208 in 2009 and $37,211 in 2008. Excluding the HTP, PSE&G's merchant transmission study costs were $1,561 in 2009 and $17,101 in 2008.[27]

The following table shows PSE&G's network upgrade charges to generation developers during the five years ended December 31, 2009.

[20] Calore interview, March 3, 2010.

[21] Napoli and Khadr interviews, October 8 and 9, 2010.

[22] Response to Discovery, OC-708.

[23] Hudson Transmission Partners LLC website. HTP and the Cross Hudson Project are different projects. HTP is PJM merchant transmission queue number O66.

[24] Order Granting Certificate of Environmental Compatibility and Public Need, New York Public Service Commission, Case 08-T-0034, September 15, 2010, page 24.

[25] Calore interview, March 3, 2010.

[26] Calore interview, March 3, 2010.

[27] Response to Discovery, OC-708.

Table 17-2 - PSE&G Network Upgrade Charges to Generation Developers

PSE&G Network Upgrade Charges To Generation Developers Dollars in Millions			
Year	Plant	Owner	Amount
2006 & 2007	Linden	PS Power	0.4
2009	Prime Energy Co-generation	RPL Holdings	0.8
Total			1.2
Source: Response to Discovery, OC-968. Prime Energy Cogen is now named Elmwood Park, and is owned by Morris Energy Group.			

The Prime Energy Co-generation network upgrades were required by a 20 MW increase in the capacity rating for an existing plant.[28]

PSE&G completed two combined cycle units at Linden in 2006 with a total capacity of 1,260 MW. The Facilities Study Report for that project identifies $4.9 million in direct connection costs and $2.4 million in system upgrade costs.[29] The project included the retirement of 436 MW of existing capacity. The use of the existing capacity rights reduced the system upgrades required by the project.[30]

PS Power plans to begin construction of 267 MW of combustion turbine capacity at Kearny in the second quarter of 2011. The project is expected to be in service by June 2012. PS Power plans to retire three existing units at Kearny totaling 271 MW in 2012 and 2013.[31] The Facilities Study Report estimates $8.2 million of direct connection costs and $3.6 million of system upgrade costs.[32] The project claimed 178 MW of capacity rights from the retiring units at Kearny. That reduced the system upgrade costs by $11.6 million.[33]

The following table compares the network upgrade costs for recent large affiliated and non-affiliated interconnection applications in PSE&G's transmission zone.[34]

[28] PJM web-site, Generation Queue number R66.

[29] PJM web-site, interconnection request queue, number A4/C1.

[30] PJM web-site, interconnection request queue, number C1, Impact Study Report.

[31] PJM web-site, generation future deactivations list.

[32] PJM web-site, Facilities Study for interconnection queue numbers T41 and T42.

[33] PJM web-site, interconnection queue number T41, comparison of versions with and without use of Kearny Unit 10 and 11 capacity injection rights and T42 impact study.

[34] PJM does not disclose the generation developer's name in the initial feasibility study report. The developer's name is disclosed in the transmission impact report. The table is limited to projects that have a transmission impact report the PJM web-site.

Table 17-3 - System Upgrade Cost Estimates From Generation Interconnection Transmission Impact Studies

System Upgrade Cost Estimates From Generation Interconnection Transmission Impact Studies Dollars in Millions						
Report Date	Status Note 1	Sub-station	Owner	Net MW	Cost	Cost per KW
2002	C	Linden	PS Power	780	2	3
2006	W	Linden	Cavallo Power	600	60	100
2009	S	Essex	Hess Corporation	625	155	247
2009	W	Hudson - Essex	Duke Energy	455	59	129
2009	W	Essex	PS Power	176	11	62
2009	S	Essex	PS Power	176	14	81
2009	S	Hudson	PS Power	205	16	77
2009	W	Metuchen	Competitive Energy Ventures	600	21	35
2010	UC	Kearny	PS Power	89	4	40

Note 1: C is completed; UC is under construction; S is under study and W is withdrawn.
Source: PJM web-site, interconnection queues, active and withdrawn projects, A4, C1, T41, T42, T43, T44, T45, T107, T119, Q86.

The two PS Power Essex projects are closely related. PS Power submitted two applications covering eight 44 MW combustion turbine units. The withdrawn application covers the last four of those units.[35]

System upgrade costs for PS Power projects tend to be lower than those for non-affiliated projects. The PS Power projects averaged $33 per Kw. The non-affiliate projects averaged $129 per Kw.

Nuclear Expansion Transmission Impact Study

PSE&G entered into Study Work Agreement with PS Power in March 2009 to prepare a transmission impact study of adding a new nuclear unit in the year 2021. The new unit would be located adjacent to Salem and Hope Creek on Artificial Island (AI).[36]

PS Power anticipated that adding a new unit at AI would require significant system upgrades. PS Power requested the study to assist in the management decision process prior to submitting an interconnection request to PJM.[37] PSE&G issued the transmission impact study report in July 2009. The study was prepared outside of the PJM interconnection process.

[Begin Confidential]

[35] PJM interconnection queue numbers T43 and T44.
[36] Response to Discovery, OC-502.
[37] Response to Discovery, OC-502.
[38] Response to Discovery, OC-711.

[End Confidential]

The study was prepared by PSE&G's Electric Delivery Planning group. PSE&G charged PS Power a lump sum fee of $105,000 for the study.[43]

The study was developed with PSE&G's system planning models. The models are vendor products. PJM uses the same vendor products. The basic data files used in the study were obtained from PJM and are available to all generators.[44]

The study relied on the engineering judgment and expertise of PSE&G's system planning engineers. The simulation of faults is an integral part of stability studies. PSE&G's power flow model allows users to create macros used to run simulations from applying the fault, clearing the fault and running the simulation post fault to look for system response. The study used 14 macros developed by PSE&G's Electric Delivery Planning group.[45]

The March 2009 study agreement required PSE&G to transfer all electronic files and macros associated with the study simulations to PS Power in electronic format.[46] PSE&G did not transfer the files to PS

[39] The base case included all PJM approved 500 kv transmission projects.
[40] Seashore Loop includes constructing a new line from New Freedom to Smithburg.
[41] Response to Discovery, OC-711.
[42] Response to Discovery, OC-711.
[43] Response to Discovery, OC-1057.
[44] Khadr interview, October 9, 2010, and Response to Discovery, OC-974.
[45] Response to Discovery, OC-1439. PSE&G uses the Power System Simulator for Engineering (PSS/E) model under a license agreement with Siemens. PSS/E is a standard industry model. Response to Discovery, OC-713 and OC-1439.
[46] Response to Discovery, OC-502, March 2009 Study Work Agreement, Section 2, Scope of Work.

Power because the model data was Critical Energy Information Infrastructure Information (CEII). PSE&G does not have authority to release CEII to any affiliated or non-affiliated generator.[47]

Providing merchant generation affiliates with preferential access to ratepayer funded resources provides an unfair competitive advantage to the affiliate. The study is the only time that PSE&G has prepared a transmission impact study for a generation developer prior to the submission of an interconnection application to PJM.[48] According to PSE&G, if a non-affiliated developer requested a similar study, it would fulfill that request.[49]

PJM only prepares transmission impact studies after the receipt of a valid interconnection application. The interconnection application establishes the developer's position in the interconnection queue, which impacts the developer's cost responsibility for transmission upgrades. PJM publishes the transmission impact studies it prepares on the PJM website.

Providing unpublished transmission impact studies to merchant generation affiliates without requiring an interconnection application may provide an unfair competitive advantage to the affiliate.

Preparing the study provided PSE&G with information about the system upgrades required for a new nuclear unit at AI. Load serving entities pay for most transmission enhancements through transmission rates. Generation developers pay directly for system upgrades required by generation additions. PSEG has an incentive to promote transmission enhancements that will reduce PS Power's system upgrade charges. The study provided an opportunity to coordinate PSE&G's transmission planning positions with PS Power's interests.

[Begin Confidential]

[47] Response to Discovery, OC-714.
[48] Khadr interview, October 9, 2010.
[49] Response to Discovery, OC-1323.
[50] Response to Discovery, OC-1324, page 3
[51] Response to Discovery, OC-1324, page 4

[End Confidential]

PSE&G's advocacy of the Northern Option illustrates the concern that a utility will modify its transmission planning activities to minimize system upgrade costs for its merchant generation affiliates. The information PSE&G obtained by doing the transmission impact study may have influenced its advocacy for the Northern Option. That concern is tempered by the long time frame of PS Power's nuclear expansion plans.[55]

[Begin Confidential]

[End Confidential]

Recommendation: PSE&G should track the costs of preparing technical studies for PS Power.

The March 2009 study agreement included a cost estimate of $105,000 for the transmission impact study.[57] The estimate was "based on prior experience in developing other feasibility studies for the PJM interconnection process."[58]

PSE&G estimated the study would require 440 hours of effort. PSE&G did not retain any support for the estimated hours. The $105,000 cost estimate was calculated by multiplying the estimated hours by an average hourly billing rate of $231, and adding a contingency provision of $3,360.[59] PSE&G uses the same average hourly billing rate for PJM studies.[60]

52 PJM web-site, TEAC Meeting, May 27, 2010, Reliability Analysis Update presentation, page 14.

53 Response to Discovery, OC-1324, page 12

54 PJM website, TEAC October 6, 2010 meeting, Reliability Analysis Update presentation, page 19

55 PSE&G advocated in favor of the Northern Option based on system reliability concerns, including concerns about voltage stability at Artificial Island.

56 Khadr interview

57 Response to Discovery, OC-504, March 2009 Study Work Agreement, Section 6

58 Response to Discovery, OC-1057

59 Response to Discovery, OC-1057

60 Response to Discovery, OC-715

PSE&G did not track the actual costs of preparing the study. The PSE&G employees who worked on the study did not track their time.[61] [62]

PSE&G did not prepare an invoice for the charges. The lump-sum fee was paid through the inter-company settlement process in July 2009. PSE&G credited the fee to Account 421, Miscellaneous Non-operating Income.[63]

The scope of the study was expanded to include the Peach Bottom to AI line after preliminary results were reviewed with PS Power. The lump-sum fee was not modified to reflect that expansion. Given that PSE&G did not track the labor hours worked on the study, determining whether the 440 hours included in the fee were sufficient to accommodate the scope expansion is not practical.

PSE&G did not attempt to estimate the market value of the transmission impact study. PSE&G did not ask PS Power why it wanted PSE&G to prepare the study instead of having an engineering firm or PS Power employees prepare the study.[64] PSE&G did not attempt to estimate what an engineering firm would have charged for the study.[65]

Regulatory oversight and operational separation are the primary safeguards against cross-subsidization. Regulatory oversight of affiliate charges is difficult when the costs of providing the services are not tracked. PSE&G should track the labor hours and costs of providing service to PS Power.

Interconnection Agreements with PS Power

PSE&G entered into new Interconnection Services Agreements (ISAs) with PS Power in late 2009. PSE&G's prior interconnection agreements with PS Power pre-dated FERC Order 2003 and did not conform with the PJM standard interconnection agreement.[66]

The new ISAs use the standard PJM three party agreement (The three parties are PJM, PSE&G and PS Power). The standard terms were not subject to negotiation or modification. The attachments to the agreement are the only parts that vary from station to station.[67]

The new ISAs include all of PS Power's plants located within PSE&G's transmission zone. The new ISAs were effective on December 11, 2009.[68]

[61] Response to Discovery, OC-1057

[62] PSE&G states that efforts are underway to reinforce timekeeping processes, which are required for PSE&G employees.

[63] Response to Discovery, OC-716

[64] Response to Discovery, OC-1323.

[65] In its comments on this report, PSE&G noted that PSE&G's charge to PS Power was materially higher than the average PJM charge for similar studies.

[66] Response to Discovery, OC-66 and OC-204.

[67] Response to Discovery, OC-1061.

[68] Response to Discovery, OC-705.

The PJM standard agreement provides for the following items to be billed to interconnection customers.[69]

- Administration charge;
- Metering charge;
- Telemetering charge;
- Attachment facility O&M charges; and
- Other mutually agreed upon charges.

Under the new ISAs, all PSE&G charges to PS Power will pass through PJM. PSE&G will bill PJM, who will review the charges and bill PS Power. After receiving payment from PS Power, PJM will reimburse PSE&G.[70]

PJM is developing a standardized billing process for ISA charges. PSE&G did not bill PS Power for interconnection services in 2010 because of delays in developing that process. PSE&G is working with PJM and will retroactively bill PS Power once the billing process is finalized.[71]

The new ISAs will improve controls over interconnection service billings. Prior to the new ISAs, the charges were settled through inter-company receivable accounts without invoicing. PJM's involvement in the billing process will improve cost tracking and reporting.

PSE&G does not bill PS Power or any of its other interconnection customers for administrative activities.[72] Telemetering costs are apparently included in PSE&G's charges to PS Power for energy management system access.[73] PSE&G charges its NUG interconnection customers $5,000 to $12,000 a year for telecommunications circuits.[74]

Meter Inspection and Testing Charges

PSE&G owns and maintains the revenue meters used to measure the output of PS Power's generating units.[75] The PJM Standard Interconnection Services Agreement allows transmission owners to charge interconnection customers for metering operations, maintenance, inspection, testing and replacement costs.

PSE&G transferred its power plants to PS Power in 2000.[76] In accordance with the service agreements filed with FERC and the New Jersey BPU, PSE&G did not charge PS Power for meter inspection and testing during the years 2000 through 2009.[77] PSE&G will charge PSEG Fossil for metering services under

[69] PJM OATT, Attachment O, Appendix 2, Standard Terms and Conditions, Section 10.
[70] Response to Discovery, OC-706 and OC-969.
[71] Response to Discovery, OC-1443 and OC-1261.
[72] Response to Discovery, OC-706, administrative activities include billing and processing generation data.
[73] EMS charges are discussed in Chapter 16.
[74] Response to Discovery, OC-689 and OC-445.
[75] Response to Discovery, OC-200.
[76] PSEG website, About PSEG, history tab.
[77] Response to Discovery, OC-969.

the New ISA.[78] PSE&G estimates it will charge PS Power $195,233 for meter testing and calibration costs incurred in 2011.[79]

Recommendation: PSE&G should charge PS Power for the interconnection metering costs it incurred but did not bill to PS Power prior to 2010.

Interconnection metering costs would not be incurred but for the existence of the generating plant. The metering costs are the responsibility of the generation owner under FERC policy. PSE&G should retroactively bill PS Power for the metering costs incurred prior to the effective date of the new ISAs.

The original 1999 Service Agreements did not provide for metering charges. Given an arms-length relationship PSE&G would have had an incentive to modify the agreements to provide for metering charges as FERC policies evolved. PSE&G and PS Power do not have an arms-length relationship, and metering charges were not implemented in a timely manner. Applying FERC policies produces the best available proxy for the result that would have occurred with an arms-length relationship.

Attachment Facility Maintenance Charges

Attachment facilities include all of the utility-owned local transmission facilities required to connect the generating plant to the transmission facility. The criteria for identifying attachment facilities is the “but for” standard. If a utility owned facility would not be needed but for the existence of the generating unit, the generator is charged for the maintenance of that facility. The “but for” standard is FERC policy and is incorporated into the PJM Open Access Transmission Tariff.[80]

The Attachment Facilities are identified in the interconnection facilities study and are listed in an attachment to the ISA. Attachment facilities typically consist of meters and system protective devices including switches, breakers and relays.[81]

Attachment facility maintenance is scheduled and performed using PSE&G’s normal transmission maintenance procedures. Attachment facility maintenance is performed by the Electric Division in which the plant is located. The Metering Group in PSE&G’s customer operations department inspects and tests the revenue meters.[82]

Attachment facility O&M is charged based on PSE&G’s actual cost of performing the service. The prior ISA for the plants PSE&G transferred to PS Power did not provide for charging attachment facility maintenance costs to PS Power.[83] The charges to PS Power were settled through inter-company accounts without an invoice.[84]

[78] The new ISAs were effective on December 11, 2009.
[79] Response to Discovery, OC-1412.
[80] Calore interview, March 3, 2010.
[81] Response to Discovery, OC-1203.
[82] Calore interview, March 3, 2010.
[83] Calore interview, March 3, 2010, and Response to Discovery, OC-66, page 73.
[84] Response to Discovery, OC-969 and Calore interview.

The Manager of Interconnection Planning was not responsible for O&M billings under the prior ISA. The Manager did not review the charges to PS Power for completeness and does not know if anyone else did.[85]

The invoices for non-affiliated plants are prepared by PSE&G's Third Party Billing Department.[86] The Manager - NUG Contracts reviews and administers those charges.[87]

PSE&G's attachment facility maintenance charges averaged $473,821 a year during the five year period ended in 2009. That average includes $357,347 for PS Power plants and $116,474 for non-affiliated plants.[88]

The following table summarizes PSE&G's attachment facility maintenance charges to PS Power for 2005 through 2009.

Table 17-4 - PSE&G Attachment Facilities Maintenance Charges to PS Power

PSE&G Attachment Facilities Maintenance Charges to PS Power Five Years Ended December 2009			
Plant	**ICAP MW**	**Five-Year Charges**	**Per MW**
Bergen	1,199	91,654	76
Burlington	557	142,788	256
Edison	504	65,807	131
Essex	617	141,565	229
Hudson	991	285,257	288
Kearny	447	224,531	502
Linden	1,572	399,361	254
Mercer	742	433,286	584
Sewaren	558	2,486	5
Total	7,187	1,786,735	249

Source: Response to Discovery, OC-970. ICAP per RPM Resource Model

The charges to PS Power are plausible with the exception of Sewaren. The Bergen and Essex charges are also substantially below average.

[85] Calore interview, March 3, 2010.
[86] Response to Discovery, OC-969.
[87] Calore interview, March 3, 2010.
[88] Response to Discovery, OC-970

The attachment facilities charges for non-affiliated plants are shown below.

Table 17-5 - PSE&G Attachment Facilities Maintenance Charges to Non-Affiliates

PSE&G Attachment Facilities Maintenance Charges to Non-Affiliates Five Years Ended December 2009			
Plant	ICAP MW	Five-Year Charges	Per MW
Bayonne Cogen	160	201,473	1,259
Camden Cogen	145	14,330	99
Covanta Essex Co.	65	56,301	866
Eagle Point Cogen	160	62,966	393
Elmwood Park	67	0	0
Newark Bay Cogen	120	229,281	1,911
Wheelabrator	43	18,017	419
Total	760	582,368	766
Source: Response to Discovery, OC-970. ICAP per RPM Resource Model			

The average per MW charge to non-affiliates is more than triple the average charge to PS Power. That difference may be at least partially explained by the smaller average size of the non-affiliated plants.[89]

PSE&G should provide a memorandum in its response to this report that explains the reasons why:

- Sewaren, Bergen and Edison charges were low in 2005 - 2009;
- Elmwood Park was not charged for attachment facility maintenance during that period; and
- Camden and Newark Bay charges were much higher than average during that period.

Station Power

All generating plants consume electricity in their operations. Examples of station power requirements include electricity used for:[90]

- Re-starting generators after they have been shut down;
- Operating emissions control equipment;
- Pumping and treating cooling water;
- Operating fuel handling equipment;
- Lighting, heating and cooling plant buildings.

[89] The average non-affiliate plant size is 108 MW. The average PS Power plant size is 799 MW.
[90] PJM Manual 14A, page 31.

Most station power is self-supplied by the plant when it is operating. During those periods, station power accounts for the difference between gross generation and net generation. Gross generation is the output of the electrical generator measured at the generator output terminals. Net generation is the amount of electricity provided to the transmission grid.

When the plant is not operating, station power must be provided through external sources. Station power can be provided over the plant's transmission interconnection when the plant is not operating. Station power can also be provided through local distribution lines regardless of whether the plant is operating or not.

Station power typically consumes three to six percent of gross generation. However, station use for coal plants can be as high as 12 percent because of pollution control and coal handing equipment.[91]

A recent California Energy Commission Report surveyed the gross and net generation of 25 modern combustion turbine plants and 15 combined cycle plants. Station power requirements consumed 2.9 percent of the gross generation of the combined cycle plants and 3.4 percent of the gross generation of the combustion turbine plants.[92] Gas and Coal steam plants have higher station power requirements.

Prior to deregulation, utilities frequently metered gross generation and estimated station use, resulting in an estimated net generation value. In a deregulated environment, accurate measurement of net generation is important because it is the basis for paying the generator.

The revenue meter is typically installed on the high side of the plant step-up transformer. Any station power off-takes past that point must be metered and deducted to determine net generation.

BGS and Third Party Retail Supplier loads are determined by summing the net generation in PSE&G's zone and adding or deducting net interchange. Overstating net generation increases BGS-FP load and the resulting payments to BGS suppliers.

System lost and unaccounted for energy (system losses) is the difference between system inputs and retail energy deliveries. Overstating net generation increases the reported system losses. Energy consumers, including BGS-FP customers, pay for system losses.

PSE&G calculates the net generation values reported to PJM. The normal protections provided by an arms-length transactions do not apply when PSE&G reports those values. Regulatory oversight is needed to ensure consumer interests are protected.

[91] Measurement of Net Versus Gross Power Generation, First Energy Corporation, January 27, 1999, US Environmental Protection Agency web-site, Clean Air Markets, Documents.

[92] Comparative Costs of California Central Station Electricity Generation, August 2009, California Energy Commission, page C-14.

Station Power Benchmarking

PSE&G provided descriptions of the methodology it uses to determine the net generation of each PS Power generating unit located in PSE&G's transmission zone and gross generation and station power deductions for each unit by month.[93]

The following table shows gross generation amounts and station power deductions reported by PSE&G for the PS Power generating plants located in PSE&G's zone.

Table 17-6 - PS Power Generating Units Gross Generation and Station Power Take-Offs

PS Power Generating Units Gross Generation and Station Power Take-Offs 2009 - MWH				
Plant	MW Capacity	Gross MWH	Station Power MWH	Percentage
Bergen	1,199	4,975,112	84,969	1.7
Burlington	557	71,508	4,951	6.9
Edison	504	44,980	1,766	3.9
Essex	617	98,890	1,686	1.7
Hudson	991	1,566,053	151,291	9.7
Kearny	447	79,118	11,444	14.5
Linden	1,572	4,126,317	33,223	0.8
Mercer	742	1,589,428	163,724	10.3
National Park	21	27	133	494.1
Swearen	557	47,287	17,408	36.8
Total	7,207	12,598,720	470,595	3.7
Source: Response to Discovery, OC-504. Station power adjusted to include retail feeds from PSE&G (Response to Discovery, OC-202).				

Hudson and Mercer are coal plants. A reasonable station power benchmark for a coal plant is 10 to 12 percent. Sewaren is largely a gas steam plant. The Sewaren steam units were well over fifty years old in 2009. Sewaren operates at a very low capacity factor. Sewaren's age and low capacity factor may explain why its station power percentage is significantly higher than the benchmark.

Essex, Edison, Burlington and Kearny are combustion turbine plants. A reasonable benchmark for combustion turbine plants in 3.4 percent. The Bergen and Linden are modern combined cycle plants. A reasonable benchmark for Bergen and Linden is 2.9 percent.

The Essex, Bergen and Linden station power percentages are below the benchmark values. The following situations could explain the lower than expected values:

[93] Response to Discovery, OC-504.

- Some station power take-offs occur before the initial measurement of gross generation;
- Some station power take-offs after the initial measurement of gross generation are not metered or are metered inaccurately and;
- The plant has retail station power feeds that are not metered.

In its comments on this project, PSE&G provided the following explanation for why: (1) the Essex, Bergen and Linden station power percentages are significantly lower than the benchmark values, and (2) the values reported for Kearny and Sewaren are higher than the benchmark.

Detailed below are some of the significant reasons that PSEG Power units would differ in the need for internal power.

> **Essex:** It should be recognized that the generating units located at Essex station are simple cycle units, but they are not LM6000 units that are utilized in the referenced CA benchmark analysis. As the LM6000 units likely have additional station service load (for water injection and possibly gas compression) as compared to the units at Essex, the station loads for Essex can be expected to be less than those of LM6000 units.
>
> **Bergen and Linden:** For Linden units 1 and 2, and Bergen unit 2, the revenue metering is measuring net output of the units (i.e. the station service "take-offs" occur before the metering). As such, when the units are generating, they are self-supplying station service (thus separate station service values are not available and were not provided for in the referenced discovery requests), this results in station power percentages 'lower than the benchmark values' in the report.
>
> **Sewaren:** During 2009, the Sewaren station had a relatively low capacity factor, resulting in a higher station percentage (as a percentage of gross output). Utilizing the capacity factor equation contained within the referenced CA study, the Sewaren units would have a combined capacity factor of roughly 0.62%, which is generally much lower than the units contained within the study.
>
> **Kearny**: There are several factors that cause the Kearny station service values to be high relative to the referenced benchmarks. First, the Kearny station includes four operating units, Kearny 9, 10, 11, and 12. Three of these units (9, 10, 11) have very low capacity factors, which would result in a relatively high station service percentage as compared to the benchmark (utilizing the capacity factor equation contained within the referenced CA study, the Kearny units would have a combined capacity factor of roughly 1.6%, which is generally much lower than the units contained within the study). Additionally, the station service values included in the report for Kearny appear to include the load associated with synchronous condenser operations, which is not station service. If the synchronous condenser load is accounted for, the station service percentage falls to roughly 10%. Also, there are station service loads at Kearny that might not be consistent with those CA facilities included in the study, including loads associated with an on-site facility that contain two retired generating units (Kearny 7 & 8), administrative facilities, fuel oil heating equipment, and a water treatment facility for the entire site.

PSE&G's internal controls over the measurement of net generation are summarized below:[94]

- PSE&G tests the meters installed at generation stations.
- PSE&G compares the meter data to instantaneous values reported for operational purposes on a daily basis.
- PSE&G analyzes total system losses on a monthly basis when they deviate from the expected value by more than one percent of total load.
- PSE&G compares the data it sends to PJM to values it receives from PJM to identify any data issues that might have occurred in the upload of data to PJM.
- PSE&G reviews the calculation of net generation at each plant on a monthly basis to identify missing data.

PSE&G has not conducted any internal audits of the process used to determine net generation in recent years.[95]

The critical control is the comparison of the revenue meter data to the instantaneous system operations data. The instantaneous data is generated by transducers, potential transformers and current transformers located in PSE&G switchyards and substations. [96] If the measurements are taken in the right place and are accurate, the comparison should identify significant differences between reported and actual net generation. The comparison would not identify unreported retail station power feeds.

In theory, over or under statements of net generation could be discovered by analyzing system losses. Unfortunately, the factors impacting system losses are difficult to isolate and analyze and persistent overstatements of net generation can go undetected for long periods of time.[97]

PSE&G does not use industry benchmarks to evaluate reported station power values. The failure to identify and meter station power take-offs is a key risk for ratepayers. Comparing reported station power values to industry benchmarks provides a basis for identifying unidentified station power use. The benchmark value represents the expected level of station power. Comparing planned and actual values is a key component of internal controls.

PSE&G should develop benchmarks for assessing the reasonableness of reported station power values. The benchmarks should reflect the generating unit technology. The benchmarks should include the

[94] Response to Discovery, OC-1410.

[95] Response to Discovery, OC-730.

[96] Transducers measure voltage and other operating parameters. Potential transformers measure the voltage flowing through a conductor. Current transformers measure the amperage flowing through a conductor.

[97] Management Audit of Atlantic City Electric Company, conducted for the BPU by Overland Consulting, 2008, Chapter 4. The Deepwater Generating Plant station power reporting error went undetected for nearly four years. On a smaller scale, retail station power feeds for the Missouri Avenue and Cumberland power plants went unreported for almost nine years.

expected percentage of gross generation consumed as station power and minimum requirements when the plant is not operating. PSE&G should compare the reported station power values to the benchmark values each month and investigate significant variances.

A critical step is ensuring the benchmark and reported values reflect the same definition of station power. The benchmark and reported values should reflect the difference between gross generation measured at the generator output terminals and the net generation delivered to the transmission grid.

Gross electrical output at the generator terminal is an important operating control parameter. Power plants are typically designed with direct metering of gross electric output.[98]

PSE&G should review the metering arrangements for the PS Power units located within its zone and prepare memoranda describing the station power and metering arrangements for each plant. The memorandum should:

- Identify any station power take-offs that occur between the generator output terminal and the initial metering point;
- Develop a reliable method for determining gross generation at the generator output terminals without any reductions for station power requirements;
- Identify and describe station power take-offs that occur after the initial metering point;
- Identify all external station power feeds serving the plant;
- Estimate station power requirements for the plant and the expected power flow for each station power take-off and external feed; and
- Describe the procedures for determining net generation for each plant.

PSE&G should attach one line diagrams for each plant to the memorandum showing the electrical generators, step-up transformers, station power take-offs, retail feeds and meters relevant to understanding the process for determining net generation.[99] The memoranda should explain and enhance the diagrams to make the metering process more understandable.

Station Power - Distribution Facilities Charges

PSE&G delivers station power to PS Power over local distribution facilities under two different types of arrangements:

[98] Measurement of Net Versus Gross Power Generation, First Energy Corporation, January 27, 1999, US Environmental Protection Agency web-site, Clean Air Markets, Documents.

[99] Several of the new ISAs have one line diagrams attached. One line diagrams were not provided for Essex and Linden. Response to Discovery, OC-705.

- Retail accounts - treated as a retail sale to PS Power under PSE&G's BPU tariffs. The energy delivered to the plant is not deducted from net generation.[100]

- Facilities charges - treated as delivery of electricity generated by the plant to the plant using local distribution facilities. PSE&G charges PS Power a facilities charge for the use of the distribution facilities. The delivered energy is deducted from the plant's net generation.[101]

The following table shows those deliveries by type in 2009.

Table 17-7 - Station Power Deliveries to PS Power Using Local Distribution Facilities

Station Power Deliveries To PS Power Using Local Distribution Facilities 2009 - MWH	
Type	**MWH**
Retail Account	2319
Facilities Charge	142,633
Total	144,952
Source: Response to Discovery, OC-1264 and OC-1444	

The retail account deliveries are billed under PSE&G's General Lighting and Power (GLP) Service and Large Power and Lighting (LPL) Service tariffs.[102]

The Facilities Charge (FC) deliveries are deducted from gross generation to determine each plant's net generation. FC deliveries represented about 30 percent of the station power deducted from gross generation in 2009.

Most of the FC deliveries are for the Hudson Plant, as shown in the following table.

[100] Response to Discovery, OC-200 and OC-202.
[101] Response to Discovery, OC-757.
[102] Response to Discovery, OC-200.

Table 17-8 - PSE&G Station Power Facilities Charges by Plant for 2009

PSE&G Station Power Facilities Charges By Plant for 2009 Dollars in Thousands			
Plant	MWH	Charge	Cents per KWH
Bergen	6,944	42	0.6
Burlington	1,930	28	1.4
Hudson	119,535	235	0.2
Linden	1,707	28	1.6
Sewaren	12,517	64	0.5
Total	142,633	397	0.3
Source: Response to Discovery, OC-1264 and OC-522			

The FC deliveries are made over 26 Kv local distribution circuits originating from PSE&G distribution switchyards. The distribution switchyards and circuits are owned by PSE&G and included in Plant Account 362, Distribution Plant Station Equipment.[103]

The Hudson FC circuits originate at PSE&G's Marion Switchyard. The station power is transmitted from the Marion Switchyard to the plant site over three 26 kv circuits that range from 1,545 feet to 1,600 feet in length.[104]

The Bergen FC circuits originate at the Bergen Switchyard. The station power is transmitted from the Bergen Switchyard to the plant site over two circuits that are both 3,500 and 4,500 feet long.[105]

The distribution switchyards and circuits are included in PSE&G's distribution rate base. The facility charge revenue is recorded in PSE&G Revenue Account 442, Commercial and Industrial Sales.[106]

The facility charges are calculated by applying a carrying charge rate to the original cost of specific distribution facilities. The facility charge calculations are summarized below.

[103] Response to Discovery, OC-1264.
[104] Response to Discovery, OC-1263.
[105] Response to Discovery, OC-1263.
[106] Response to Discovery, OC-1264.

Table 17-9 - Station Power Facilities Charges

Station Power Facilities Charges Amounts in Thousands	
Description	**Amount**
Directly Assigned Plant Cost	594
Allocated Common Plant Costs	1,557
Total Plant Costs	2,151
Annual Carrying Charge Rate	18.48%
Annual Facility Charge	397
Source: Response to Discovery, OC-1264 and OC-522	

The carrying charge rate is the rate specified in PSE&G's BPU tariffs for facilities charges.[107]

The directly assigned plant consists of the circuits that link the distribution switchyard to the plant site, including cable, switches, breakers and poles. The common facilities consist of the electrical buses located in the distribution switchyards that originate the circuits. The distribution buses are part of PSE&G's integrated 26 Kv distribution system and are used to distribute power to all of the distribution circuits originating at the switching station.[108]

The distribution bus costs are allocated based on station power maximum demand and maximum bus capacity. The following table shows the allocation factors.

Table 17-10 - Station Power Facility Charges Common Plant Allocation Factors

Station Power Facility Charges Common Plant Allocation Factors			
Plant	**Station Power Demand (MW)**	**Maximum Bus Capacity (MW)**	**Allocation Factor Percent**
Bergen	6	330	1.82
Burlington	1.5	108	1.42
Hudson	41.2	376	10.97
Linden	1.8	149	1.23
Sewaren	12.6	255	4.96
Source: Response to Discovery, OC-1264			

107 Response to Discovery, OC-757 and PSE&G Tariff Sheet 14, Standard Terms and Conditions, Section 4.5.2

108 Response to Discovery, OC-1263

The common plant allocation is shown below.

Table 17-11 - Station Power Facility Charges Common Plant Allocation Dollars

Station Power Facility Charges Common Plant Allocation Dollars Dollars in Thousands			
Plant	Common Bus	Factor	Amount
Bergen	6,017	1.82	109
Burlington	7,429	1.42	105
Hudson	9,280	10.97	1,018
Linden	3,305	1.23	41
Sewaren	5,716	4.96	284
Total	31,747	4.9	1,557
Source: Response to Discovery, OC-1264			

PSE&G allocates the bus costs based on peak demand because the bus is designed and installed to serve peak loads.[109]

PSE&G's distribution system is an integrated network. The equipment included in the facilities charge does not have the capability of delivering power to the generating stations without the use of other equipment. For example, additional equipment is needed to deliver power to the distribution bus. Other equipment is needed to maintain system reliability and control. Basing distribution delivery rates solely on the costs of the closest electrical bus and the circuit from the bus to the plant site is questionable.

The FERC regulates station power arrangements that do not use local distribution facilities. Generating plants can obtain station power directly from the transmission grid over their transmission interconnection when all of the units at the plant are off-line. The FERC has well-established policies for the provision of station power over transmission interconnection facilities.[110]

The withdrawal of station power from the transmission grid is reported as negative net generation. The FERC allows generators to net their hourly positive and negative net generation over a calendar month. If net generation is positive for the month, the generator is deemed to have self-supplied all of the station power it obtained from the transmission grid.

During hours with positive net generation, the generator receives the hourly spot market energy price for its net generation. During hours with negative net generation, the generator pays the hourly energy price. In substance, the generator buys its station power from the energy spot market during hours when the plant is not operating.

[109] Response to Discovery, OC-1263

[110] Order on Petitions for Declaratory Order, FERC Docket ER00-3513-000, March 14, 2001 (PJM). Also, Order Granting Rehearing, FERC Docket ER05-849-002, October 17, 2008 (CAISO).

Other rules apply when the plant's monthly net generation is negative.[111] Those rules are not explained in this report because they rarely apply to the PS Power generating stations located within PSE&G's zone.[112]

The FERC has repeatedly stated that it does not set rates for the delivery of station power over local distribution facilities. According to FERC, the appropriate level of charges for the use of local distribution facilities to deliver station power is a state matter.[113]

FERC determined a "state may approve whatever rate level it deems appropriate, including the recovery of stranded costs, when a utility...is using local distribution facilities for the delivery of station power.[114] Similarly, FERC stated "Utilities may still recover stranded costs...from merchant generators that actually take delivery (of station power) over local distribution facilities."[115]

PSE&G agrees that the facility charges are BPU jurisdictional rates.[116]

The FC deliveries occur at a voltage of 26kv. Distribution deliveries at that voltage are subject to PSE&G's High Tension Service (HTS) rate schedule for sub-transmission voltages.

The HTS rate schedule is applicable to delivery service for general purposes at subtransmission and high voltages. HTS customers may either purchase electric supply from a Third Party Retail Supplier or from PSE&G's BGS default service.[117]

Overland estimated the charges for the FC deliveries would have been $4.7 million under the HTS rate schedule in 2009. The estimate does not include any electric supply charges.[118] The estimate includes the Societal Benefits Charge (SBC), Securitization Transition Charge (STC), and Non-Utility Generation Charge (NGC).

The facilities charges totaled $397,448 in 2009. That represents a discount of approximately 90 percent from the HTS rate. The FC delivery rates averaged less than one-third of a cent per kwh in 2009. The estimated HTS charges average 3.3 cents per kwh.

[111] PJM Operating Agreement, Section 1.7.10 (D) and PJM Manual 28, Section 12. When a plant with negative monthly net generation is owned by a company with more than one station, the plants with positive generation can provide "remote self-supply" of station power to the plants with negative generation. PJM charges non-firm transmission charges for the remote self-supply. Stations can also purchase station power from third parties.

[112] The PS Power generating plants in the PSE&G zone almost always have positive monthly net generation, with the exception of National Park (Response to Discovery, OC-1077). National Park buys 100 percent of its station power over a retail feed.

[113] FERC Order Denying Rehearing, Docket No. EL01-50-004, May 10, 2004 (Keystone), page 19.

[114] FERC Order Denying Rehearing, Docket No. EL01-50-004, May 10, 2004 (Keystone), page 19.

[115] FERC Order, Docket No. ER05-849-002, October 17, 2008 (CAISO), page 15.

[116] Response to Discovery, OC-1265.

[117] PSE&G Electric Tariffs, Sheet No. 155.

[118] The estimate reflects the delivery charges that would be incurred by a customer who purchases electric supply from a third party retail supplier. The estimate is based on 2009 MWH deliveries and the station power peak demand used in the common plant allocator.

Recommendation: PSE&G should charge tariff rates for station power delivered over local distribution facilities.

PSE&G admits that the delivery of station power over local distribution facilities is a BPU jurisdictional service. According to PSE&G, PS Power self-supplies the energy that is delivered over the FC facilities. As a result, a retail sale of electricity has not occurred. According to PSE&G, the SBC charge does not apply because "the energy utilized as Station Power is not BPU jurisdictional."[119]

The HTS rate schedule applies to delivery service, not sales of electricity. PSE&G delivers the power over its local distribution facilities at the required voltage. Therefore, the HTS rate schedule should apply.

PS Power does not purchase the energy from a third party retail supplier or from PSE&G's BGS default supply. Instead, the energy is accounted for as a reduction in PS Power's net generation and energy sales to PJM. That energy accounting does not change the fact that the power is delivered to PS Power over local distribution facilities.

The appropriate rate for the delivery of station service over distribution facilities is a matter for the BPU to decide. FERC has explicitly stated that utilities can include charges for stranded cost recovery in delivery rates for station power if local distribution facilities are used to deliver the power. PSE&G's position that the HTS rate schedule and the SBC, STC and NGC do not apply to the FC deliveries is questionable. PSE&G should explain the basis for those positions in its response to this report.

If PSE&G concludes that the HTS tariff does not apply, it should propose a reasonable retail rate schedule for the deliveries. If PSE&G continues to charge rates that are significantly below the HTS delivery rates, it should state the basis for the lower rates and provide verifiable cost support.

PS Power could by-pass the distribution system and obtain its station power directly through the transmission interconnections for the plants. If PSE&G believes discounts are required to maximize the contribution to fixed distribution costs obtained from PS Power, it should present estimates of PS Power's by-pass costs and explain its discounting strategy.

PSE&G Sales of Non-Power Goods and Services to PS Power

This section addresses non-power goods and services transactions between PSE&G and PS Power. The FERC has transfer pricing rules for non-power goods and services. Those rules are described in Chapter 16.

PSE&G charged $22 million to PS Power in 2009 for non-power goods and services. Those charges are summarized below.

[119] Response to Discovery, OC-1265

Table 17-12 - PSE&G Charges to PS Power, Non-Power Goods and Services By Category

PSE&G Charges to PS Power Non-Power Goods and Services By Category 2009 - Dollars in Thousands	
Category	**Amount**
Electric System Maintenance and Construction	6,950
Joint Transmission Line O&M Reimbursement	5,476
Non-Qualified Pension and Other Post-Retirement Benefits	4,277
New Jersey Radiation Emergency Response	2,664
Rent	734
Fleet	630
Energy Management System (EMS)	543
Workers Compensation and Benefit Reimbursement	395
General Support	334
PSEG Corporate Real Estate Tax Allocation True-up	188
Electric Reliability Organization Support	183
Phone Operators	71
Other (net)	26
Total	22,471
Source: Response to Discovery, OC-59 and OC-738. Adjusted to net some amounts billed by PSE&G to Power that are offset by billings from PS Power to PSE&G.	

PSE&G makes all of the payments to the PSEG Enterprise Non-Qualified Pension and Other Post-Retirement Employee Benefit plans. PSE&G bills PS Power and the other PSEG subsidiaries for their share of the payments based on allocations provided by the plan actuaries. PSE&G makes these payments because it is the "legacy company."[120] PSE&G billed $4.3 million to PS Power for its share of the Non-Qualified Pension and OPEB costs in 2009.

The EMS charges are discussed in Chapter 16. The Utility's Fleet Department maintains and repairs vehicles assigned to PS Power. The fleet charges include gasoline, snow plowing and facilities charges for PSE&G's Mulberry Street Garage.[121]

The PSEG Service Company pays the real estate taxes for all of PSEG's subsidiaries and bills the subsidiaries for reimbursement. The allocation of total real estate taxes between subsidiaries is trued-up in December based on actual tax bills. PSE&G charged $187,825 to PS Power as part of the annual true-up process.[122]

The PSEG phone system has three operators. The operators are PSE&G employees. Their costs are allocated to PS Power using the Modified Massachusetts formula.[123]

[120] Response to Discovery, OC-874
[121] Response to Discovery, OC-870
[122] Response to Discovery, OC-1423
[123] Response to Discovery, OC-870

PSE&G Equipment Maintenance Charges to PS Power

The following table shows the equipment maintenance and construction services that PSE&G provided to PS Power in 2009.

Table 17-13 - PSE&G Equipment Maintenance and Construction Charges to PS Power

PSE&G Equipment Maintenance And Construction Charges to PS Power Dollars in Thousands	
Description	**Amount**
Bergen	11
Burlington	1
Hope Creek Relay Work	1,108
Hope Creek Outage Support	492
Hope Creek Capacitor Upgrade	99
Hope Creek Other	30
Hudson Facilities Relocation	3,446
Hudson Other	21
Kearny	6
Linden Outage	29
Mercer	4
Salem Relay Work	984
Salem Outage Support	304
Salem Remote Terminal Unit	50
Sewaren	1
Lab Analysis and Support	87
Central Pipe Stock	96
Other - Facility Not Identified	181
Total	6,950
Source: Response to Discovery, OC-59 and OC-738.	

PSE&G charged three types of equipment maintenance and construction services to PS Power in 2009:

- Maintenance of utility owned interconnection attachment facilities;
- Maintenance of PS Power owned equipment, and.
- Relocation of utility-owned facilities for the Hudson Back End Technology (BET) project.

PSE&G charged $321,354 in Attachment Facility maintenance costs to PS Power in 2009, as shown in the following table.

Table 17-14 - PSE&G Attachment Facility Charges to PS Power

PSE&G Attachment Facility Charges to PS Power 2009 - Dollars in Thousands	
Plant	**Amount**
Bergen	21
Burlington	12
Edison	12
Essex	66
Hudson	32
Kearny	48
Linden	82
Mercer	48
Total	321
Source: Response to Discovery, OC-970	

The Attachment Facility maintenance charges are presumably included in the $6.95 million of charges shown above.

The maintenance of PS Power owned equipment is performed at PS Power's request. PS Power meets with PSE&G's Electric Division Management on a recurring basis to review Power's planned work and schedule. Routine maintenance and planned outages are reviewed during those meetings. Power identifies the work it would like PSE&G to perform. PSE&G's Division Management identifies the resources needed to complete the work. PS Power provides the necessary accounting instructions. PSE&G employees perform the work and charge their costs to work orders that charge to PS Power.[124]

PSE&G performs relay work on facilities that were transferred to PS Power in 2000. PSE&G performs maintenance on PS Power equipment in switching stations where the PS Power equipment is located physically and electrically close to PSE&G facilities. PS Power has the right to do the work itself, but prefers to have PSE&G do the work because utility personnel are familiar with the equipment and have the needed skills. PSE&G prefers to have utility employees managing and performing the work to minimize the risk of errors impacting utility operations.[125]

The Hope Creek and Salem Relay charges reflect the costs of performing maintenance and testing of relay facilities owned by PS Power that are located in the Hope Creek and Salem switching stations.[126] The Hope Creek and Salem relay work charges consist almost entirely of labor and overheads. The Hope Creek and Salem outage work consists of work on relay equipment owned by PS Power and other support during refueling outages.[127]

[124] Response to Discovery, OC-742.
[125] Response to Discovery, OC-739.
[126] Response to Discovery, OC-1240 and OC-1420.
[127] Response to Discovery, OC-1249.

The Hope Creek and Salem relay work is performed by PSE&G's Southern Division Relay Department. PS Power provides PSE&G with work orders and PSE&G performs the work. PS Power monitors and evaluates the work and compares actual and planned costs.[128]

The Hudson facilities relocation project was required by the installation of new pollution control equipment at the plant. PSE&G relocated an overhead transmission line in the Hudson Switchyard and two feeds to step-down transformers.[129] PS Power contacted PSE&G's Transmission Engineering Group to make arrangements for the work. PSE&G retained an outside engineering firm for the design work, and an outside construction contractor for the construction work. Approximately 75 percent of the costs are for outside contractors. PSE&G charged $418,000 in labor and overheads to the project in 2009.[130]

PSE&G Charges to PS Power - Internal Controls

From an internal control perspective, PSE&G treats the maintenance and construction work it performs for PS Power the same as utility work. PSE&G does not implement any controls beyond those that apply to the work it performs on utility property.

PS Power requests the work through telephone contacts and emails. PSE&G and PS Power do not prepare a written scope of work or cost estimate. PS Power provides PSE&G with a job number for charging purposes.

The charges are based on cost. The costs are accumulated in SAP. Approvals of the SAP entries are governed by PSE&G's normal corporate requirements for review and approval in SAP.[131]

As the client department, PS Power is responsible for reviewing the charges for reasonableness and completeness.[132] The charges are settled through the inter-company settlement process without invoices.[133]

Management reporting is an important aspect of internal controls. Management reports on affiliate charges should summarize the charges in meaningful categories so that management is aware of the nature and level of services being provided. Management reporting provides a basis for identifying missing or erroneous charges. Management reporting also facilitates regulatory audits by providing information in an accessible manner.

PSE&G does not prepare any monthly reports that summarize its charges to PS Power. The only monthly report for the charges is the intercompany billing summary schedule.[134] That report lists the charges for the current month by source system. The line item descriptions do not provide meaningful information

[128] Response to Discovery, OC-1420.
[129] Response to Discovery, OC-742.
[130] Response to Discovery, OC-1249.
[131] Response to Discovery, OC-1259 and OC-1260.
[132] Response to Discovery, OC-1420 and OC-742.
[133] Response to Discovery, OC-1260 and OC-870.
[134] Response to Discovery, OC-871.

concerning the nature of most of the charges. The description provided for many charges is "FI - reconciliation posting CO." Many other charges are described as "E-Plt Mat & Oper Suppl."

The report does not summarize charges into meaningful categories. The report does not show prior month charges or year-to-date costs, nor does it compare recorded charges to planned costs. PSE&G's management reports for utility charges to PS Power are inadequate.

In its initial set of audit discovery, Overland requested a breakdown of PSE&G's charges to PS Power for 2007, 2008 and 2009 by transaction type. PSE&G provided data for a single month and requested a reduction in the scope of the request because of the effort required to produce the data. Overland reduced its request to monthly data for calendar year 2009. PSE&G indicated that providing the 2009 data would be a time consuming and data intensive process that would require about eight to ten weeks.[135]

PSE&G provided the last of the 2009 data nine weeks later. PSE&G broke the charges into 20 to 25 line items for each month. PSE&G's inability to provide basic support for the charges in a timely fashion demonstrates the lack of adequate management reporting for its charges to PS Power.

PSE&G charged PS Power $6.3 million for the following in 2009.

- Hudson Switchyard - BET Project.
- Hope Creek Relays and Outage Support.
- Salem Relays and Outage Support.

Overland requested the work initiation, authorization, and billing documents pertaining to those services for the work done in February 2009, including the service request, work orders, scope descriptions, cost estimates, evidence of required approvals, invoices and detail of charges. PSE&G provided some cost breakdown information and indicated the other requested documents do not exist.[136]

PSE&G indicated that work orders existed on-line in SAP and could be viewed on-line at PSE&G's office. Overland requested and attended an on-line demonstration, but no work orders were made available on-line or otherwise.

A subsequent discovery request tied to specific work order numbers for Hope Creek Relay work produced a narrative response but no actual documentation.[137] The response indicated PS Nuclear "provides their work management work orders to the PSE&G Southern Division Relay Department for execution." Overland submitted a follow-up request for the work management work orders that PS Nuclear provided to PSE&G for Hope Creek Relay work in 2009. PSE&G provided two examples of PS

[135] Response to Discovery, OC-738.
[136] Response to Discovery, OC-742 and OC-945.
[137] Response to Discovery, OC-1420.

Nuclear "work packages" for specific relay testing procedures. The two examples covered 40 of the 4,921 hours charged to Hope Creek relay work in 2009.[138]

PSE&G provided only two examples because the work packages are stored as scanned documents in PS Nuclear's document management system and are difficult to retrieve. According to PSE&G, printing each work package takes two hours.[139]

The work packages included:[140]

- "Work order shop papers" notifying the Southern Division Relay Department of the scheduling window for performing the procedure;
- A lengthy procedures checklist documenting the completion of the test; and
- A data sheet listing the equipment tested and the names of the relay technicians that did the work.

The work order shop papers are one page forms that list the procedure to be completed. They do not include any cost or labor hour estimates. The work order shop papers notify PSE&G that the work needs to be done without any indication of who authorized the work.

Each step in the procedures checklist is initialed by the relay technician to signify completion. The one page data sheet is signed by the maintenance supervisor to verify completion of the work.

PSE&G charges third parties for relocating utility services when the relocation is done to accommodate the third party. Third party work requires:[141]

- A signed agreement with the customer;
- A documented scope of work;
- A cost estimate prior to construction;
- Change orders when costs significantly exceed the estimate; and
- Paper invoices.

None of those controls are required when PSE&G does work for PS Power. PSE&G's Third-Party Billing Department reviews charges to third parties for completeness.[142] PSE&G does not have a similar review for PSE&G charges to PS Power.[143]

When charges to PS Power are understated, the unbilled costs default to utility accounts. The key control over this risk is comparing the project cost estimate to the amounts charged to PS Power. If the groups doing the work fail to correctly charge their costs to PS Power, that should show up as a

[138] Response to Discovery, OC-1464.
[139] Response to Discovery, OC-1464.
[140] Response to Discovery, OC-1464.
[141] Response to Discovery, OC-1259.
[142] Response to Discovery, OC-1259, page 9.
[143] Response to Discovery, OC-873.

difference between the initial cost estimate and the recorded charges. PSE&G does not prepare cost estimates. As a result, it does not have any basis for identifying missing charges.

The costs are charged to PS Power client departments who review the charges for reasonableness.[144] PS Power does not have an incentive to correct undercharges from PSE&G and should not be relied upon to identify missing charges.

Recommendation: PSE&G should improve its internal controls over charges to PS Power.
PSE&G should implement the following improvements in its internal controls over charges to PS Power:

- Scope descriptions and cost estimates for all projects and services that are expected to have a cost annual cost of over $100,000. Annual budgets for recurring services.
- Change orders explaining the reasons for significant cost increases over the initial estimate.
- Centralized review of the charges by the PSE&G's Third Party Billing Department for completeness and reasonableness upon completion of the project, or monthly reviews for recurring services.
- Estimate versus recorded cost comparisons with explanations for variances,
- A monthly management report showing the current month and year-to-date recorded and planned charges by project and service category, with explanations for significant variances between planned and recorded charges.

The monthly management report should be provided to PSE&G's Vice President - Electric Operations and its Electric Operations Division Managers. They should be tasked with reviewing the charges for completeness and reasonableness.

Services Agreement

PSE&G provides non-power services to Power under the 1994 Services Agreement.[145] The 1994 Service Agreement predates the creation of PS Power and the PSEG Services Corporation. The 1994 Agreement also predates the implementation of SAP.

The parties to the 1994 agreement are PSE&G, Pubic Service Enterprise Group and Enterprise Diversified Holdings, Incorporated. Schedule A to the agreement lists the services that PSE&G provides to Enterprise. The one page list of services is seriously outdated. All of the listed services are corporate administrative services currently provided by the PSEG Services Corporation. Article II describes the determination of cost-based charges. The description pre-dates SAP and is no longer accurate.

[144] Response to Discovery, OC-1420 and OC-742.
[145] Response to Discovery, OC-735 and OC-740.

The 1994 Service Agreement was amended in 1999. The brief amendment:

- Substitutes the phrase "PSEG and its Subsidiaries" for the phrase "Enterprise and EDHI" wherever it appears in the 1994 agreement.

- Indicates PSEG and its Subsidiaries shall perform services for PSE&G at cost and in a manner consistent with BPU requirements.

There have been no other amendments to the Services Agreement.

Recommendation: PSE&G should enter into a Services Agreement with PS Power.

The amended Services Agreement does not accurately describe either the services currently provided or the charging methodology. Many of the provisions of the Services Agreement are no longer applicable. PSE&G should terminate the Services Agreement and enter into a new agreement with PS Power that covers the non-power services they provide to each other.

PECO Deposit Transfer

PSE&G and four other utilities are participants in the Lower Delaware Valley Transmission System (LDV). The system was constructed to deliver power from the Peach Bottom and Salem nuclear units to the owners of those units. PECO Energy is one of the other four participants.

PSE&G bills PECO Energy for its share of the LDV's charges each month. PECO wires the payment to a PS Power bank account. The payments should be wired to a PSE&G bank account, not a PS Power bank account. Despite numerous requests from PSE&G, PECO continues the wire the funds to the wrong bank account.[146] PSE&G collects the funds from PS Power through the intercompany billing process. The charges totaled $5.5 million in 2009.

Recommendation: PSE&G should require PECO to stop depositing utility funds in a PS Power bank account.

Utility funds should not be wired to a PS Power bank account. PSE&G should require PECO to wire its LDV payments to a PSE&G bank account.

The current arrangement is also inappropriate, as it effectively results in PSE&G extending credit to PS Power and complicates the review of intercompany billings by creating large unnecessary transactions.[147]

[146] Response to Discovery, OC-874

[147] In its comments on this report, PSE&G states it has taken action to ensure that payments are wired to a PSE&G bank account.

Radiation Response Fund

The New Jersey Radiation Response fund assesses a fee to operators of nuclear power plants to defray the cost of local, county and state agencies in discharging their responsibilities under the Radiation Accident Response Act.[148]

PSE&G pays the fee and obtains reimbursement from PS Power through the intercompany billing process. PSE&G pays the fee because "the State of New Jersey was set up as a vendor of the utility."

Recommendation: The New Jersey Radiation Response Fund fee should be paid directly by PS Power.

The fee is an obligation of PS Power, not PSE&G. Therefore, PS Power should make the payment to the state. This arrangement also results in PSE&G effectively extending credit to PS Power and makes the review of intercompany billing more difficult by creating large unnecessary transactions.

In its comments on this report, PSE&G states that New Jersey law defines the Utility as the operator of the nuclear facilities that are subject to the New Jersey Radiation Fund. PSE&G adds that the New Jersey Department of Treasury has considered and rejected PSE&G's request to transfer that obligation to PSEG Nuclear, based upon its conclusion that PSEG Nuclear LLC is not considered an operator under *N.J.S.A.* 26:2D-39(f).

Rent

PSE&G charges rent to PS Power for the following property:

- Office and warehouse space at PSE&G's 4000 Hadley Road facility in South Plainfield.
- Construction laydown areas at PSE&G's West End Gas Works in Jersey City.

The annual rent for the Hadley Road Facility is approximately $383,000 a year. The annual rent for the West End Gas Works is approximately $300,720 a year. In addition, PSE&G charges PSE&G Power for its proportionate share of real estate taxes and common area maintenance costs.[149]

The base rent for the Hadley Road facility is shown below by type of space.

[148] Response to Discovery, OC-1250
[149] Response to Discovery, OC-741

Table 17-15 - PSE&G Rent Charges to PS Power, Hadley Road Facility by Type of Space

PSE&G Rent Charges to PS Power Hadley Road Facility By Type of Space			
Type	Square Feet	Rate	Annual Rent
Office	17,586	18.5	325,341
Warehouse	11,555	5	57,775
Total	29,141	13.1	383,116
Source: Response to Discovery, OC-741.			

PSE&G rented the Hadley Road space to PS Power without a written lease agreement prior to August 2010. PSE&G and PS Power executed a written lease agreement on August 25, 2010. [150]

PSE&G reviewed rental market prices in 2010 to determine if the Hadley Road rental rates were appropriate. PSE&G obtained market data for 18 buildings from its outside real estate brokerage agency, Colliers in June 2010. PSE&G concluded the data supported a market price of $13.29 for office space and a market price of $5.32 for warehouse space.[151] Those rates produce an annual rent of $295,164. PSE&G elected to maintain the rent at its prior level of $383,116. The Hadley Road rental rates appear to be reasonable.

PSE&G entered into a rental agreement with PS Power for The West End Gas Works in December 2007. The rental covers three construction laydown areas totaling 8.7 acres. PS Power needed the laydown areas for its Hudson Back End Technology construction project. The annual rent is calculated by multiplying the land's property tax valuation times a carrying charge rate of 8 percent. The annual rent is $300,720 or $34,565 per acre. The term of the agreement is unlimited but can be terminated by either party on 90 days notice.[152] The West End Gas Work lease terms appear to be reasonable.

PSE&G Purchases of Non-Power Goods and Services From PS Power

PS Power billed approximately $16 million of non-power goods and services to PSE&G in 2009. The following table summarizes PS Power's billings to PSE&G.

[150] Response to Discovery, OC-741, Supplemental Response
[151] Response to Discovery, OC-951
[152] Response to Discovery, OC-741

Table 17-16 - PS Power Charges to PSE&G, Non-Power Goods and Services by Category

PS Power Charges to PSE&G Non-Power Goods and Services By Category 2009 - Dollars in Thousands	
Category	**Amount**
Electric System Maintenance	14,361
Building HVAC Services	670
Real Estate Taxes for Easements on PS Power Land	387
Workers Compensation and Medicare Subsidy	378
Reclassifications	269
General Support	93
Total	16,158

Source: Response to Discovery, OC-58 and OC-733. Adjusted to net some amounts billed by PSE&G to Power that are offset by billings from PS Power to PSE&G.

PSE&G has utility easements on the land owned by PS Power for each of its generating stations. The easements are for electric lines, gas lines and switchyards. PS Power allocates a portion of the real estate taxes for its plants to PSE&G's easements based on the acreage of the easement areas. PS Power charged PSE&G $386,972 for easement real estate taxes in 2009.[153]

PS Power Building HVAC Charges to PSE&G

PS Power provides heating, ventilating and air conditioning (HVAC) services for PSE&G facilities, including the headquarters building, customer operations offices and control houses and substations and switchyards.[154] The HVAC services are provided by PS Power's System Maintenance Division (SMD).[155]

The scope of services includes maintenance and repair of:

- Air conditioning systems;
- Large electric motor powered belt driven whole building ventilation systems;
- Large natural gas boiler heating systems;
- Direct fired gas space heaters;
- Heat pumps, and
- Resistence heating units.

The work is initiated by telephone contact. The services are billed at cost. The cost of providing the services is tracked in SAP. PSE&G does not track the costs by building. The total billings in 2009 were $670,263.[156]

[153] Response to Discovery, OC-736
[154] Response to Discovery, OC-1253
[155] Response to Discovery, OC-1461
[156] Response to Discovery, OC-59 and OC-733

PSE&G transferred its facilities support personnel to PS Power as part of generation deregulation. PSE&G purchases the services from PS Power because of the facility support group's "outstanding capabilities, IBEW affiliation, the ability to work without safety oversight, the ability to access NERC/FERC critical facilities without a security escort and because they have been trained and background checked."[157]

PS Power Electric System Maintenance Charges to PSE&G

PS Power charged $14 million to PSE&G for electric system maintenance in 2009. The following table shows the charges by category.

Table 17-17 - PS Power Charges to PSE&G, Distribution and Transmission System Maintenance

PS Power Charges to PSE&G Distribution and Transmission System Maintenance 2009 - Dollars in Thousands	
Category	**Amount**
Substations and Switchyards	3,392
Overhead Lines and equipment	2,429
Transformers	2,405
Infrared Inspections (Substations and Switchyards)	1,740
Underground Lines	1,667
Maplewood Lab Support	1,024
Equipment Testing	804
Remote Terminal Units	206
Relays	146
Breakers	105
Other	443
Total	14,361
Source: Response to Discovery, OC-58 and OC-733.	

PSE&G's 2009 FERC Form 1 report provides the following breakdown of the non-power services provided to the utility by PS Power.

[157] Response to Discovery, OC-1253

Table 17-18 - Non-Power Goods and Services, Provided to PSE&G by PS Power

Non-Power Goods and Services Provided to PSE&G by PS Power Per PSE&G 2009 FERC Form 1 Report 2009 - Dollars in Thousands	
Description	**Amount**
Maplewood Testing Services	6.8
System Maintenance Department	1.7
Central Maintenance Shop	1.5
Total	10
Source: PSE&G 2009 FERC Form 1, page 429.1	

The FERC Form 1 total is $4.4 million lower than the amounts PSE&G reported in its discovery responses. The reasons for that differences are not known.

PS Power's Maplewood Testing Services (MTS) is commonly referred to as the Maplewood Lab. MTS has 117 employees and is located in Maplewood New Jersey.[158] PSE&G transferred MTS to the PSEG Services Corporation as part of electric industry restructuring. MTS was transferred to PS Power effective January 1, 2009.[159]

MTS provides specialized testing services including material condition analysis, failure diagnosis, transformer oil analysis and infrared inspections. MTS is PSE&G's sole source for those services. PSE&G does not perform any of the services internally. The maintenance and testing services provided by MTS cover all of the equipment in PSE&G's distribution and transmission systems.[160]

PS Power's Central Maintenance Shop (CMS) is a full capability machine and parts fabrication shop. CMS fabricates specialty equipment components that are no longer available from the manufacturer or are required quickly in an emergency.[161]

PSE&G uses PS Power's SMD as a force multiplier for its Electric Divisions. During 2009, the SMD augmented PSE&G personnel on the installation of High Efficiency Streetlights. That work was done as part of BPU approved Capital Economic Stimulus program. SMD provided the second person on a PSE&G street light installation crew, effectively doubling the capabilities of each Electric Division's Street Light Department.[162]

Overland requested monthly detail for 2009 by order number for the major categories of service. PSE&G was only able to provide five months of detail "due to the complexity, formatting and verification

[158] Response to Discovery, OC-734.
[159] Response to Discovery, OC-1481.
[160] Response to Discovery, OC-734.
[161] Response to Discovery, OC-1256.
[162] Response to Discovery, OC-1255.

associated with gathering the data."[163] The following descriptions are based on the incomplete information provided by PSE&G.

The $3.4 million of substation and switchyard charges were primarily for testing services provided by MTS, including equipment calibration and integrity tests on circuit breakers, power transformers, current transformers, capacitivity coupled voltage transformers, batteries and remote terminal units (RTUs). The RTUs are used by the EMS system. There are also some minor charges from the CMS.[164] PSE&G owned 42 switching stations and 246 substations as of December 2009.[165]

The substation and switchyard charges included 155 SAP orders during the first five months of 2009 totaling $949,203. The largest order during that period was $113,627 for a substation reinforcement. The next largest order was a $64,625 blanket inside plant order for the Central Division.[166]

The $2.4 million in overhead line charges included the street lighting installation work performed by the SMD, and infrared inspections of overhead circuits performed by MTS. During the first five months of 2009, infrared inspection costs accounted for 91 percent of the charges.[167]

The $2.4 million in transformer charges are primarily for testing services provided by MTS, including insulating oil, transformer turn ratio, Doble, Hi pot, frequency response analysis, failure analysis and noise testing. The charges also included minor amounts from the CMS for fabrication of gears and linkage components for transformer tap changers, specialty welding and customer sheet metal fabrication.

During the first five months of 2009, the largest charge was $340,807 for a transformer modification. Oil testing accounted for approximately 34 percent of the total transformer charges during that period.[168]

The $1.74 million of infrared inspection charges were for equipment located in the substation and switching stations, including transformers. Infrared inspections involve the use of a special "camera" to detect overheating on lines and equipment. Infrared inspections are conducted on a regular schedule by MTS as part of routine preventative maintenance.[169]

The $1.7 million in underground line costs are primarily for infrared inspections and insulating oil tests performed by MTS.[170]

PSE&G has over 10,000 devices in its preventative maintenance plan. Each device is maintained on an established schedule. As a result, the charges from MTS are very stable from year-to-year.[171] The 2010

[163] Response to Discovery, OC-1254, OC-1255 and OC-1256.
[164] Response to Discovery, OC-1254.
[165] PSEG 2009 SEC 10-K Report, page 41.
[166] Response to Discovery, OC-1254.
[167] Response to Discovery, OC-1255.
[168] Response to Discovery, OC-1256.
[169] Response to Discovery, OC-734
[170] Response to Discovery, OC-1258
[171] Response to Discovery, OC-1208

Budget for MTS charges to the utility was $7.0 million. The MTS budget is consistent with the $6.8 million MTS charges reported in PSE&G's FERC Form 1.

PS Power charged PSE&G $14.4 million for equipment maintenance and testing in 2009. According to PSE&G, the only PS Power organizations providing those services were MTS, CMS and SMD. PSE&G's FERC Form 1 indicates MTS, SMD and CMS only charged $10.0 million to PSE&G in 2009, and that presumably includes $670,000 in charges from SMD for HVAC services. The disparities between the charges reported in PSE&G's data responses and the FERC Form 1 data implies that PSE&G's descriptions of the services are incomplete.

Recommendation: PSE&G should review its purchases from PS Power for compliance with the BPU's Holding Company Rules.

The BPU's Holding Company Rules prohibit PSE&G from purchasing any services from affiliates that PSE&G can obtain "on more advantageous terms" by other means. Other means may include doing the work internally or purchasing the service from non-affiliated vendors.[172] The BPU's Holding Company Rules are described in Chapter 16.

The rules require PSE&G to review its purchases from affiliates every three years for compliance with the most advantageous terms requirement. The initial review is required by April 2012.

PSE&G should review the advantages and disadvantages of purchasing services from MTS, SMD and CMS compared to the alternatives of performing the work internally or purchasing the services from non-affiliated vendors. The study should consider the option of transferring some MTS employees back to the utility. The study should also explain why MTS was transferred from PSEG Services Corporation to PS Power in 2009.

PSE&G cites the following reasons for purchasing services from MTS.[173]

- Convenient to work with since purchase orders, billing and invoices are not required;
- Work quality has always been excellent;
- Staffed with highly qualified test engineers;
- Speciality support personnel with IBEW affiliation, security checks and safety training;
- Unique knowledge of required maintenance for highly specialized electrical distribution and transmission equipment;
- Experience with all of PSE&G's testing needs and equipment;

[172] N.J.A.C. 14:4-4.A.5 (b)
[173] Response to Discovery, OC-734, OC-1254, OC-1255, OC-1256 and OC-1267

- Available on a 24 hour a day basis for emergency work;
- Ability to work without oversight;
- Ability to access NERC/FERC critical facilities without a security escort;
- MTS attends PSE&G's system update meetings;
- MTS is familiar with PSE&G's work sites and participates in planning and scheduling activities; and
- Sales taxes are not applied to MTS charges to PSE&G.

MTS has provided testing services to PSE&G for 80 years. MTS has lifetime test data for all of the existing and retired equipment in PSE&G's distribution and transmission systems. The historical test data facilitates the evaluation of new test results.[174]

The extent to which transferring all of PSE&G's utility test data to PS Power provides PS Power with a competitive advantage in generation and interconnection planning is unknown.[175]

SMD has a full staff of highly qualified IBEW, safety trained, background checked facilities support personnel that service all of PSE&G's HVAC systems. PSE&G utilizes SMD for HVAC services and as a force multiplier for its Electric Divisions because of its outstanding capabilities, IBEW affiliation, ability to work without oversight and ability to access NERC/FERC critical facilities without a security escort.[176]

PSE&G utilizes the CMS machine and parts fabrication facility because it is convenient to work with, since purchase orders, billings and invoices are not required.[177] According to PSE&G the work quality has always been excellent. CMS services are provided by union personnel with the appropriate affiliation, necessary security clearances and safety training.[178]

According to PSE&G, the cost based charges from MTS, CMS and SMD are always lower than a "for profit" union contractors charges for similar work.[179]

PSE&G has only prepared one study of the market price of the services provided by PS Power in the past four years.[180] That study was prepared in 2008 and compared MTS fully loaded average labor costs to hourly rates charged by testing vendors. The study also compared MTS charges to the charges from one

[174] Response to Discovery, OC-734
[175] Performing the testing presumably requires manufacturers information pertaining the equipment. MTS presumably has a complete inventory of the equipment installed in PSE&G's distribution and transmission systems.

[176] Response to Discovery, OC-1253 and OC-1255.
[177] Response to Discovery, OC-1255.
[178] Response to Discovery, OC-1254.
[179] Response to Discovery, OC-1257.
[180] Response to Discovery, OC-1267.

identified vendor for eleven selected mechanical division procedures.[181] The study consists of ten pages of tables without any narrative discussion. The tables characterize the comparisons as benchmarking.

The tables indicate that MTS's charges are lower than the prices charged by outside vendors. The following table shows the rankings for the MTS labor rates:

Table 17-19 - MTS Labor Rate Comparison, 2008 Benchmarking Study

MTS Labor Rate Comparison 2008 Benchmarking Study Rank of 1 is Lowest Cost		
Type of Service	**Number Surveyed**	**MTS Rank**
Electrical	14	1
Mechanical	14	2
Chemical	6	4
Source: Response to Discovery, OC-1267		

The comparisons for selected procedures include several procedures that are only applicable to generating plants. The scope of the benchmarking exceeds the scope of the services provided to PSE&G.[182]

The tables indicate a total MTS budget of $21.8 million. PSE&G's FERC Form 1 indicates PSE&G purchased $6.8 million in services from MTS in 2009.

The FERC Affiliate Restrictions allow the sharing of field and maintenance employees.[183] The benefits of purchasing services from MTS, CMS and SMD cited by PSE&G are plausible. The rationales for using SMD as a force multiplier and for purchasing machine shop services from CMS appear to be sound. The rationales for purchasing testing services from MTS and HVAC services from SMD are less convincing. Transferring some MTS and SMD employee groups back to the utility and performing the work internally may provide the same benefits and avoid affiliate relations issues.

The BPU Holding Company Rules require a review of the services by April 2012. That review provides an opportunity to assess whether the current structure is optimal from the perspective of ratepayers. PSE&G should prepare a study of the advantages and disadvantages of purchasing services from PS Power's MTS, SMD and CMS compared to the alternatives of performing the work internally or purchasing the services from non-affiliated vendors.

[181] The identified vendor varies from procedure to procedure.
[182] The study may have been prepared for labor negotiations.
[183] 18 CFR, Section 35.39. The FERC Affiliate Restrictions are discussed in Chapter 16.

Internal Controls

From an internal control perspective PSE&G treats the charges from PS Power the same as internal utility charges. PSE&G does not implement any controls beyond those that apply to work it performs internally on utility property.

PSE&G purchases from PS Power not covered by the controls that PSE&G places on purchases from outside vendors. From that perspective, charges from PS Power are covered by substantially weaker controls than other utility transactions.

The work consists of two types: (1) routine work included in a planned inspection and maintenance program; and (2) work performed upon a specific request. The planned routine maintenance is included in the client department's annual budget. The utility client is responsible for reviewing the charges each month to ensure they are in accordance with the planned amounts.[184]

Planned and budgeted activity represents the bulk of the charges. The budgets are generally based on the charges in prior years. Due to the recurring nature of the work, a formal process is not required for the MTS budget of charges to the utility.[185]

Specific service requests are made through telephone contacts and emails.[186] PSE&G and PS Power do not prepare a written scope of work or cost estimate for smaller specific requests. PS Power provides an estimated cost to the client department for larger specific projects.[187]

PSE&G provides PS Power with utility SAP order numbers for the work. The charges are based on cost. The costs are accumulated in SAP. SAP time keeping prevents double billing and provides transparency.[188]

Approvals of the SAP entries are governed by PS Power's normal corporate requirements for review and approval in SAP. The charges are settled through the inter-company settlement process without invoices.

Most of the work provided by MTS, CMS and SMD is well understood by the utility client and is so routine that scope documents are not required. Specific approvals are not required because routine services are budgeted and approved in the annual budget process.[189]

Overland requested the work authorization, approval and review documents for substation/switching station, overhead line and transformer work charges in June and July 2009. The requested documents included service requests, work orders, work scope descriptions, cost estimates, evidence of approvals

[184] Response to Discovery, OC-737.
[185] Response to Discovery, OC-1208.
[186] Response to Discovery, OC-1254, OC-1255, OC-1256 and OC-1257.
[187] Response to Discovery, OC-737.
[188] Response to Discovery, OC-1254, OC-1255, OC-1256 and OC-1257.
[189] Response to Discovery, OC-1257.

and cost detail. PSE&G did not provide any documents. PSE&G indicated that service requests, scope documents and specific approvals were not required because the work was very routine.[190]

PSE&G does not prepare any monthly reports that summarize PS Power charges to the utility. The only monthly report is the intercompany billing summary schedule.[191] That report lists charges for the current month by source system. The report does not include meaningful descriptions of the nature of the charges and does not summarize the charges into meaningful categories. PSE&G's management reports for PS Power charges to the utility are inadequate.

Overland requested a breakdown of PS Power's charges to PSE&G for 2007, 2008 and 2009. PSE&G provided a single month and requested a reduction in the scope of the request because of the effort required to produce the data. Overland reduced its request to monthly data for calendar year 2009. PSE&G indicated that it would take eight to ten weeks to provide the data because of the time consuming and data intensive process required to compile the data.

PSE&G provided the last of the 2009 monthly data nine weeks later. PSE&G broke the charges into 18 to 25 line items for each month. Examples of line item titles included building maintenance, Infrared inspections, transformers and Maplewood Lab support.

Overland asked for a breakdown of the monthly amounts by work order for four of the largest categories. PSE&G only provided five months of detail "due to the complexity, formatting, and verification associated with gathering the data." [192]

PSE&G's inability to provide basic support for the charges in a timely fashion demonstrates the lack of adequate management reporting for PS Power's charges to PSE&G.

PSEG has extensive internal control procedures for purchases from outside vendors. PSEG's supply chain management (SCM) procurement practices require the following:[193]

- documented scope of work;
- cost estimate;
- competitive quotations or bids;
- purchase order or contract;
- contract approvals;
- change orders;
- completion record; and
- procurement documentation files.

[190] Response to Discovery, OC-1257.
[191] Response to Discovery, OC-871.
[192] Response to Discovery, OC-1253, OC-1254, OC-1255 and OC-1256.
[193] Response to Discovery, OC-857.

Those controls do not apply when PSE&G purchases services from PS Power. PSE&G has never used competitive bidding for any of its non-power purchases from PS Power.[194]

PSEG's Internal Audit Department reviewed PSE&G's purchases of non-power goods and services from SMD in January 2005. The audit noted that PSE&G had not subjected the purchases to competitive bidding and recommended clarifying the affiliate relations requirements for utility transactions with SMD.[195] The action plan for the audit included:[196]

- Creating a new PSE&G practice communicating the restrictions placed on utility purchases from SMD;
- Preparing a competitive analysis of SMD charges compared to other potential vendors considering quality of work, safety and other relevant factors;
- Updating the competitive analysis annually; and
- Subjecting transactions between PSE&G and SMD to the same operating controls that apply to outside vendors, including documented scope of work, strategic sourcing and change orders.

PSE&G prepared a competitive analysis of three of the services provided by SMD: (1) rebuilding transmission splice chamber enclosures; (2) gas delivery meter change work; and (3) HVAC work.

The estimated value of the transmission splice chamber work was $500,000. PSE&G solicited bids from three suppliers for that work and received two responses. Both bids resulted in higher costs than SMD.[197]

PSE&G solicited seven bids for the gas meter change work and did not receive any responses. PSE&G compared SMD's charges to PSE&G's internal costs and concluded that SMD's charges were lower than the internal costs.[198]

PSE&G received one proposal for the HVAC work. PSE&G compared SMD's average labor costs to the loaded labor rates contained in the proposal and concluded that SMD costs were lower.[199]

The recommendations to create a new procurement practice and to subject purchases from PS Power to the controls applied to outside vendors were not implemented.

<u>Recommendation: PSE&G should improve its internal controls over charges from PS Power.</u>

PSE&G should implement the following improvements to its internal controls over purchases of non-power services from PS Power:

[194] Response to Discovery, OC-1087 and OC-1088.
[195] Response to Discovery, OC-440.
[196] Response to Discovery, OC-1087.
[197] Response to Discovery, OC-1087.
[198] Response to Discovery, OC-1087.
[199] Response to Discovery, OC-1461, page 32.

- Prepare separate annual scope of work and cost estimate documents for MTS, SMD and CMS charges to the utility;
- Prepare separate monthly reports for MTS, SMD and CMS charges showing recorded and planned costs by service category on a current month and year-to-date basis;
- Prepare separate annual service completions reports that explains the services actually provided during the year and significant variances between planned and recorded charges; and
- Prepare competitive analysis of the services provided by MTS, CMS and SMD every three years as required by the BPU's Holding Company Rules.

The annual scope of work documents should list and describe the expected services for the upcoming calendar year. The scope documents should include the estimated total charges for each category of service broken down by utility client department. The scope documents should be prepared by the applicable service provider (MTS, SMD or CMS) and be approved by the utility clients.

The management reports should be prepared by the service provider. The client utility departments should be tasked with reviewing the reports for erroneous or excessive charges. The annual service completion reports should be prepared by the service provider and be approved by the client departments. The service completion reports should include a schedule showing charges to each utility client department by SAP order and month.

Charges from other PS Power departments should require a separate service completion record that explains the scope and need for the services. The service completion records should be prepared throughout the year as the services are performed. The service completion records should be approved by the utility client department verifying that the services were received. Any charges without an approved service completion record should not be billed to PSE&G.

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18. Gas Procurement and Supply

Introduction and Summary

This chapter addresses Public Service Electric & Gas' ("PSE&G") gas procurement and supply function for the distribution of gas to customers. The central components of gas procurement and supply include the demand forecast, cost of gas, and the delivery of sufficient gas supply at the PSE&G's city gate stations to meet the customer demand. Two associated subjects, gas supply reliability downstream of the City Gate Station and affiliate transactions are addressed in Chapter 20 - Gas Distribution Delivery and Operations Management and Chapter 2 - Overview of Affiliate Relationships and Transactions, respectively.

In 2009, the BPU completed an Analysis of the Gas Purchasing Practices and Hedging Strategies of the New Jersey Major Gas Distribution Companies. The report evaluated New Jersey gas utilities' natural gas hedging activities over the period from 2001 to 2007. This report provided recommendations as to how PSE&G might improve the structure of its program. For this reason, the subject of gas price hedging strategies is not significantly addressed herein.

Our assessment focuses on PSE&G's management of Gas Procurement and Supply activities. We also reviewed the Gas Purchasing Practices and Hedging Strategies report and address the applicability of the report recommendations to enhance PSE&G's hedging program.

Summary of Findings

1. The current monthly demand forecast model methodology shows very good correlation to actual monthly billing data, but communicates no information about forecast uncertainty. Additional insight into the underlying assumptions and results can be gained through Monte-Carlo Simulation.

2. Like the monthly demand forecast, additional insight into the underlying assumptions in peak-day demand can be gained through Monte-Carlo Simulation. Furthermore, since the peak-day forecast is affected by customer class mix, the forecast model should be recalibrated.

3. PSE&G is well positioned to administer gas procurement and supply, but not manage this function. The gas procurement and supply function, and in effect its management, is outsourced to PSEG Energy Resources & Trading. PSEG ER&T has a high level of skills and capabilities and sophisticated tools and methodologies to manage the gas procurement and supply program.

4. PSE&G has a solid internal auditing program. The annual audits of PSEG ER&T's adherence to policies, procedures, contacts, and transactions assure a high level of compliance. As long as PSEG ER&T has a plausible basis for its allocations, PSE&G internal audit can be expected to accept the allocation, even if better methods are available. PSEG internal audit cannot be

expected to aggressively challenge questionable cost allocations between PSEG Power and BGSS. Regulatory oversight is needed to protect BGSS customers.

5. While the internal auditing program can monitor compliance, PSE&G lacks adequate measures to effectively assess PSEG ER&T's performance with regard to the Gas Requirements Contract, Gas Supply, Storage and Transportation Procurement, and Price Hedging Strategy.

6. The Gas Requirements Contract provides for PSEG ER&T to negotiate contracts, that in its good faith judgment, to be necessary and useful for the purpose of fulfilling its obligations under the Contract, without notice, review, or approval of PSE&G and for which PSE&G could be obligated when the Gas Requirements Contract is terminated.

7. While PSEG ER&T is capable of fulfilling the Gas Requirements Contract obligations, the Gas Requirements Contract was issued on a non-competitive basis to PSE&G. (PSEG Power is the dominant electricity generator in the geographic area.) The practice of outsourcing a distribution's gas supply to an affiliate not regulated by the state is not a general industry practice.

Recommendations

1. PSE&G should employ Monte-Carlo Simulation or similar techniques to better communicate the gas demand drivers and forecast uncertainty. Likewise, PSEG ER&T should employ similar techniques to better communicate to PSE&G the forecast price and cost of gas to PSE&G delivery points.

2. PSE&G should establish written performance expectations of ER&T. We suggest these expectations address transparency, accountability, and accuracy. Performance measures for consideration include:
    - Price volatility.
    - Potential cost and out-of-market outcomes tolerance.
    - Utilization of firm capacity.
    - Capacity release target.

3. PSE&G should reassess the value of its Gas Requirements Contract by either:
    - Issuing a competitive bid request for proposals to prequalified bidders, or
    - Preparing a study and cost/benefit analysis of terminating the ER&T contract and submit the study in its next BGSS proceeding.

4. PSE&G should amend the Gas Requirements Contract to provide for the following provisions:
    - Advance written notification of any negotiations which could pose an obligation to PSE&G when the Gas Requirements Contract is terminated; and

- Written support demonstrating the need, cost, and benefits of all negotiated contracts which pose an obligation to PSE&G when the Gas Requirements Contract is terminated.

5. The Gas Requirements Contract should be modified to address:
   - Audits performed on behalf of the NJBPU.
   - Provide for intra-day nominations.
   - Approval of changes in Storage and Transportation contract quantities.
   - Approval of firm gas supply contracts of longer than one year.

Technical Analysis

Background

In Docket Number GM00080S64, dated April 7, 2002, the New Jersey Board Public Utilities ordered that PSE&G transfer all gas commodity and capacity agreements and related instruments to its unregulated affiliate PSEG Energy Resources and Trade, LLC ("ER&T"). Based on the Order, the requirements were that:

- PSE&G enter into a full requirements contract with ER&T to supply basic gas supply service (BGSS).
- ER&T holds PSE&G's natural gas interstate capacity, storage, and supply contracts.
- The Board has the ability to hold PSE&G responsible for BGSS service and to regulate the terms and conditions of that service.
- PSE&G's proposal as amended through the Addenda provides a fair value to the ratepayers through a reallocation of supply risks, enhanced supplier services, which may spur the competitive gas market, and market-based pricing for commercial and industrial (C&I) customers.
- Under the Settlement Agreement, pricing customers in a comparable way as competitive suppliers is the key to competition in the C&I customer classes.
- Under the Settlement Agreement, PSEG ER&T and suppliers are both at risk for the recovery of the fixed cost obligations under the pipeline contracts held to service their customers.
- PSEG ER&T is committed to provide the BGSS requirements of PSE&G and to make capacity available to those licensed suppliers desiring to use it to serve PSE&G customers as well as to New Jersey generators, when excess capacity exists.
- Customers that do not receive gas supply from a TPS will be supplied under the Basic Gas Supply Service-RSG (BGSS-RSG) default service.
- Should the Board have reason to believe that undue market power was developing in either the electric or natural gas arenas, the Board has the authority to investigate such allegations

and take such actions, including filing a complaint with FERC, or other regulatory authority, as may be warranted to remedy the situation.

- The Board emphasizes that it will continue to exercise its jurisdiction to regulate BGSS rates, terms, and conditions as required by EDECA.

In January 2007, the NJBPU issued a Request for Proposal (RFP) to perform an analysis of the gas purchasing practices and hedging strategies of the state's major Gas Distribution Companies (GDCs). The report presented a number of general, as well as specific findings regarding PSE&G's gas purchasing practices and hedging strategies:

- The current hedging programs include elements fundamental to sound risk management, including:
  - basic programmatic (non-discretionary) hedging;
  - the use of financial hedging tools by some of the GDCs; written procedures; and
  - active risk management oversight committees.
- These elements have been deployed to reduce customers' exposure to market prices; they also provide a foundation upon which improvements can be made.
- For the historical period analyzed, the hedging programs narrowed the range of price outcomes compared to what would have occurred had they simply floated with the market.
- The current hedging programs do not include protocols that monitor and respond to increasing prices and volatility, rather, they deploy a relatively consistent strategy in all market environments.
- PSE&G has target hedge ratios, all hedge up to 18 months in advance of delivery on a non-discretionary basis and use fixed-price instruments (futures, financial swaps/physical forwards).
- PSE&G does not use financial options in their forward hedge programs.
- The state's BGSS customers are exposed to potentially significant future bill impacts.
- Comprehensive governing policies are in place and have been internalized in the organization.
- BGSS Services is the single organization in the gas supply process that has direct accountability for the regulated utility services customer base.
- The organizations in ERT that manage the gas supply and hedging efforts are fulfilling their responsibilities to the existing program in an effective and professional manner.
- The various organizational relationships of Internal Auditing provide for independence, yet allow effective working relationships with other compliance and governance functions.
- The internal audit function contributes to a viable BGSS program via annual audits of ERT's implementation of the contract.

- PSE&G has a comprehensive enterprise risk management function in place and a sound process by which it manages that program.
- The objectives of the hedging program, as codified in their risk management policies lack certain elements and specificity inherent in a more robust approach, specifically, no defined tolerance thresholds or use of Value-at-Risk (VaR) monitoring metrics in its forward hedge program.
- Hedging program does not explicitly balance the mitigation of rising prices (upside risk) with the mitigation of out-of-market risk.
- The portfolio monitoring functions need to be separate from the front office execution.
- A review of sample transactions suggests full compliance with complete and accurate transaction documentation readily available.
- PSE&G has a strong internal audit program in place and supporting controls that assure a high level of compliance.

PACE's recommendations in the hedging audit it conducted center on aligning policies and procedures in a way that will produce more robust mitigation of price spikes and more stable cost outcomes going forward.

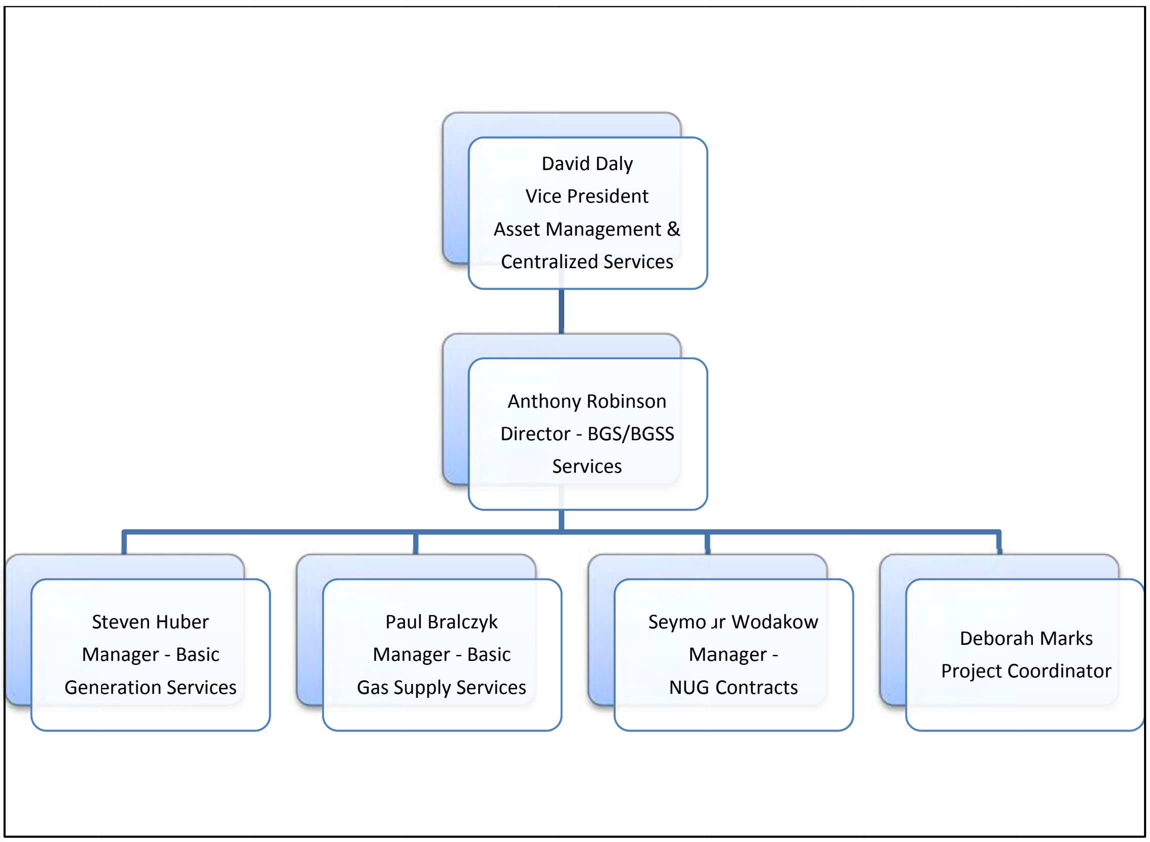
- PSE&G should define program objectives explicitly in terms of potential cost and out-of-market outcomes that are tolerable. PSE&G's current objectives, while laudable in intent, are too ambiguous to translate into a clear set of decision rules.
- PSE&G's program should be structured so as to ensure a hedge ratio is established well in advance of delivery to pre-empt the situation of hedging precipitously during the highly-volatile portion of the curve, where divergence of market settlements from current forward prices is apt to move substantially.
- PSE&G should more clearly define its discretionary protocols/triggers, and link them to forward-looking prices as opposed to historical indicators. The current program's decision metrics regarding when, how much, and how far forward to hedge are not well defined.
- PSE&G implement discretionary protocols for a minimum 18-month horizon in order to capture value opportunities over a longer market cycle and help stabilize rates over multiple BGSS cycles.
- PSE&G should institute VaR-based defensive protocols such that hedge positions are taken when volatility threatens tolerance thresholds.
- PSE&G should determine its hedging program modifications on the basis of multiple simulations of varying decision rules.

A complete description of PSE&G hedging strategy is documented the NJBPU's Gas Purchasing Practices and Hedging Strategies of the New Jersey Major Gas Distribution Companies report.

PSE&G Gas Supply Organization

The expertise in gas procurement lies within PSEG ER&T. PSEG ER&T takes the lead role in defining supply options, including hedging strategies. The BGSS Services organization is an arm of the Business Analysis unit in PSE&G. Their role is to provide the appropriate direction and oversight of supply hedging and hedging. They are the only entity within the gas supply process that directly represents PSE&G. The Basic Gas Supply Service Manager, part of the Business Utilities Analysis administers the Requirements Contract. The Basic Gas Supply Service Manager reports to the director of BGS/BGSS. The Business Utilities Analysis has a staff of seven people.

Table 18-1 - PSE&G Gas Supply Organization Chart



PSEG Energy Resources & Trade (ER&T) manages PSEG Power's generation portfolio and basic gas supply service, the purchase of fuel, and buys and sells electric and gas commodity. ER&T's responsibilities include: management of PSEG Power's generation portfolio and basic gas supply service, purchasing of fuel, mid- and back-office operations as well as trading and marketing activities. Within PSEG ER&T there are two groups that provide gas supply services. The gas supply services are provided by Gas Trading (front office) and Gas Scheduling (mid office). All back office functions are performed under the direction of accounting services, which is independent of ER&T. Gas supply transactions are originated in the Gas Trading section of Gas supply within ER&T. Gas traders make all of the BGSS purchases, which take the form of forward physical contracts. Based upon availability, PSEG ER&T also sells gas to others.

The vice president of Gas Supply for PSEG Energy Resource & Trade, who has overall P&L responsibility for the gas contract portfolio of ER&T, including responsibility for long term capacity acquisition, gas trading, and regulatory matters related to gas supply and price issues before the Federal Energy Regulatory Commission, reports to the president of PSEG Energy Resources & Trade.

BGSS hedge executions are performed by PSEG ER&T and monitored by PSE&G. PSEG ER&T's risk management practice for basic gas supply service (BGSS) was reviewed and approved by the Risk Management Committee and governs the hedging activities conducted by PSEG ER&T on behalf of the BGSS customers. Monitoring of the hedging activities is jointly performed by PSEG ER&T's VP Gas Supply and PSE&G's Business Analysis unit.

Gas Commodity Procurement

PSE&G is responsible for preparing a forward-looking annual demand forecast. Using the demand forecast provided by PSE&G, ER&T prepares a forward-looking supply plan. The supply and demand requirements are weather normalized. Normalizing supply and demand requirements is a common industry practice. PSE&G files this data with the NJBPU in an Annual Supply/Demand Report.

Heating Degree Day Index

PSE&G's modified Heating Degree Day Index should better reflect the effect of weather on sales demand during the shoulder months, critical months when large day-to-day demand swings are more likely and gas from storage may not be available. Weather is incorporated into the econometric models by using the index, heating degree days (HDD). For forecasting billed gas sales, weather data collected by the National Oceanic and Atmospheric Administration (NOAA) from Newark International Airport is used. Prior to 2008, heating degrees were calculated using a 65 degree base.

Now, PSE&G uses a modified heating degree index. The index is modified from the standard index in two ways. The number of heating-degree-days is calculated using the daily temperature as the average of the 24 hourly observations as compared to the average daily of the high and low temperatures. The average of the daily 24 hours more accurately reflects the distribution of the temperature, and as a result the total daily heating load, than the average of the daily high and low. To determine the appropriate base temperature to use for gas sales, PSE&G compares daily gas send-out to firm customers with the average daily temperature to identify the temperature at which heating load starts. Send-out data from 2005 through 2007 for three day-types - weekdays, Saturdays, and Sundays/Holidays – was used. The base temperature used in the HDD calculation was changed from the standard of 65°F to 60°F.

"Normal" weather for forecasting purposes is assumed to be a 20-year average of the daily HDD aggregated to calendar - and billing-month utilizing the data from the 1988 - 2007 time period. The following table shows the normal values on a calendar-month basis calculated on a 65°F base using both the average of the daily high and low temperatures (Hi/Lo) and the average of the 24 daily hours (24 Hour) and with the 60°F base utilizing the average of the 24 hours.[1]

Table 18-2 - Calendar Month Normal Heating Degree Days

Month	65° F Base		60° F
	Hi/Lo	24 Hour	24 Hour
January	977.5	994.3	821.2
February	865.2	857.5	720.1
March	697.1	702.8	557.8
April	369.6	391.7	267.4
May	126.2	165.1	75.6
June	13.6	26.1	6.3
July	0.2	2.3	0.2
August	0.8	4.2	0.3
September	35.5	56.3	19.8
October	260.1	283.2	163.8
November	528.8	537.2	389.2
December	861.5	856.9	703.4
Annual	***4,736.1***	***4,877.6***	***3,725.1***

Demand Forecasts

The PSE&G methodology employed to create the annual Monthly, Peak-day, and Daily annual demand forecasts, which are provided to ER&T, has been in place since the 2008 forecasting cycle. Prior to 2008, the econometric models were disaggregated to only the customer class level.

PSE&G's current monthly demand forecast model methodology shows very good correlation to actual monthly billing data and the forecast methodology2 is well documented. Residential gas sales are determined by the number of residential customers and the amount of gas that each of these customers uses. PSE&G disaggregates residential sales into two components:

- The estimate of what, on average, each residential customer will use, and
- The projection of the number of residential customers.

The demand component used in the model is a function of heating degree days, real price of gas, and real per capita income. The All Urban Consumer Consumers' Price Index is used in deriving the real price of gas. Personal income is obtained from the U.S. Department of Commerce, Bureau of Economic

[1] Response to Discovery, OC-631 Forecast Methodology
[2] ibid

Analysis. The residential forecast of the number of residential natural gas customers is based on historical trends between customer growth and residential construction activity in the service area.

The demand components of commercial gas sales are similar to residential, except for capita income. The commercial model assumes that the demand for local commercial output is a function of local economic and demographic factors. GSG customers are disaggregated into two groups and modeled separately: those with gas space heat and those heating with other fuels. Likewise, LVG customers are modeled separately.

The demand of industrial gas sales in PSE&G's service area is for employee workspace heating, not process heating, and as such, the demand components used in this model are a function of heating degree days, real gas price, and manufacturing employment.

The current peak-day forecast methodology is an improvement. PSE&G bases the peak-day send-out forecast on a regression analysis of actual daily firm send-out data. The regression analysis determines the relationship between firm send-out and weather. The peak-day send-out model takes into consideration:

- Heating degree days
- Day of the week
- Non-weather induced seasonal patterns

As a result, the peak-day estimate is limited to the likely peak-day months, January and February.

The peak-day send-out is determined by using the forecast model to calculate the daily send-out when the average temperature is zero degrees. This peak-day value is expected to increase at the same rate as annual firm sales; a reasonable assumption.

Prior to 2008, the peak-day forecast models differed. Rather than restricting the data to January and February, it was restricted to weekdays where the average temperature was less than 55 degrees. In addition, the forecast was based on trending recent peaks, not on the projected trend in sales.

Between 2005 and 2009, peak-day send-out forecast, based on PSE&G Corporate Energy Forecast, and total peak-day capacity requirements to meet the peak-day planning criteria for 2008/2009 have decreased 5.0% and 3.2%, respectively.
Over this same period, peak-day supply has gone from a forecast 184.3 MDth/day deficiency to a 60 MDth/day surplus, deferring the need to procure additional gas supplies and transportation services. This surplus represents 2% of available total gas supply on a peak-day.

Table 18-3 – 2008-2009 Peak Day

Source	Peak Day, MDth/d		
	2005	2007	2009
Total PSE&G Gas Supply	2,920.4	3,036.3	3,070.9
Peak Day Send-out Forecast	2,894.0	2,820.0	2,743.9
Total Peak Day Capacity Requirements	3,104.7	3,026.8	3,010.9
Surplus / (Deficiency)	***-184.3***	***9.5***	***60.0***

In response to earlier PSE&G's supply forecasts, PSEG ER&T entered into Precedent Agreements in 2006 for incremental transportation capacity from Texas Eastern and Transco of 50,000 MDth/day each. These services commenced in November 2008 and 2009, respectively. PSEG ER&T reports there have been no increases in the gas supply and transportation portfolio since that time.

PSE&G's daily firm demand send-out estimate forecast is a valuable tool in gas procurement and supply planning. Prior to 2008, PSE&G did not provide daily forecasts to ER&T.

The daily send-out forecast is based on a regression analysis of actual daily firm send-out data. PSE&G uses a firm daily send-out model that considers such factors as weather, other non-weather factors, the day of the week, and non-weather induced seasonal patterns. Also considered is the influence that the customer mix between the residential, commercial, and industrial sectors can have on the relationship between send-out and any other factors. Since class-specific send-out data is not available, the time series analysis is restricted to the most recent year to allow for sufficient data points.

The forecast model produces a forecast of daily send-out based on daily normal weather. A 20-year normal is used for daily-load forecasts and is updated annually.

Gas Prices

The sources of gas price data PSEG ER&T subscribes to include: Gas Daily, Inside FERC Gas Market Report, and Natural Gas Week.

ER&T does not regularly prepare natural gas price forecasts; rather it relies almost exclusively on NYMEX pricing plus fixed and other pipeline charges. On an annual basis, ER&T provides pricing information, based on the forward NYMEX prices, for use in PSE&G's BGSS filing. During the course of the year, ER&T will update these prices based on movements in the NYMEX in order to determine the accuracy of the original filing.

The majority of the non-hedged supplies purchased by ER&T are based on NYMEX closing prices. This allows the prices paid for purchased gas to be in line with the monthly BPU approved pricing formulas for certain BGSS customers.

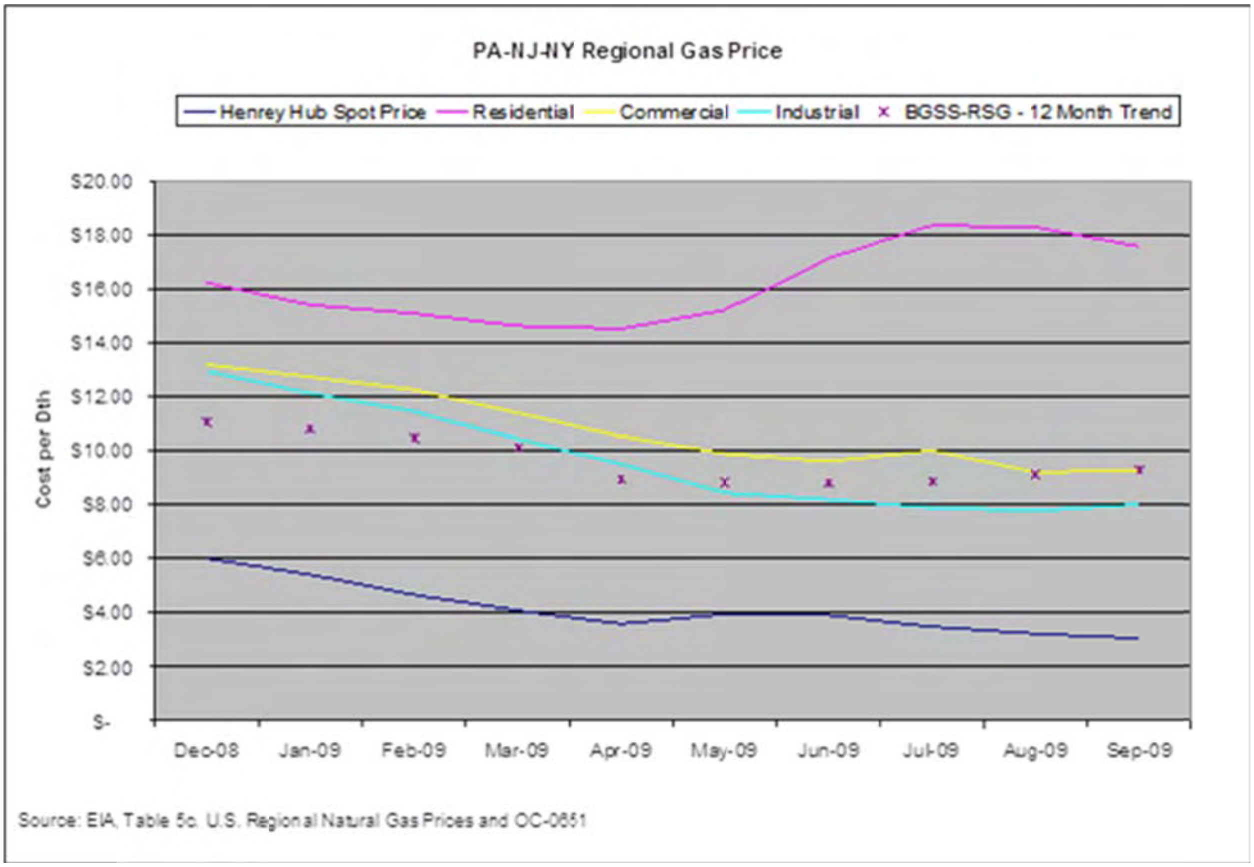
Price volatility is an important performance measure of a BGSS gas supply procurement strategy. PSE&G does not measure month-to-month volatility. PSE&G reports that the weighted average inventory method of accounting for gas purchases eliminates any significant volatility for its residential gas supply portfolio. In using the weighted average inventory method, all volumes purchased for a particular month and all related cost (both fixed and variable) for that month are added to the beginning inventory for a total available for that month. The volume of gas send-out for the month is priced at the average available inventory price and then deducted from the available inventory. The end result is an ending inventory balance (volume and cost) which is in effect the storage balance at the end of the month.

In the following table is PSE&G's gas cost 12-month trend for BGSS-RSG,[3] which is well below that of the mid-Atlantic region residential gas costs as reported by EIA. The BGSS-RSG cost is the total delivered cost to residential customers based on actual dollars and volumes from a PSE&G 2009 Tariff Reconciliation. The mid-Atlantic region includes the states of Pennsylvania, New Jersey, and New York. The EIA cost[4] is based on revenue, including taxes and the volume for deliveries of natural gas that the utilities own.

[3] Response to Discovery, OC-651.

[4] The volume reported to EIA in Mcf @ 14.73 psia-60ºF have been converted to Dth assuming 1000 BTU per cubic feet @ 14.73 psia-60ºF.

Table 18-4 – PA-NJ-NY Regional Gas Price



Gas Supply

PSE&G ER&T performs the gas commodity purchasing functions for PSE&G. In 2008, PSE&G's gas supply requirements totaled 2,139 million therms. PSE&G is also the supplier of last resort should a third-party supplier fail to deliver gas to PSE&G's delivery point. The following table provides a breakdown of gas supply between PSE&G customers and third-party suppliers.

Table 18-5 – Breakdown of Gas Supply Between PSE&G and Third-party Suppliers

YEAR ENDING 2008[5]	Millions Therms	%
PSE&G	2,139	62 %
Third-Party Suppliers	1,302	38 %
Total	**3,441**	**100 %**

[5] Response to Discovery, OC-211.

PSEG ER&T develops a winter seasonal plan to determine supply requirements based on normal weather. The first component of the portfolio is the volume of the gas that has been hedged for the season for the residential customer. PSEG ER&T evaluates how much seasonal gas it will acquire. These requirements are priced based on a monthly NYMEX. The decision as to how much to acquire is based on ER&T's opinion of market dynamics, forecasted weather, current storage inventories, and where prices have been trending.

PSEG ER&T meets with PSE&G prior to each month to refine its strategy and to assure that it has acquired enough gas for seasonal and monthly purchases, and to meet the normal requirements of the commercial, industrial, interruptible, and cogeneration customers whose rate is based on a NYMEX price.

The gas that PSEG ER&T acquires for PSE&G reflects the philosophy of obtaining a mix of supplies that are priced on both the daily and monthly markets as well as obtaining supplies for the residential customer that are hedged at a fixed price for price stability.

Like a well-documented gas hedging strategy, the programmatic use of the Bollinger Band method when properly documented can be audited as a means to assure price triggers/purchasing decisions are supportable and not speculative. The Bollinger Band[6] can aid in rigorous pattern recognition and is useful in comparing price action to the action of indicators to arrive at systematic buying decisions. The method is a tool to give an indication of price movement; it cannot predict an absolute high or low price. PSEG ER&T uses the Bollinger Band as a tool to assist in determining when it may be more advantageous to hedge a portion of the residential customer's gas supplies. The default parameters for a standard technical analysis are the 20-day volatility and 2 standard deviations. The band is utilized as a reference point or a trend tracker for determining when to hedge for a given period. In addition to the Bollinger Band, which is a more statistical method, other market trends are reviewed such as rig counts, changes in demand, development of new production, and energy forecasts for future periods.

The new hedging program has not been in effect long enough to assess. The prior PSE&G hedging strategy was reviewed by the NJBPU in 2009.[7] A hedging program for PSE&G's residential customers has been in place for several years. The goal of the residential hedging program has been to achieve a level of price stability for the customer. The PSE&G program has evolved based on changes that have occurred in the marketplace.

[6] OC0648 - Bollinger Band is a technical analysis tool that evolved from the concept of trading bands. The purpose of Bollinger bands is to provide a relative definition of high and low relative to previous trades. Bollinger bands for a specific period of time consist of a middle band which is a simple moving average, an upper band which is a standard deviation above the middle band and a lower band which is a standard deviation below the middle band. By definition, prices are high at the upper band and low at the lower band. When the bands lie close together, a period of low volatility in price is indicated. When they are far apart, a period of high volatility in price is indicated. When the bands have only a slight slope and lie approximately parallel for an extended time, the price will be found to oscillate up and down between the bands as though in a channel.

[7] Response to Discovery, OC-230 – Analysis of the Gas Purchasing Practices and Hedging Strategies of the New Jersey Major Gas Distribution Companies.

Prior to the 2010 - 2011 winter season, PSEG ER&T executed a hedging program employing two specific strategies: Discretionary and Non-Discretionary. One half of the volume is hedged on a non-discretionary basis and the other half on a discretionary basis. In addition, each season, summer and winter, was considered independently with the same volume hedged for each respective season. For both strategies, hedging was commenced 18 months prior to the respective season. For each year, PSEG ER&T set a target volume which was traditionally about 65% to 70% of the total annual residential send-out. In both the summer and winter seasons, PSEG ER&T utilized Non-Discretionary hedging for 50% of the planned volume. With Non-Discretionary hedging, a ratable volume was hedged each month at certain times during the month for the respective season(s). PSEG ER&T used various market conditions and trends in deciding at what point to hedge, but the goal was to lock in approximately 1/18th of the gas each month.

Similarly, for each season, PSEG ER&T used Discretionary hedging for the remaining 50% of the planned volume. The Discretionary hedges were executed based on ongoing market conditions as well as historical pricing trends. The volume of Discretionary hedges had time triggers; at least 1/3 would be purchased no later than 12 months prior to the commencement of the respective season, at least 2/3 would be purchased no later than 6 months prior to the commencement of the respective season, and 100% of the Discretionary volume would be completed immediately prior to the commencement of the season.

For the 2010 -11 winter season, PSEG ER&T, as directed by PSE&G, began to hedge gas for the residential customer using two methods: Non-Discretionary Method and Dollar Budget Method. The Non-Discretionary Method involves hedging a relatively ratable volume of gas over an 18-month period prior to the effective winter or summer season. The hedges for the respective seasons are to be executed approximately every three weeks. The Dollar Budget Method involves the development of a monthly budget of dollars that is spent equally over a maximum of 18 months prior to the effective winter or summer season. The volumes of gas purchased each month for the prospective winter or summer season will vary based on the price for that future period on the day the hedges are executed. PSEG ER&T is expected to utilize its market knowledge and intelligence to hedge at the more opportune times. The maximum annual targeted volume will be approximately 70.0 bcf split evenly between the summer and winter seasons. Further, both of the two methods will be split evenly within the seasons. Both methods commence 18 months prior to the respective winter or summer season. Prior to entering a winter season, at least 65% of the estimated residential send-out in a normal year will have a known price comprised of the sum of hedged gas at a known price and gas in storage.

The new hedging strategy adopted and approved by the Risk Management Committee has resulted in no changes in the way trades are reconciled or reported.

Gas Accounting Information Systems

Cost allocation to off-system sales and gas supplies for electric generation is accomplished by the Gas Automated Allocation System (GAAS). Using trades and tariff data available in GasMaster daily weighted average costs are calculated and applied to off-system sales volumes and volume allocation for electric generation.

PSEG ER&T information systems, supporting reports, and other documentation demonstrate adequate accounting controls. The PSE&G / ER&T Risk Management Practice for Basic Gas Supply Services (BGSS)[8] provide a defined process for the Residential Hedge Program. Specific residential hedging volumes, timeframes, and accountabilities are documented in this practice.

Processes are in place to ensure that physical gas hedges are correctly classified and booked regarding their expected use.

Transactions are executed and documented in accordance with ER&T's Trade Ticket Preparation practice. This includes:

- Documenting trades on trader prepared trade tickets.
- Assigning the trades to a designated "Book" based on the intended purposes.
- Recording the trade in the physical gas deal entry system (Gas Master).
- Obtaining the appropriate approvals for trader limit purposes.

GAAS is designed to capture all BGSS physical gas transactions and perform the applicable weighted average cost of gas calculations used by Accounting Services to record the gas costs to the appropriate general ledger accounts.

There are multiple modules in the GAAS which support this process.

- The Tariff module allows the user to enter pipeline tariffs in GAAS, which are automatically downloaded to the GasMaster database when the user saves the information.
- The Virtual Path module allows the user to build paths, which will be used to apply tariff rates to purchases.
- The Report modules calculate virtual costs based on designated paths and the related tariff rates and provide summarized results by book and in aggregate.

BGSS-related "Books" are assigned/owned at a manager level or higher. The "Book Owner" is responsible for reviewing all trades recorded in the applicable BGSS "Books" on a daily basis via a "Book Owner Report" and approving the "Book" classification.[9]

[8] OC 645 - PSE&G / ER&T Risk Management Practices for Basic Gas Supply Service (BGSS).
[9] This process is defined in ER&T's Sarbanes Oxley control process documentation and reviewed at least annually by internal and external auditors.

The following table provides a description of the various daily and monthly reports that are utilized.

Table 18-6 – Various Daily and Monthly Reports

Daily Reports
▪ Virtual Nomination report – applies virtual paths and the related costs to each purchase by book.
▪ Unmoved Purchases report – lists purchases where no virtual path has been defined. Report will not generate if all purchases have virtual paths defined.
Monthly Reports
▪ GDAY Allocation report – a summary of activity in the GDAY book after virtual costs have been applied.
▪ GSYS Allocation report – a summary of activity in the GSYS book after virtual costs have been applied.
▪ Cost Allocation for Gas for Electric Generation – summary of costs which will be allocated to Gas for Electric generation inventory.
▪ Gross Margin GOSS Wholesale Off System Sales – summary of revenues and costs for daily sales.
▪ Gross Margin GOAK Wholesale Off System Sales – summary of revenues and costs for sales related to Red Oak facility.
▪ Gross Margin GOSM Wholesale Off System Sales – summary of revenues and costs for monthly sales.
▪ Gross Margin GBTB Wholesale Off System Sales – summary of revenues and costs for Back to Back sales.
▪ Gross Margin GOSS,GOAK, GBTB and GOSM combined – summary of revenues and costs for all off system sales.
▪ Summary of Gross Purchases – GasMaster Tie – summary of gross purchases in GAAS which is reconciled to GasMaster. This report is generated to insure the data feeding GAAS is complete.

PSE&G ER&T uses Sunguard ZaiNet to support its front, middle, and back office functions.

GasMaster is an integrated enterprise solution tool for entering, tracking, and implementing information related to PSEG ER&T's business processes. GasMaster's database consolidates information on business associates, contacts, facilities, station, pricing, paths, contracts, gas control, supply planning, and accounting in a single repository. It enables the use of standard methods of online data entry and retrieval across all functional areas. It allows automated deal confirmations via fax, ad-hoc reporting, and automated wire transfer of account purchase and sales documents.

Spot Market Gas Procurement Strategies

Changes in TPS accounts directly affect both the gas procurement strategy and PSEG ER&T's revenue. The following table summarizes the residential participation in the Third-Party Supplier Option. The growth of eligible residential customers in New Jersey to participate in purchasing gas supplies from third-party supplies is similar to that of New York and Pennsylvania. Although New Jersey residential participation levels have increased at a compounded average growth rate of 15.5% from December 2005 to December 2009, the level of participation is far below that of both New York and Pennsylvania. The percentage of participation by December 2009 in New Jersey was 2.24% compared with 16.02% and 6.97% for New York and Pennsylvania, respectively.

Table 18-7 - Residential Participation in Third-Party Supplier Option

	Residential Participation Levels					
State	Dec-05	Dec-06	Dec-07	Dec-08	Dec-09	CAGR
NJ	33,327	37,586	46,748	56,494	59,207	15.5%
NY	328,552	383,613	486,826	588,669	687,245	20.3%
PA	164,668	178,955	160,033	185,387	183,641	2.8%
					Residential Eligibility Levels	
NJ	2,582,714	2,578,191	2,581,066	2,601,051	2,638,783	0.5%
NY	4,199,302	4,315,203	4,263,098	4,303,335	4,290,331	0.5%
PA	2,591,458	2,605,782	2,582,841	2,631,340	2,633,384	0.4%
					Percent of Participation	
NJ	1.29%	1.46%	1.81%	2.17%	2.24%	
NY	7.82%	8.89%	11.42%	13.68%	16.02%	
PA	6.35%	6.87%	6.20%	7.05%	6.97%	
Source: EIA Natural Gas Residential Choice Programs						

The following table shows that the growth in PSE&G customers' participation has grown at a compounded average growth rate of 14.4% from December 2005 and October 2009.

Table 18-8 - PSE&G Third Party Supplier Accounts[10]

		Accounts As of December		
Year	Third-Party Suppliers	Total	Increase	Percentage Change
2005	22	22,420		
2006	21	22,378	-42	-0.2%
2007	20	28,266	5,888	26.3%
2008	18	33,685	5,419	19.2%
2009*	20	38,535	4,850	14.4%
*Account total as of October 31, 2009				

Interstate Pipeline Transportation

PSEG ER&T has a large portfolio of pipeline capacity and storage contracts that are the main component in meeting the supply needs of the BGSS customers. The service provided to PSE&G is essentially a full requirements sales service that primarily utilizes these assets to meet the needs of the customers.

PSEG ER&T is obligated to meet the peak-day and seasonal needs of the firm customers of PSE&G as forecasted by PSE&G. PSEG ER&T is responsible for securing capacity at the most reasonable rate, while considering reliability and the location of the receipt and delivery points.

PSE&G has four direct connections with interstate pipelines that deliver supplies of natural gas to New Jersey: Transcontinental Gas Pipeline, Texas Eastern Transmission, Tennessee Gas Pipeline, and

[10] Response to Discovery, OC-228 – TPS Customer Activity.

Columbia Gas. These pipelines account for the majority of the daily and peak-day gas required to serve the firm customers of PSE&G, with the balance being essentially provided by LNG and LPA.

The transportation contracts are from the Gulf Coast, market area hubs, and the Canadian border. Several of these services are rendered by upstream pipelines with the ultimate delivery provided by the four direct connect pipelines. The pipeline capacity is utilized taking into consideration the basis differential of the gas at the receipt points and the variable cost of delivery.

Table 18-9 - Summary of Firm Gas Transportation for BGSS

	MDTh		
Source	**2005**	**2007**	**2009**
Pipeline Firm Transportation			
Transco FT	432.4	432.4	432.4
Transco FTNT	108.7	108.7	108.7
Transco Niagara	0.0	119.4	119.9
Transco/Tetco Leidy (DTI)	92.2	94.3	106.4
Transco Sentinel	0.0	0.0	0.0
Texas Eastern FT	231.6	231.6	231.6
Texas Eastern ITP	110.0	110.0	110.0
Texas Eastern Time II	0.0	50.0	50.0
Tennessee FT	36.4	36.4	36.4
Columbia FTS	12.5	25.0	25.0
Texas Gas DTI	13.3	0.0	0.0
NIPPS	87.1	0.0	0.0
Duke Base Load Supply	0.0	0.0	0.0
NJEA	21.8	0.0	0.0
Total Firm Transportation	***1146.0***	***1,207.9***	***1,220.4***
Local Supplies*	*12.3*	*12.3*	*12.3*
*Refinery and landfill gas			

About 40% of PSE&G's peak gas requirements come from firm transportation. The remainder of PSE&G's requirements comes from underground gas storage, LNG, seasonal purchases, contract peaking supply, propane, and refinery and landfill gas.

<u>There is no formal exchange of information between PSE&G and PSEG ER&T regarding specific locations where additional system gas supply requirements are needed.</u>

PSEG ER&T reports that it has not received nor does it require formal 5- and 10-year forecasts from Asset Management.

Since the contract transfer in 2002, PSE&G and PSEG ER&T have limited the amount of information shared, pursuant to paragraph five of the Supplemental Operating Agreement between PSEG and ER&T. This requires PSE&G to provide information about the distribution system in order for ER&T to meet future requirements. The information required by PSEG ER&T is where PSE&G anticipates growth in the distribution system and at what metering stations incremental deliveries should occur.

However, the PSE&G distribution system demand is heterogeneous, necessitating supplies at specific locations on the distribution system. This has required PSE&G Asset Management and PSEG ER&T to coordinate capacity on specific pipeline suppliers to meet these gas distribution operational needs.

Over the last several years, PSEG ER&T has increased its peak day deliverability by subscribing firm pipeline transportation. PSEG ER&T regularly reviews open season filings of the various pipelines that either connect to PSE&G or are directly upstream of those pipelines. In recent years, there have been several projects where multiple pipelines propose expanding to the northeast market. In addition, as required by the FERC, certain projects have been introduced in an open season but have specific pre-arranged participants and are designed to serve a specific need, e.g., a producer seeking to move supplies to a more liquid location. Not all projects are a reasonable or economic fit, in that the facilities are not readily deliverable to PSE&G locations. The rates for these projects are not known with any certainty until the conclusion of an open season and a true assessment of facilities can be made.

The last four pipeline expansions have been based on the location of the PSE&G requirement in its distribution system and the location of the pipeline facilities - each project met a need in a specific area.

The following projects that were designed to deliver natural gas to the region have been reviewed by ER&T over the last five years:

Table 18-10 - Projects Delivering Natural Gas

▪ Texas Eastern Team 2013	▪ Tennessee Connexion
▪ Texas Eastern Temax	▪ Texas Eastern Team
▪ Texas Eastern Northern Bridge	▪ Texas Eastern Time III
▪ Texas Eastern Time II	▪ National Fuel West to East
▪ National Fuel Niagara to Leidy OS138	▪ Algonquin East to West
▪ Columbia Crawford Storage	▪ Spectra Steckman Ridge
▪ Williams Rockies Connector	▪ Transco Northeast Connector
▪ Transco Sentinel	▪ Transco Rockies Connector
▪ Rex Northeast Express	▪ Dominion Hub III
▪ Dominion Storage Factory	▪ Tennessee Northeast Passage
▪ Tennessee Northeast Supply Diversification Project	▪ Millennium Pipeline

The following is a summary of three projects[11] reported by PSEG ER&T:

> **Incremental Columbia FT Service (January 2006)** – This project was implemented specifically for PSE&G ER&T to serve a somewhat isolated, but growing area of the PSE&G distribution system and, as such, was not a major project similar to those noted above. The facilities of Columbia were relatively close to the area in question and Columbia was able to reorient certain contract obligations on its system to be able to offer the incremental capacity.
>
> **Texas Eastern Time II (November 2008)** – In order to meet the incremental requirements that were forecasted by PSE&G for this period, PSEG ER&T needed to focus on either Texas Eastern or Transco for additional deliverability. Due to an increase in requirements throughout the core part of PSE&G's system served by its transmission line that starts in Linden as well as a growth requirement in the Jamesburg, NJ area, ER&T participated in this project with Texas Eastern since they serve both these areas. In addition, the timing of this project was flexible in that a portion of the service was available a year earlier, but was not required at that time by ER&T, and Texas Eastern offered to delay ER&T's commencement and sell that capacity to another party for a one-year period.
>
> **Transco Sentinel (November 2009)** – This project was added this past winter season and provided a diversity of delivery from both a market area pipeline hub and LNG from the Cove Point facility. ER&T was able to arrange for incremental delivery by Transco at three different City Gate locations identified by PSE&G as areas requiring future delivery due to growth in the respective areas.

ER&T can negotiate contracts or make arrangements in its good faith judgment as necessary and useful for the purpose of fulfilling its obligation to supply gas to PSE&G under the Gas Requirements Contract. PSEG ER&T has negotiated with transporters to obtain favorable terms and conditions including: negotiated rates, shorter terms, and fuel caps. The Gas Requirements Contract does not require ER&T to seek PSE&G's review or approval.

When a pipeline operator issues an OFO, PSE&G's Gas System Operations Center must be diligent in monitoring system loads and in communicating changing load forecasts to PSE&G ER&T so that appropriate gas scheduling adjustments can be made on a timely basis. Since the Requirements Contract became effective, PSEG ER&T has never received a penalty charge from a gas supplier.

PSEG ER&T was charged with a penalty from Tennessee Gas Pipeline ("Tennessee") for the two-day period of Sunday, January 20, 2008, through Monday, January 21, 2008. On January 17, 2008, Tennessee issued a Critical Day Operational Flow Order ("OFO") to be effective on Friday, January 18, 2008. Pursuant to that OFO, Tennessee shippers were to be charged a penalty of $5/Dth for any under-deliveries in excess of a 2% tolerance, based on total scheduled volumes. The three Tennessee City Gate

[11] Response to Discovery, OC-529 – Natural Gas Supply Projects.

stations on PSE&G's distribution system -- Mahwah, Ringwood, and West Milford -- are located in the very northernmost section of New Jersey, in an area only served with Tennessee's deliveries.

On days when an OFO was in effect, PSEG ER&T had scheduled gas deliveries to the Tennessee stations in excess of PSE&G's forecasted load. Those excess deliveries were scheduled to help avoid or mitigate OFO penalties if the actual load exceeded PSE&G's forecast. On Sunday, January 20, 2008, PSEG ER&T scheduled deliveries of 53,400 Dth of gas to PSE&G's stations. During that night, temperatures in the Tennessee portion of PSE&G's system dropped substantially further than what had been forecasted. Consequently, the actual gas load in that area exceeded the scheduled deliveries by 5,541 Dth, or 4,473 Dth in excess of the 2% tolerance.

In response to this situation and due to a revised, colder forecast for Monday, January 21, 2008, PSEG ER&T attempted to increase deliveries for that day. An additional 8,000 Dth of gas being delivered on Tennessee to the Transco interconnect at Rivervale NJ, for further delivery to PSE&G's Transco City Gates, and was redirected to PSE&G's Tennessee City Gates. PSEG ER&T expected that such an intra-day scheduling change would be approved by Tennessee since the Tennessee City Gate stations are upstream of Rivervale on Tennessee and are considered primary within the path of PSEG ER&T's transportation contracts. Since there would be no net change in the deliveries of PSE&G's supplies, this redelivery would not adversely impact Tennessee's system operations.

Tennessee initially confirmed the redeliveries, but on Monday night, well into the day in question, reversed their position and cut all intra-day scheduling changes. The net result was that PSE&G's actual load at the Tennessee stations exceeded the scheduled deliveries by 2,387 Dth, or 1,319 Dth in excess of the 2% tolerance. As a consequence for the two-day period, ER&T was billed a penalty of $ 5/Dth on 5,792 Dth, equating to $28,960.

PSEG ER&T met with Tennessee on several occasions following the above incident to present the case that, in the future, these specific intra-day scheduling changes should be permitted by Tennessee in light of the unique operational considerations previously mentioned. Tennessee agreed and made the required changes in their scheduling system to confirm such transactions, even on peak days when OFOs may be in effect. These changes became effective prior to the 2008/2009 winter season.

Gas Storage

PSEG ER&T's storage portfolio is largely market area based, which provides for less dependence on long haul firm transportation when demand is greatest, leading to greater supply reliability. Each storage service in the portfolio has different terms and conditions such as number of days of service, injection, and withdrawal entitlements and ratchets, and other contractual constraints. These storage services are utilized so as to even out the days of withdrawal and assure that ratchets are not triggered too early in the season, which would impact late season deliverability.

PSEG ER&T bases storage utilization on a number of factors: weather to date, maintaining storage withdrawal ratchets to assure peak deliverability, and the ability to satisfy late season demands.

In the winter, the decision is made by PSEG ER&T, and is continuously refined, as to how much daily gas will be purchased as well as how much storage will be utilized. This decision is revisited daily.

PSEG ER&T's summer plan is designed primarily around filling storage by the end of the summer at a reasonable price. Since send-out is relatively consistent, the plan is altered based on pricing changes in the market and any major events, e.g., hurricanes, heat waves. Similar to the winter, the plans are evaluated on a seasonal, monthly, and daily basis with changes made as necessary.

PSEG ER&T also has available certain peaking supplies to meet the BGSS requirements on extremely cold days. These are comprised of gas supplies from cogeneration contracts whereby the cogeneration operator uses an alternate fuel on certain days when PSE&G interrupts the flow of natural gas and this gas is used to meet the needs of the firm customers.

The quantity of storage and peaking supplies are appropriate for the demand characteristics of PSE&G's system. Contracting for peaking gas supplies from power generators is a lower cost alternative to investments in additional propane-air or LNG facilities. The following table shows the changes in gas storage and peaking supplies. These supplies are contracted to meet the service obligations to BGSS customers. The peaking supplies are comprised of contracts with power generators (Coastal/Eagle Point, Newark Bay, Virginia Power, interstate pipeline PS-6), liquid natural gas suppliers (Transco LGA and PSE&G LNG), and propane-air from PSE&G.

Between 2005 and 2009, PSEG ER&T has increased storage by 5.1%. Since 2007, the total volume of storage has remained about the same. Storage has remained about 31% of total gas supply.

Table 18-11 – Summary of Storage and Peaking Supply for BGSS

Source	Peak Day, MDTh		
	2005	2007	2009
Underground Gas Storage	*912.8*	*958.6*	*959.4*
Peaking Supplies			
Coastal/Eagle Point	55.0	55.0	55.0
Newark Bay	21.5	0.0	0.0
Virginia Power Peaking		25.0	25.0
PS-6	13.2	13.2	13.2
Transco LGA	273.3	273.3	273.3
LNG	67.5	67.5	67.5
LPA	212.0	212.0	212.0
Total Peaking Supply	***642.5***	***646.1***	***646.1***
PSE&G Firm Supply Subtotal	***2,713.6***	***2,824.8***	***2,838.2***
FTS ADCQ [1]	206.8	211.5	232.7
Total PSE&G Gas Supply	***2,920.4***	***3,036.3***	***3,070.9***
Peak Day Send-out Forecast [2]	2,894.0	2,820.0	2,743.9
Total Peak Day Capacity Requirements [3]	3,104.7	3,026.8	3,010.9
Surplus / (Deficiency)	*-184.3*	*9.5*	*60.0*

1 - Firm Transportation Service, Aggregate Daily Contract Quantity
2 - Based on Corporate Energy Forecast, Gas
3 - Total peak day capacity required to meet the Peak Day Planning Criteria

In addition, PSEG ER&T is able to dispatch supplies of LNG and LPA from gas plants owned by PSE&G on certain peak days. These supplies are for a limited number of days and are able to meet needle peaking needs.

The following table shows the summary of the volumes of gas that were produced from LNG and LPA facilities in the last three years.

Table 18-12 – LNG and LPA Utilization

Month	Burlington LNG – Dth*			Combined LPG -- Dth		
	2007	2008	2009	2007	2008	2009
January	39,906	11,995	155,925	0	0	12,921
February	140,778	51,368	42,514	47,055	20,123	34,217
March	16,077	6,084	25,330	8,786	5,889	1,384
April	5,786	7,605	6,108	0	0	0
May	5,672	10,140	5,764	0	0	0
June	8,648	12,498	5,699	0	0	0
July	8,469	6,858	5,655	0	0	0
August	4,563	7,047	8,599	0	0	0
September	7,098	5,065	10,175	0	0	0
October	10,501	13,507	9,558	0	0	0
November	6,604	8,385	5,604	0	0	0
December	11,517	6,485	7,063	10,550	5,491	8,885

* The monthly volumes at Burlington include boil off at the facility

The capacity of the Company's LNG plant is 67,500 mmbtu's/day with a storage capacity of 100,000 barrels.

The following table shows the combined storage and daily capacity of the Propane Peaking Plants.

Table 18-13 – Propane Peaking Plant Capacity

Plant	Capacity (Gal)	Daily Capacity (mmbtu/d)
Harrison	1,080,000	90,000
Central	1,140,000	90,000
Camden	600,000	32,000
Linden	900,000	-

PSEG ER&T was able to take a legacy asset that was not able to be utilized to its fullest extent and transform it to a storage asset that provided incremental deliverability. For several years, Tennessee provided a storage service to PSE&G that was 151 days in length based on maximum daily withdrawals. As a result, much of this storage capacity was not useable except during very severe winters. PSEG ER&T approached Tennessee and requested an increase in storage withdrawal and downstream pipeline delivery capacity while leaving the other characteristics of the storage untouched. Incremental deliverability was provided through the Tennessee Connexion[12] (November 2006) project.

PSE&G and PSEG ER&T Relationship

PSE&G does not have the resources, experience, or capability to critically assess, independent of PSEG ER&T, the full implications of changes in gas procurement and hedging decisions. The BGSS Services organization, an arm of the Business Analysis unit in PSE&G, is the only entity within the gas supply process that directly represents PSE&G. Their role is to provide the appropriate direction and oversight of supply hedging and hedging.

PSEG ER&T, within PSE&G Power, is responsible for energy procurement and trading. It procures the gas supply for PSE&G under a full requirements services agreement. Gas Supply is the front office, responsible for executing all of the transactions. All back office functions are performed under the direction of accounting services, which is independent of ER&T.

The Chief Risk Officer and the Risk Management organization report to the CFO of PSEG.

PSE&G's relationship with PSEG ER&T is codependent, rather than independent. PSE&G provides PSEG ER&T with the monthly and peak daily send-out forecasts. These forecasts are relied upon by PSEG ER&T in contracting for gas supplies and transportation. Knowledge of national and regional gas supply markets and financial instruments to manage price volatility rests largely in the hands of PSEG ER&T. Evidence of PSE&G's reliance on PSEG ER&T is highlighted by the fact that testimony is presented to the

[12] Response to Discovery, OC-529 – Natural Gas Supply Projects.

NJBPU by PSEG ER&T on gas supply matters on behalf of PSE&G. For example, PSEG ER&T presented the recent hedging strategy to the BPU staff.

Transfer of Gas Supply Portfolio to PSE&G ER&T

In an order dated April 17, 2002, the BPU approved the transfer from PSE&G to PSEG Energy Resources & Trade LLC[13] contracts related to the rights to purchase, transport, and store natural gas. Under the terms of the "Requirements Contract," ER&T is to provide the full gas supply requirements for PSE&G Basic Gas Supply Service ("BGSS") retail tariff customers and contract cogeneration customers of PSE&G.

In addition, PSEG ER&T purchases capacity and energy produced by each of the generation subsidiaries of PSEG Power. In conjunction with these purchases, PSEG ER&T uses commodity and financial instruments designed to cover estimated commitments for BGSS and other bilateral contract agreements. PSEG ER&T also markets electricity, capacity, ancillary services and natural gas products on a wholesale basis. PSEG ER&T also engages in off system gas sales and capacity releases to various counterparties.

The significant provisions in the Gas Requirements Contract[14] include:

- PSEG ER&T obligation to supply gas to PSE&G at the points of delivery, volumes of natural gas sufficient to satisfy:
  - PSE&G's firm obligations under BGSS.
  - The Provision of the Balancing Services.
  - PSE&G's non-firm obligations under its rate schedules for non-firm service and the non-Tariff Service Agreements except to the extent those deliveries of such non-firm supply obligations have been validly interrupted or curtailed.
- PSEG ER&T shall be the sole supplier of its full requirements of natural gas during the term of the Contract.
- PSEG ER&T provides volumes of gas and services sufficient to satisfy PSE&G's requirements under its:
  - Emergency sales services
  - Rate schedules: BGSS-RSG, BGSS-RSGOP, BFSS-F, CIG, or BGSS-I
  - Generation affiliate supply arrangement[15]
  - Non-tariff service agreements

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[13] PSEG Energy Resources & Trade LLC is the marketing arm of PSEG Power LLC ("PSEG Power").

[14] Response to Discovery, OC-482 Gas Requirements Contract.

[15] Generation Affiliate Supply Arrangement is the supply arrangement, approved by the NJBPU, whereby PSE&G was authorized to supply, on an as needed basis, dedicated intrastate natural gas transportation services for PSE&G's generation affiliate with respect to certain transferred generation facilities.

  - Balancing services
  - Cash-out provisions of PSE&G's third-party supplier requirements
  - Any new Tariffs placed into effect by PSE&G for the provision of BGSS

- PSE&G will make commercially reasonable efforts to curtail or interrupt loads under Rate Schedules CIG, BGSS-I or TSG-NF and Non-Tariff Service Agreements as coordinated by PSEG ER&T in performance of Scheduling Coordination Services.
- Upon eight hour notice from PSEG ER&T, PSE&G will provide volumes of gas up to the facilities' nameplate daily maximum volume. All gas produced from the Peak Shaving Facilities will be delivered to PSEG ER&T. PSEG ER&T will pay PSE&G for:
  - The cost of operating and maintaining PSE&G's Peak Shaving Facilities based on actually incurred costs.
  - The return of and return on PSE&G's investment in the Peak Shaving Facilities.
- PSEG ER&T and PSE&G agree to cooperate in scheduling and nominating all gas deliveries.
- The Contract will continue in effect through March 31, 2012, and will continue in effect from year-to-year thereafter, unless terminated by either party.
- Default by PSEG ER&T is the failure by PSEG ER&T on three days (whether consecutive or discontinuous) during any period of twelve months duration to meet PSEG ER&T's obligations under Section 2.1, exclusive of such failures as are attributed to events of Force Majeure or due to the fault of PSE&G. This provision was amended in March 2007 to "…the failure by PSEG ER&T on one day during any period of 12 months duration."
- Gas Purchase Contracts refer to all gas purchase contracts between PSEG ER&T and any producer, marketer or other PSEG ER&T source of gas which are deemed by PSEG ER&T, in its good faith judgment, to be necessary or useful for the purposes of fulfilling its obligation to supply gas to PSE&G.
- Each party has the right, at its own expense, to examine and audit the books, records and charts of the other to verify the accuracy of any statements or charges made under this Contract.

The Requirements Contract has been amended once. In March 2007, two amendments were made to the contract:

1. The term of the contract was extended for a term ending March 31, 2012, with an evergreen provision.
2. Article 1, paragraph 1.8, was amended defining the term "Default by Seller" to mean the failure by PSE&G ER&T on one day during any period of 12 months duration to meet its obligation to supply gas as provided in Article 2, paragraph 2.1.

PSE&G has complied with the provisions of the Requirements Contract, as has PSE&G ER&T.

The contract provides no performance provision. PSE&G has established no performance measures to assess the performance of PSEG ER&T.

The contract allows PSEG ER&T to change the gas transportation and storage portfolio with consent of PSE&G. As mentioned earlier in this Chapter, ER&T can negotiate contracts or arrangements, in its good faith judgment, to be necessary and useful for the purpose of fulfilling its obligation to supply gas to PSE&G under the Gas Requirements Contract, without notification of, or review/approval by PSE&G.

Internal Auditing

Internal auditing provides regular, independent, and objective appraisals of PSEG ER&T's gas purchasing and hedging activities; regulatory oversight is needed to protect BGSS customers.

No audits of PSEG ER&T are conducted by PSE&G. Internal Auditing Services ("IAS") resides in the PSEG organization.

The PSEG internal audits focus on operations, financial reporting, and governance processes. The audits examine ER&T's activities for compliance with laws, regulations, PSE&G policies, procedures and contracts.

Internal Auditing Services, ERMD, and business units themselves are responsible for compliance. Our interviews with the Internal Auditing and business unit managers suggested a high level of compliance.

Internal Auditing expanded its review work of ER&T during 2008, implementing audit procedures designed to detect inappropriate charges or allocations between ER&T and PSE&G.

For the 2008 and 2009 audits, Internal Audit Services (IAS) performed the BGSS program audit each year. IAS reviews accounting book entries for purchases in Gas Master and Zai*Net, book transfers, trade tickets, and journal entries to help assure costs are recorded in the appropriate segment of the BGSS program. Procedures are aimed to detect if any inappropriate transactions were recorded to the residential program (that is, costs belonging in the commercial/industrial or off-system sales program). Our review of the audit results showed no actions required as a result of these procedures.

There were no Special Control Reviews performed on any aspect of gas procurement activities during 2007, 2008, or 2009.

Review of Internal Auditing Services audits show that PSEG ER&T receive regular, internal surveillance. The following table provides a summary of the type and scope of IAS reviews.

Table 18-14 - Internal Audits[16]

Audit	Scope
2009	
Basic Gas Supply Services Costs – 2008-2009	Accuracy of costs transferred by ERT to PSE&G including accuracy and propriety of allocations.
Energy Resources & Trade Accounting Controls	Accounting controls and propriety of accounting data for financial reporting and incentive compensation purposes.
Continuous Monitoring - ERT Trading Activities	Trade ticket approvals and restricted credit transactions.
2008	
Basic Gas Supply Services Costs – 2007-2008	Accuracy of costs transferred by ERT to PSE&G including accuracy and propriety of allocations.
Energy Resources and Trade Accounting Controls	Accounting controls and propriety of accounting data for financial reporting and incentive compensation purposes.
Continuous Monitoring – Trading	System reports for on-going reviews of trade tickets, price indices, system access rights, mark to market pricing, credit.
Inter-company Billing	Inter-company transactions properly accounted for and eliminated in consolidation and cross subsidization between regulated and non-regulated affiliates.

PSE&G has a financial incentive to maximize the allocation of costs to BGSS to the extent permitted by legal requirements. As long as ER&T has a plausible basis for its allocations, PSEG internal audit can be expected to accept the allocation, even if better methods are available.

Commodity and Capacity Release

Capacity Release

PSEG ER&T seeks to release pipeline capacity in a vigilant manner at the most favorable rate. Capacity release (making unneeded firm capacity available on a term basis to third-party shippers) deals were completed on seven pipelines. The majority of the capacity release occurred on Transco (97 deals) and Texas Eastern (63).

The duration of the capacity release ranged from 1 day to 3287 days. Thirty-one deals had a duration of 30 days or less, while 49 deals had a one year duration.

In the past five years, PSEG ER&T has executed 166 capacity releases, totaling 4,560,915 mmbtu/day. Nearly 55% of the volume was released at maximum rates.[17]
[Begin Confidential]
[End Confidential] provide a summary of the capacity release deals by pipeline and year.

[16] Response to Discovery, OC-45 Management & Affiliate Audits.
[17] Response to Discovery, OC-229 – Pipeline Capacity Releases.

[Begin Confidential]

Table 18-15 - Total Capacity Release Contracts

[redacted]

Table 18-16 - Capacity Release Contracts at Maximum Rate

[redacted]

[End Confidential]

Capacity Allocation[18]

When PSEG ER&T determines that it has pipeline capacity available, which is surplus to the requirements of PSE&G's BGSS customers, including the opportunity to engage in off-system wholesale sales (the margins from which are shared with BGSS customers), ER&T can use a portion of its overall portfolio to acquire gas for PSE&G's gas-fired power plants in New Jersey ("generation gas"). In such cases, the price charged for the generation gas is equal to the weighted average cost of all the gas purchases made by PSEG ER&T for the applicable period (typically either a month or a day), including the cost of transporting each gas purchase from its respective purchase point to PSE&G's City Gate.

This weighted-average cost methodology is only used during periods when the incremental purchases of generation gas do not result in PSEG ER&T having to purchase gas supplies at locations whose gas price, plus associated transportation cost, is higher than the balance of PSEG ER&T's supplies being purchased to meet BGSS requirements.

In certain situations, generation gas needs result in PSEG ER&T having to purchase supplies, which are substantially more expensive than what otherwise would be required to satisfy the requirements of BGSS customers and off-system sales opportunities. In those cases, the total delivered costs of such incremental gas purchases are charged solely to the generation gas requirements. This insulates the BGSS customers from additional costs.

The following table shows the approximate volumes of generation gas provided by PSEG ER&T using the weighted average and incremental methods, respectively, for the last three years:

Table 18-17 – Generation Gas

Cost Methodology	Volumes, in millions of DTh		
	2007	2008	2009
Weighted Average Method	59.6	64.5	52.4
Incremental Method	12.5	22.7	25.5
Total	**72.1**	**87.2**	**77.9**

Review of Previous NJBPU Report

We reviewed the Analysis of the Gas Purchasing Practices and Hedging Strategies report dated January 15, 2009.

The Analysis of the Gas Purchasing Practices and Hedging Strategies study included a transaction-by-transaction analysis of each utility's hedging program, as well as an evaluation of risk management policies, control procedures, and organizational structure.

[18] Response to Discovery, OC-532 – Gas for Electric Generation.

The consultants also simulated an alternative program design covering the same six-year historical period in support of their recommendations for improving the utilities' hedging programs.

The central aim of the recommendations was to promote greater mitigation of acute price spikes than is currently achieved by the GDCs' hedging programs, with a goal of being more hedged in high price environments than in stable or falling price environments. The general recommendations of the study were that:

- The utilities' gas-cost mitigation programs embrace structured decision rules (which we refer to as "hedging decision protocols") that are responsive to transitory changes in prices and volatility.
- The programs feature the well-controlled use of financial options to ensure adequate participation in falling markets.

The report has four PSE&G specific recommendations:

- PSE&G should define program objectives that are explicit in terms of potential cost and out-of-market outcomes that are tolerable. (IV-R11)
- PSE&G's program should be structured so as to ensure a hedge ratio is established well in advance of delivery to pre-empt the situation of hedging precipitously during the highly-volatile portion of the curve. (IV-R12)
- PSE&G should more clearly define its Discretionary protocols/triggers, and link them to forward-looking prices as opposed to historical indicators. (IV-R13)
- PSE&G should determine its hedging program modifications on the basis of multiple simulations of varying decision rules. (IV-R15)

Our findings presented earlier in this report concur with recommendation IV-R11. PSE&G should establish measures in order to assess the performance of PSE&G ER&T.

In response to the recommendations (IV-R12) presented in the Gas Hedging Audit, PSE&G ER&T at the direction of PSE&G initiated a revised gas hedging program. For the 2010-11 winter season, PSE&G ER&T began to hedge gas for the residential customer using two methods: Non-Discretionary Method and Dollar Budget Method. The maximum annual targeted volume is approximately 70.0 bcf split evenly between the summer and winter seasons. Further, each of the two methods is to be split evenly within the seasons.

PSEG ER&T expects to use the Bollinger Band method to assess price triggers/ purchasing decisions. The method is a tool to give an indication of price movement; it cannot predict an absolute high or low price.

PSEG ER&T uses the Bollinger Band as a tool to assist in determining when it may be more advantageous to hedge a portion of the residential customer's gas supplies. The Bollinger Band method may be used by PSEG ER&T to determine its discretionary triggers and linking them to forward-looking prices.

To develop a simulation model for assessing varying decision rules that may lead to modifications of the hedging program would likely require PSE&G to outsource this work.

19. ELECTRIC DELIVERY AND OPERATIONS MANAGEMENT

Introduction and Summary

This chapter addresses PSE&G's Electric Distribution and Operations Management and includes System Operations and Maintenance, System Reliability, System Planning, Load Management, Fuel Management, Pooling Interchange and Economic Dispatch, and Smart Grid Activities.

Summary of Findings

A. System Operations and Maintenance

1. Structured operations, maintenance programs, and systems are in place to track performance.
2. PSE&G's O&M spending level per customer has tracked first quartile utilities and is below the median level.
3. PSE&G's tree-related outages have steadily decreased over the 2005 to 2009 period, indicating that the vegetation management program is effective.
4. PSE&G's Energy Utility Technology Degree Program, established in 2003, has been successful at attracting new technical hires and is endorsed by three participating unions. During 2009, this program resulted in 68 hires through mid-year.
5. PSE&G's overtime statistics have averaged between 26% and 27%, with peaks as high as 30% among certain groups. This is in line with recent findings of other large utilities, but in our opinion is endemic of the technical workforce shortfall affecting utilities across the country. In our opinion, these levels are excessive.
6. PSE&G appears to realistically plan and execute its work planning. Over the past two years the variance between planned and executed work orders has been approximately 1%.
7. PSE&G outsources or contracts a fairly consistent level of capital construction and operations workload, in line with other large electric utilities.
8. PSE&G performs maintenance and inspections in conformance with industry best practices and in some areas exceeds industry averages. Its inspection backlog is virtually zero.
9. PSE&G proactively embraces leading applications of information technology and has a set of well-maintained and integrated applications that contribute to its excellence on operations and maintenance.

B. System Reliability

1. PSE&G is highly focused on system reliability performance. The Company pays constant attention to the reliability performance of the system. One example is the daily review of outages by division and corporate management with next day follow-up reporting.
2. PSE&G has consistently maintained top of class reliability performance.
3. PSE&G was recognized by the PA Consulting Group as the winner of their National Reliability Excellence Award for its reliability performance in the years 2004, 2005, 2007, and 2008. PSE&G was also recognized by the PA Consulting Group as their Regional winner in the Mid-Atlantic Region for its reliability performance in the years 2004, 2005, 2006, 2007, and 2008.

4. PSE&G conducts its own peer survey for reliability and participates in the IEEE Annual National Reliability Survey and consistently ranks in first quartile both for CAIDI (Customer Average Interruption Duration Index) and SAIFI (System Average Interruption Frequency Index).
5. PSE&G has a well-conceived and applied emergency response capability, which includes industry best practices.
6. PSE&G employs outside assistance from mutual assistance crews as needed, but only had to call on these resources twice in the past six years.
7. PSE&G's Emergency Response Plan contains provisions for developing, recording, and acting on lessons learned following major events through a formal process.

C. System Planning and Design

1. PSE&G employs state-of-the-art techniques in the load forecasting process and adheres to the Company's internal Design Standards which, in turn, conform with the Industry Standard Specifications.
2. PSE&G closely coordinates with PJM for transmission planning and operations.

D. Construction and Operations Budget

1. PSE&G has an annual, multi-step, and multi-level corporate budgeting process, where the budgets undergo several levels of review before they are finalized.
2. Close attention is given to the possible impact on reliability due to budget changes. Corporate and division management monitor budgets and reliability from a corporate scorecard perspective and will make adjustments as necessary to meet the KPIs.
3. There were no T&D capital budget reductions over the 2005 to 2008 period; however, there were small reductions in O&M budgets over the same period averaging 2.3% annually, mainly reflecting modified scope.
4. PSE&G's capital expenditures per customer have increased slightly over the 2004 to 2008 period.
5. PSE&G has a robust project estimation protocol to ensure realistic estimates at each stage of project development. Further, the Company measures project success on the basis of schedule, scope, and budget; these metrics are part of the key performance indicators.

E. Load Management

1. PSE&G coordinates with the BPU and PJM on demand response programs and out-performed the PJM average of 118% by 5% for the 2009/2010 delivery year.
2. PSE&G is engaged in load management activities that are strategic and tactical.
3. PSE&G has expressed concern that the BPU has not fully defined the role of the utility in Demand Side Management. Also, more public awareness is desired on the state and Company goal of 20% load reduction by 2020.

F. Renewable Energy

1. PSE&G has embraced and sponsored several renewable energy solar projects to help meet the requirements of New Jersey's Renewable Portfolio Standards.
2. PSE&G also is developing a carbon abatement program to save non-renewable resources through energy saving activities offered to its customers, including home energy audits, new technologies and building retrofits to enhance energy conservation.
3. PSE&G participates in the New Jersey Economic Stimulus Program in which the Company provided $190 million to spur conservation and create green jobs.

G. Pooling Interchange and Economic Dispatch

1. PSE&G does well in ensuring NERC compliance via self-assessments and mock audits.
2. The Company has concerns that the NERC Standards and Compliance organization could become a growth oriented bureaucracy where costs begin to exceed benefits. PSE&G would like to see NERC Standards be more results or performance based.
3. The Company also sees that Smart Grid is growing and expanding and may present a cost allocation problem unless PSE&G can be assured of rate recovery for investment in Smart Grid infrastructure.

H. Smart Grid Activities

1. PSE&G's philosophy of Smart Grid is focused on reliability and is an important factor contributing to their reliability leadership.
2. PSE&G has taken an aggressive lead in Smart Grid initiatives, which can also provide benefits in the areas of safety, operations, and renewables for the customer.
3. PSE&G's focus on reliability coupled with past Smart Meter experience may cause them to lag in future opportunities resulting from new meter technology and application enhancements.

I. IT Support Systems

1. PSE&G is among the most advanced users of dedicated IT systems among large electric utilities.

Recommendations

System Operations and Maintenance

1. PSE&G should continue its proactive focus on reliability centered maintenance.
2. PSE&G should continue and consider expanding its Utility Technology Degree Program to attract additional potential technical resources on a fast-track basis to mitigate expected attrition through retirements.
3. PSE&G should consider actions to reduce the average level of overtime, particularly for field workers, without sacrificing reliability.

Load Management

1. PSE&G should engage the BPU to better define their role in demand side management.

2. PSE&G should undertake a public education campaign to help promote understanding on the requirements and impact of meeting the 20% load reduction goal by 2020.

Pooling Interchange and Economic Dispatch

1. PSE&G should engage FERC, and through this process, work toward achieving NERC standards being based on results and performance.

Background

This section details our review and analysis of PSE&G's electric operations, objectives, external interfaces, staffing, costs, budgeting, and project execution, as well as PSE&G's advancement into renewable energy, demand reduction programs, and SmartGrid.

PSE&G's Distribution and Operations Management function is focused on reliability centered operations.

PSE&G also participates in a number of benchmarking studies, including the following programs relevant to electric operations:

Utility Level

- PSE&G Peer Panel BM Study (Industry View)

Electric Delivery

- PSE&G Peer Panel BM Study (Industry view)
- Southern Company Electric BM Study (Industry view)
- PA Consulting Electric T&D BM Study (Consulting view)
- EUCG (Electric Utility Cost Group) BM Study (Association view)
- EEI Reliability BM Study (Association view)

Customer Operations

- PSE&G Peer Panel BM Study (Industry view)
- PA Consulting Customer Services BM Study (Consulting view)

Where available and appropriate, we have utilized benchmark study results to quantify PSE&G's relative position with respect to its peer companies in various areas of operations, such as reliability. PSE&G closely monitors the benchmark study results and researches and applies emergent best practices, where applicable.

System Operations and Maintenance

PSE&G manages system operations and maintenance programs with a focus on reliability. The distribution assets, such as substation equipment, poles, lines, transformers, protection equipment, mains, regulators, etc., are inspected and maintained using reliability centered maintenance (RCM) philosophy while adhering to state and national codes such as the National Electric Safety Code C2. The geographic information system (GIS) is the asset register for poles, wires and equipment, customers, and facilities. Inside plant assets are stored in System Applications and Products (SAP) software.

PSE&G has struck a balance between benefits and capabilities of systems by using the Investment Evaluation System (IES) which utilizes algorithms tied to balanced scorecard criteria.

PSE&G's operations and maintenance spending per customer over the 2004 to 2008 period is depicted in the table below. **[Begin Confidential]**

Table 19-1 - O&M Spending Levels per Customer[1]

[redacted]

Graph Key

[End Confidential] PSE&G's O&M spending level per customer has tracked first quartile utilities and is below the median level. PSE&G spends less on a per customer basis but has a relatively high level of customer density and enjoys excellent reliability statistics. Therefore, we do not take issue with these spending levels.

Vegetation Management. PSE&G employs a vegetation management program guided by state and national standards, and industry best practices:

- NJBPU's Vegetation Management Standards
- ANSI (American National Standards Institute) A300

[1] Response to Discovery, OC-57

- ANSI Z133.1
- National Electric Safety Code C2 – 2002
- Best Management Practices, Utility Pruning of Trees, 2004 published by the International Society of Arboriculture

The policy of PSE&G's Vegetation Management Program is to adhere to the NJBPU's Vegetation Management Standards,[2] to inspect and spot trim where necessary, and trim every circuit once every four years. Circuits identified as requiring trimming are scheduled to be done either through Fixed Price or under Time & Material contracts. Dead, weak species, and/or hollow trees are also identified to either be removed or to have other corrective actions taken. The vegetation management program also uses outage information coupled with GIS to target problem areas and thereby manage a RCM program while containing costs associated with vegetation management. Vegetation management work is 100% inspected for compliance to standards and quality assurance.[3]

PSE&G's vegetation management spend level and trim statistics are depicted in the table below. **[Begin Confidential]**

Table 19-2 – Vegetation Spend and Trim Level

[redacted]

Note: 2009 figures are estimates

[2] New Jersey Electric Service Rules, N.J.A.C 14-5-9.1(2008)

[3] Response to Discovery, OC-256.

Table 19-3 – Vegetation Management Miles Trimmed

[redacted]

Table 19-4 – Vegetation Management Spending Levels

[redacted] **[End Confidential]**

PSE&G's tree-related outages have trended somewhat lower over the 2005 to 2009 period, indicating that the vegetation management program is effective.

Table 19-5 – Outages by Cause[4]

Cause Description	2005	2006	2007	2008	2009
Animal	796	1,648	1,225	1,020	761
OH Circuits	805	828	847	838	838
UG Circuits	1,202	1,204	1,271	1,257	1,150
External	309	366	410	380	376
Lightning	447	452	652	575	482
Other	728	760	686	560	448
Outside Plant Equipment	462	453	478	484	502
Supply & Station Equip.	132	135	130	95	64
Tree	1,277	1,372	1,219	1,286	1,125
Weather	248	220	191	216	177
Total	**6406**	**7438**	**7109**	**6711**	**5923**

PSE&G conducts telephone-based "Moment of Truth" surveys administered by Profile Marketing Research. The survey asks a number of questions that probe pre and post-trim communication and quality of the work and company representatives.[5]

4 Response to Discovery, OC-842
5 Response to Discovery, OC-489

Workforce and Workforce Planning. Electric Delivery's headcount from 2006 through June 2009 is shown in the table below.

[Begin Confidential]

Table 19-6 - Electric Delivery Headcount[6]

[redacted]

[6] Response to Discovery, OC-220

[End Confidential] This program combines classroom instruction with technical apprentice-level training at PSEG Training and Development Centers, and was initially launched as a partnership with Mercer County Community College. PSEG employees also mentor students on the job and in the classroom. It has been endorsed by three participating unions: the O.P.E.I.U. (Office and Professional Employees International Labor Union), UA Local 855, and the I.B.E.W. (International Brotherhood of Electrical Workers).

The program consists of students taking six utility courses and completing two paid internships at the company's field locations, earning from $15.00 to $19.00 per hour. As part of the internships, seven different types of full-time entry level positions are available. The program also offers students training in safety, resume writing, interviewing and employability skills. If a student completes the associate degree, performs well in his/her internships and meets PSEG's other requirements, he/she can be considered for employment. To date, over 68 graduates have been hired by PSE&G. This program currently continues to provide diverse candidates for PSE&G's technical positions.

While the Energy Utility Technology Degree Program is successfully addressing the aging workforce in the technical trade areas, System Planning is still concerned about the aging workforce in their specific specialized engineering area. Not only does this function require an electrical engineering discipline, but also hands-on training to learn the different aspects of the planning criteria and the application tools to model the system. To achieve this, the industry best practice is to identify and train associate level engineers to execute system planning functions. This requires mentoring and shadowing by experienced engineers.

Overtime Analysis - A staffing operations analysis of Electric Delivery's major T&D bargaining unit workgroups was conducted to study overtime usage. The analysis reveals that the major T&D bargaining

[7] Response to Discovery, OC-155

unit work groups charged **[Begin Confidential]**

Table 19-7 - Overtime Percent[8]

[redacted]

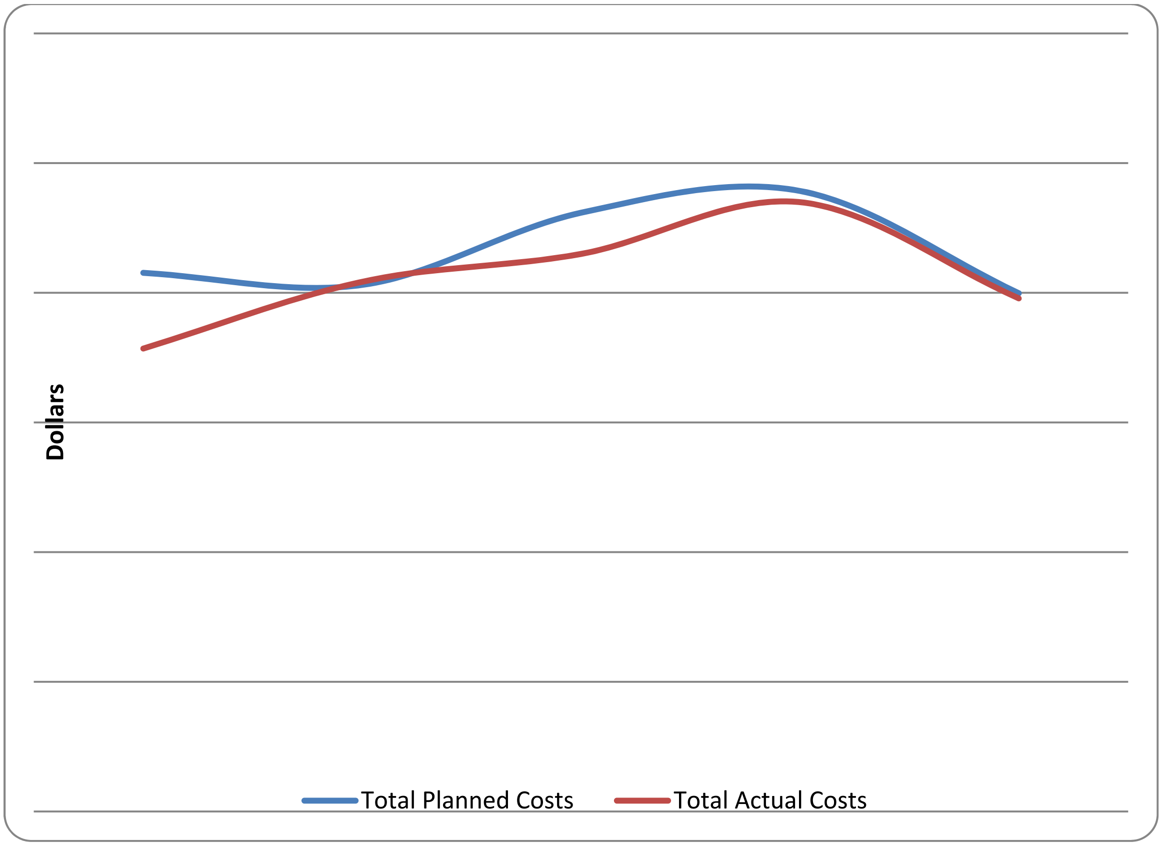
[End Confidential] Excessive individual employee overtime levels can pose a potential safety concern that should be addressed.

Work Management - PSE&G utilizes a SAP-based work management system to plan and account for electric maintenance work efforts. PSE&G also uses a computerized maintenance management system (CMMS) to define maintenance requirements based on equipment condition monitoring. Materials costs are allocated using a moving average price methodology, and crew time is assigned to the work orders through the SAP work management subsystem. Travel time is not estimated, but entered by the crews through mobile computers in the field.

[8] Response to Discovery, OC-492.
[9] Response to Discovery, OC-493.

Over the 2005 through 2009 period, PSE&G's actual versus planned expenditures track fairly well, reaching 95% over that period. In more recent years, planned vs. actual work accomplished has been in the 98% to 99% range as depicted in the table below.

Table 19-8 - Electric Delivery Work Order Performance



Outsourcing - Relative to all labor costs to support the design, construction, operations, maintenance, and repair of the electric T&D System, the following table represents the contractor portion.

Table 19-9 - T&D Outsourced Work Effort[10]

	2007	2008	YTD 09-2009
Operations and Maintenance Activities	25%	26%	25%
Capital Activities	58%	62%	64%

[10] Response to Discovery, OC-241

Operations and Maintenance levels are fairly consistent and are primarily due to tree trimming and right-of-way clearing activities. Capital levels have increased due to the contractors necessary to perform Distribution Economic Stimulus and Large Transmission projects.

PSE&G employs a "Construction Project Oversight"[11] process for contracted large project work and a "Construction/Services Vendor Evaluation Report" for smaller projects. The process is documented in a manual and covers the following verification tasks:

- Contractor project schedule oversight
- Contractor project work plan and schedule requirements
- Field status monitoring
- Inspection and verification of material supplier deliverables
- Verification of quality and quantity
- Resolution of quality and quantity issues
- Change order request
- Safety performance verification
- Invoice accuracy oversight
- Contract closeout

Maintenance Programs. PSE&G performs maintenance and inspections in conformance with industry best practices as depicted in the table below.

[11] Response to Discovery, OC-242.

Table 19-10 - Inspection Practices

		Activity	Utah	CA	PSEG	Rockland	JCP&L	Conectiv	US Navy
Substations		All - infrared inspections, I/R testing of substation bus, swi hes & major equipment	2 years	3-5 years					
	Scheduled	Inspec ion	Mon hly		Weekly	Monthly			
	Condition Based	Inspec ion	Mon hly		As needed				
Circuit Breakers		Inspect & Operate	Annual		Condi ion	4-8 Years			
Transformers		All LTC: DGA	3 month		1 year	1 year	4 years	1 year	
		DGA & oil quality for trf tank	1-3 years	1-5 years	2-4 years	1 year	2 year	1 year	2 year
		Overhaul LTC	3-8 years		Condi ion	Condition	8 years		
Regulators (3 Phs)		Overhaul - inspect contacts & filter oil	3 years	1-5 years		1 year			
Relay Packages		Test & Calibrate	1-8 years			2-4 years			
Other Equipment		All - part of monthly substa ion inspection plus:							
	Batteries	Maintenance & load test	Annual			6 mon hs			6 months
	Circuit Switchers	Inspect, Test & Lubricate	5 years		1 year	1 year			4 years
Distribution Poles		Safety Inspections	2 year	1-2 years	Condi ion				
		Detail Test & Treat	16 year	10 year	10 Year	periodic			
UG Facility Points		Detail Inspections	4-8 years		1-2 years				4 year
Local Transmission Poles		Safety Inspections	2 year		Condi ion	6 mon hs			
		Detail Inspections	8 year		5 years	as required			

Specific details for each of the major inspection elements are described in the following.

Switching Stations and Substations - Switching stations and substations are inspected both weekly, and on a time and condition basis. Major equipment in switching stations and substations are inspected per PSE&G requirements set forth in the Substation Operations Manual. This equipment includes power transformers, circuit breakers, disconnect switches, switchgear, station batteries, protective relay system components, and instrument transformers. They are maintained per requirements set forth in the PSE&G Substation Maintenance Manual and Relay Test Manual. Established maintenance standards are based on manufacturers' recommendations, industry practices, and past PSE&G experience.

PSE&G utilizes IT systems such as Computerized Maintenance Management System (CMMS), Supervisory Control and Data Acquisition (SCADA), the Emergency Management System (EMS), and the weekly station inspection data to carry out the condition-based methodology. Substation asset experts meet on a monthly basis to assess the effectiveness of the CMMS program results and may make changes to maintenance and inspection forms.[12]

[12] Response to Discovery, OC-243.

Overhead Distribution

Wood Poles

Distribution system wood poles are inspected on a ten-year cycle basis. This includes a visual inspection, a sounding test and a bore sample according the age of the pole. Preservative treatment is applied as necessary.

Reclosers

Reclosers are inspected and tested annually. All components and controls are inspected and operated as part of the annual test. Abnormalities are rectified before the summer peak load.

Infrared Circuit Inspections

Electric circuits are inspected on a four-year basis via infrared technology. The established priority criteria permit any incipient problems to be corrected before an outage occurs. An infrared inspection may also be carried out after an outage to determine the cause. Circuit visual inspections are included during the infrared inspection.

Capacitor Banks

Capacitor banks are inspected and operated before summer peak loads. They are scheduled based on a three-voltage class. The higher voltage class capacitor is inspected annually, while the lower voltage class is inspected every three years. Capacitor bank inspections also include a visual component inspection where abnormalities are corrected as necessary.[13]

Underground Distribution

Network Protectors

Network protectors and network relays are inspected on a one to two-year basis depending on the circuit application. Protectors in spot networks are inspected every year, while those in dedicated grids are inspected every two years. The network protectors are repaired at the time of inspection or scheduled for replacement if on-site adjustments cannot be made.

Underground Transformers

Network transformers are inspected on a one to two year basis depending on the circuit application. Transformers in spot networks are inspected every year while grid transformers are inspected every two years. The network transformers are repaired at the time of inspection if the repairs are minor or listed for possible replacement if major repairs are necessary.

[13] Response to Discovery, OC-243.

Automatic Transfer Switches

Pad mounted automatic transfer switches are inspected every year. This includes a visual inspection of components and control operations. Abnormalities are corrected as necessary.

Pad Mounted and Radial Transformers

Every four years, three-phase pad mounted transformers are inspected via infrared technology. Every three years, both single and three-phase pad mounted transformers undergo an external visual inspection. An internal inspection is carried out every six years on all pad mounted transformers. The transformers are repaired at the time of inspection if the repairs are minor, or listed for possible replacement if major repairs are necessary. In addition, load checks are performed every four years on all radial transformers.

Manholes

The manholes undergo inspection at the same time related equipment inspection for testing is performed. In addition, manholes are also inspected anytime underground crews enter into them to perform work.[14]

Overhead Transmission - Overhead transmission maintenance includes live-line maintenance as well as vegetation management. The live-line maintenance is performed by specialized crews, tools and equipment per the PSE&G's Transmission Live Line Maintenance Manual. The vegetation management is carried out per the New Jersey Board of Public Utilities' Vegetation Management Standards.[15]

Underground Transmission - Underground transmission inspection and maintenance is performed per PSE&G's Underground Transmission Standards Manual. System components include cable, pipe, terminations, and pressurization equipment and splice chamber enclosures. Maintenance activities and necessary repairs are tracked via a work management system. PSE&G is considering using X-ray technology to inspect splices.[16]

Inspection Backlog

PSE&G's inspection process and work scheduling appears to be very good. As shown in the table below, very few inspection backlogs are recorded, and most are cleared the following year.

[14] Response to Discovery, OC-243.
[15] Response to Discovery, OC-243.
[16] Response to Discovery, OC-243.

Table 19-11 - Inspection Backlog[17]

Inspection Element	Cycle	2005	2006	2007	2008	2009
Vegetation Management - Transmission	Annual	0	74 spans	0	0	41 spans
Vegetation Management - Distribution	4-year	n/a	52 circuits	n/a	n/a	n/a
Cable Repair	Immediate	0	0	0	0	0
Pole Reinforcement	as needed	848	166	1238	537	537
OH Line Inspections	4-year	0	0	0	0	0
Recloser Inspections	Annual	0	0	0	28	0
Capacitor Bank Inspections - 4 kV	3-year	n/a	n/a	2259	n/a	n/a
Capacitor Bank Inspections - 13 kV	2-years	n/a	4397	n/a	2387	n/a
Capacitor Bank Inspections - 26 kV	Annual	101	146	81	103	146
Automatic Transfer Switches	Annual	0	0	0	0	0
Network Protectors	2-year	n/a	29	n/a	42	n/a
Network Protectors	Annual	13	0	0	0	0
UG Radial Transformer Checks	4-year	n/a	n/a	n/a	0	n/a
Transmission OH	1-7 years	0	0	0	0	0
Transmission UG	1-4 years	0	0	0	0	0

Some inspection services are contracted through PSEG Power's Maplewood Testing Services (MTS)[18] (commonly referred to as the Lab), with 117 employees located in Maplewood, New Jersey. This facility provides specialized expertise and testing services to all the PSEG companies. These services are all of a highly skilled and specialized nature, involving all manner of testing commonly required in the utility business, including material condition, failure diagnosis, transformer oil, overheating, HV meters, etc. Infrared inspections involve the use of a special "camera" to view and collect data on lines and equipment for overheating and are part of routine inspections; transformer maintenance primarily involves testing of oil and performance of substation transformers, including failure analysis and substation maintenance: required inside plant maintenance of switchgears, relays, meters, busses, and other substation equipment. The "facilities" that the services pertain to can include all of PSE&G's inside and outside plant, lines and equipment, depending on the nature of the tests being performed. PSE&G has been using the MTS as a central source of such highly skilled testing expertise for 80 years. The MTS has records of test data for existing and retired PSE&G equipment that facilitate the evaluation of new tests. MTS personnel also have unique knowledge of the required maintenance for highly specialized electrical T&D equipment, and are available on a 24/7 basis in the event of emergencies.

The information technology (IT) systems used to support the operations and maintenance programs are as follows:[19]

- Computer Aided Dispatch (CAD)
- Computerized Maintenance Management System (CMMS)

[17] Response to Discovery, OC-652
[18] Response to Discovery, OC-734
[19] Response to Discovery, OC-244.

- Dielectric Safety Gear & Tools
- Distribution SCADA Systems
- IDRAW
- Outage Management System (OMS)
- SAP

System Reliability

Electric Reliability can be defined as the performance of an electric system to deliver electricity to customers in the amount desired within acceptable standards. The degree of reliability is usually measured by any adverse effect on electric delivery. Therefore, the measure of reliability is the frequency and duration of outages.[20] An outage is generally accepted as lasting more than 60 seconds. In general, electric reliability indices show improvement when their metrics trend downward. The indices reviewed were system interruption index, SAIFI; and the customer outage duration index, CAIDI. Briefly, their general description is as follows:[21]

- SAIFI = System Average Interruption Frequency Index (frequency of outages).
- CAIDI = Customer Average Interruption Duration Index (average duration of outages with respect to customers affected only).

CAIDI is a good indicator of the system impact for outage duration and a good indicator of the operating staff restoration performance. SAIFI, the frequency of outages, provides an indication of the condition of the system and its ability to withstand outages.

Many factors affect reliability. These factors are often captured and tracked as outage causes. These causes include but are not limited to: trees, animals, lightning, storms, equipment, crews, and other causes. Thus, programs and performance measures are created to improve reliability by frequency, duration, cause and worst performance circuit. Other subcategories and causes are tracked by companies wishing to improve in specific areas.

Many tools exist to monitor and track reliability. The most common tool used is the Outage Management System (OMS) which integrates customer reported outage calls and a hierarchy of protective devices linked to customers to "logically deduce" which protective equipment has isolated the outage. Restoration crews are then dispatched to patrol and restore the customers experiencing the outage. Databases and spreadsheets are generally used to track and trend outages, durations, causes, equipment, circuit, frequency and other attributes.

[20] The Electric Power Engineering Handbook, L.L. Grigsby, CRC Press, 2001, page 13.

[21] IEEE Std. 1366-1998: *Trial Use Guide for Electric Power Distribution Reliability Indices.*

PSE&G designs, operates, and maintains the distribution assets with a focus on reliability. They have organized all functions affecting reliability performance under one vice president to achieve the desired performance measures. The organization applies proactive, reactive, and a targeted approach to improvement projects to stay within budgets. They also apply incentive programs for employees to attain reliability goals. PSE&G uses a corporate scorecard to ensure meeting key performance indicators such as reliability.

The reliability section of the scorecard tracks metrics including SAIFI and CAIDI. The scorecard indicates if the metrics are on target and if the end of year target will be met.[22] PSE&G ranks in the top decile among utilities in the region and has been improving on all reliability metrics for the past five years. PSE&G was recognized by the PA Consulting Group as the winner of their National Reliability Excellence Award for its reliability performance in the years 2004, 2005, 2007, and 2008. PSE&G was also recognized by the PA Consulting Group as their Regional winner in the Mid-Atlantic Region for its reliability performance in the years 2004, 2005, 2006, 2007, and 2008. The following describes the reliability practices that have led to this superior performance.

PSE&G pays constant attention to the reliability performance of the system. One example is the daily review of outages by division and corporate management with next day follow-up reporting. PSE&G's managers follow-up with morning huddles with crews to go over how crew performance links up to the corporate scorecard. Other reliability practices are as follows.[23]

- Having troubleshooters and substation operators on a 24/7 schedule.
- Performing detailed weekly inspections of all switching stations and substations.
- Utilizing live-line work practices to minimize maintenance and construction related outages.
- Planning and executing storm procedures; activating the Newark-based Delivery Emergency Response Center (DERC) for major system events.
- Utilizing IT systems such as CMMS and SCADA/EMS, also integrating results of scheduled diagnostic testing, weekly inspections, cost and SAP corrective maintenance history.
- Repairing anything immediately on abnormally configured circuits.
- Funding capital equipment replacement and refurbishment program annually including transformers, circuit breakers, circuit switchers, CCVTs, relays, regulators, network transformers and protectors, underground cables and the reconductoring of overhead and underground transmission lines, etc.
- Utilizing contingency planning for extended repairs.
- Maintaining stock of critical spare equipment.
- Utilizing large high-strength overhead conductors for high main-line capacity and reliability.
- Utilizing spacer cable and covered tree-wire conductors.
- Looping all 13kV distribution system using three or five reclosers per loop.

[22] Response to Discovery, OC-218.
[23] Response to Discovery, OC-277.

- Using an Advanced Loop Scheme (ALS) with 10-12 reclosers per loop, high speed fiber optic communications between reclosers, fault recognition and isolation in five cycles or one-twelfth of a second.
- Executing an extensive vegetation management program for both transmission and distribution.
- Using animal guards on both inside and outside plant construction.
- Loading pole top transformers conservatively to reduce service failure rate.
- Performing annual system wide infrared and visual inspections of inside and outside plant facilities.
- Designing all switching stations and substations with sufficient capability to handle first contingency issues.
- Using a breaker and half switchgear scheme for the 13kV Class H substation design.
- Making extensive use of ties to other substations.
- Utilizing SCADA at the transmission and distribution levels for both inside and outside plant.
- Performing a daily 8AM Safety and Operations Conference Call involving all four Electric Divisions, System Operations, Transmission Engineering and Construction, Projects and Construction, General Office Department Heads and the Electric Delivery Vice Presidents to review significant outages from the previous 24 hours.

Reliability Trends and Benchmarks. PSE&G has consistently maintained top of class reliability performance.[24] [25]

[24] Response to Discovery, OC-315.
[25] Response to Discovery, OC-251.

Table 19-12 - Reliability Indices for 2005-2009

Public Service Electric and Gas Company Reliability Indices for 2005-2009					
	2009	**2008**	**2007**	**2006**	**2005**
	CAIDI				
Top Decile		70.70	67.70	66.60	65.00
Top Quartile		79.40	76.00	77.70	75.30
Median		102.10	101.40	101.00	101.50
Mean		112.80	112.20	118.90	108.10
PSE&G	62.97	65.45	67.65	66.44	67.04
	2009	**2008**	**2007**	**2006**	**2005**
	SAIFI				
Top Decile		0.82	0.78	0.71	0.79
Top Quartile		1.03	0.96	0.91	0.99
Median		1.23	1.15	1.16	1.17
Mean		1.64	1.17	1.18	1.25
PSE&G	0.70	0.70	0.76	0.69	0.69
	2009	**2008**	**2007**	**2006**	**2005**
	SAIDI				
Top Decile		57.97	52.81	47.29	51.35
Top Quartile		81.78	72.96	70.71	74.55
Median		125.58	116.61	117.16	118.76
Mean		184.99	131.27	140.30	135.13
PSE&G	43.88	46.10	51.09	45.71	46.02
Source: OC-0654.pdf (DR190)			PSE&G Peer Panel BM Study		

With the exception of the 2005 CAIDI, PSE&G ranked in the top decile in both frequency and duration metrics. Although the metrics fluctuate from any given year, industry gauges performance over a three-year average. PSE&G is improving or remaining consistent, but at a high-performing level over the three-year average in all metrics. It should be noted that the industry average reliability performance is showing a slight decline over the same period.

PSE&G also participates in the Institute of Electrical and Electronic Engineers (IEEE) Annual National Reliability Survey and consistently ranks in first quartile both for CAIDI and SAIFI as shown below.[26] **[Begin Confidential]**

[26] Response to Discovery, OC-57.

Table 19-13 - 2008 I.E.E.E. Reliability Survey – CAIDI

[redacted]

Table 19-14 - 2008 I.E.E.E. Reliability Survey – SAIFI

[redacted]

[End Confidential] One factor in achieving excellent CAIDI statistics is PSE&G's non-storm electric emergency response times. Since 2005, their response time has consistently improved as depicted in the table below.

Table 19-15 - Average Time to Dispatch, Minutes[27]

2005	33.8
2006	36.3
2007	30.3
2008	30.5
2009	26.2*

*Through 11/12/2009

__Outage Cause Analysis__. The outages by cause for the study period are as follows:

Table 19-16 - Electric Outages by Cause[28]

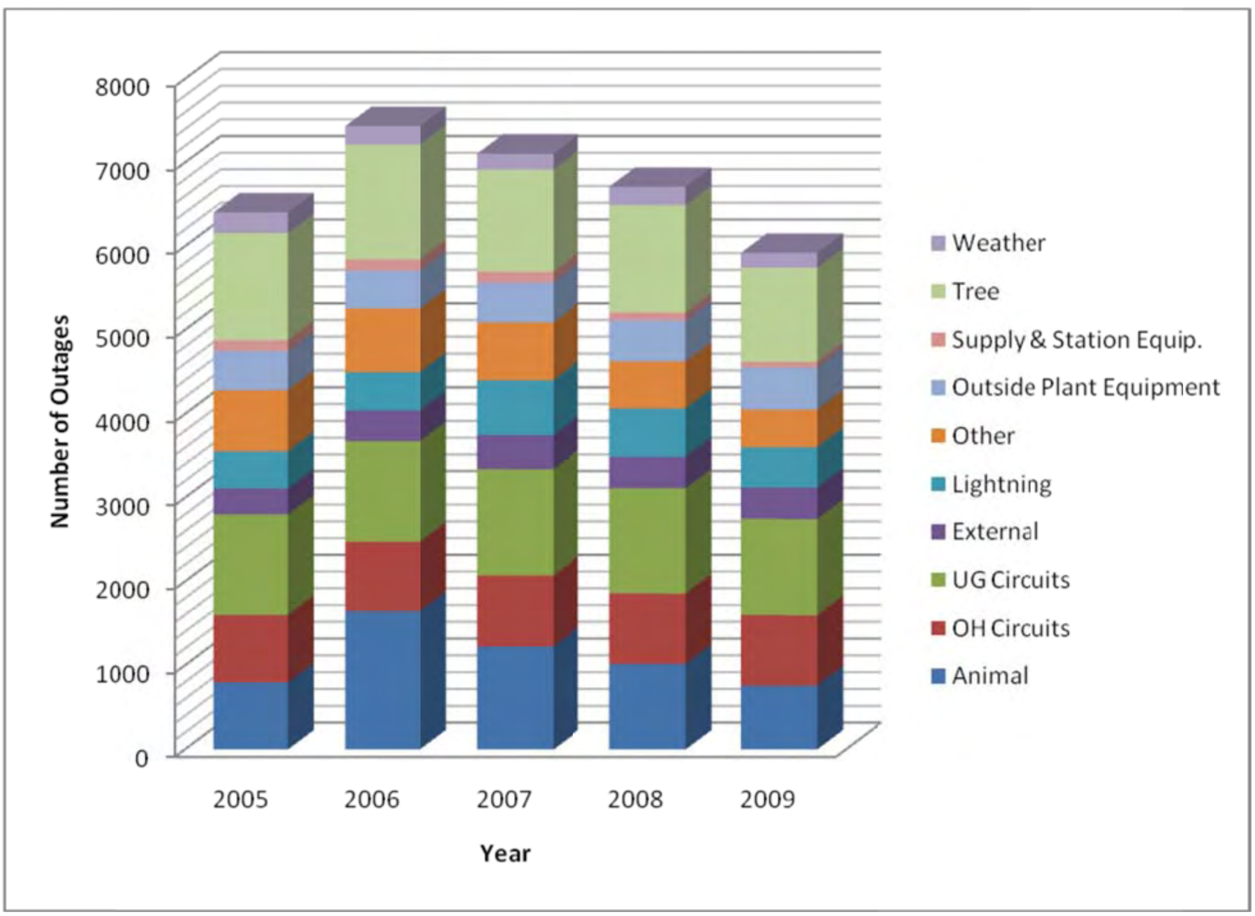
Cause Description	2005	2006	2007	2008	2009
Animal	796	1,648	1,225	1,020	761
OH Construction	805	828	847	838	838
UG Construction	1,202	1,204	1,271	1,257	1,150
External	309	366	410	380	376
Lightning	447	452	652	575	482
Other	728	760	686	560	448
Outside Plant Equipment	462	453	478	484	502
Supply & Station Equip.	132	135	130	95	64
Tree	1,277	1,372	1,219	1,286	1,125
Weather	248	220	191	216	177
Total	**6,406**	**7,438**	**7,109**	**6,711**	**5,923**

[27] Response to Discovery, OC-258.
[28] Response to Discovery, OC-299 and OC-842.

Table 19-1' - Customer Outage Hours by Cause[29]

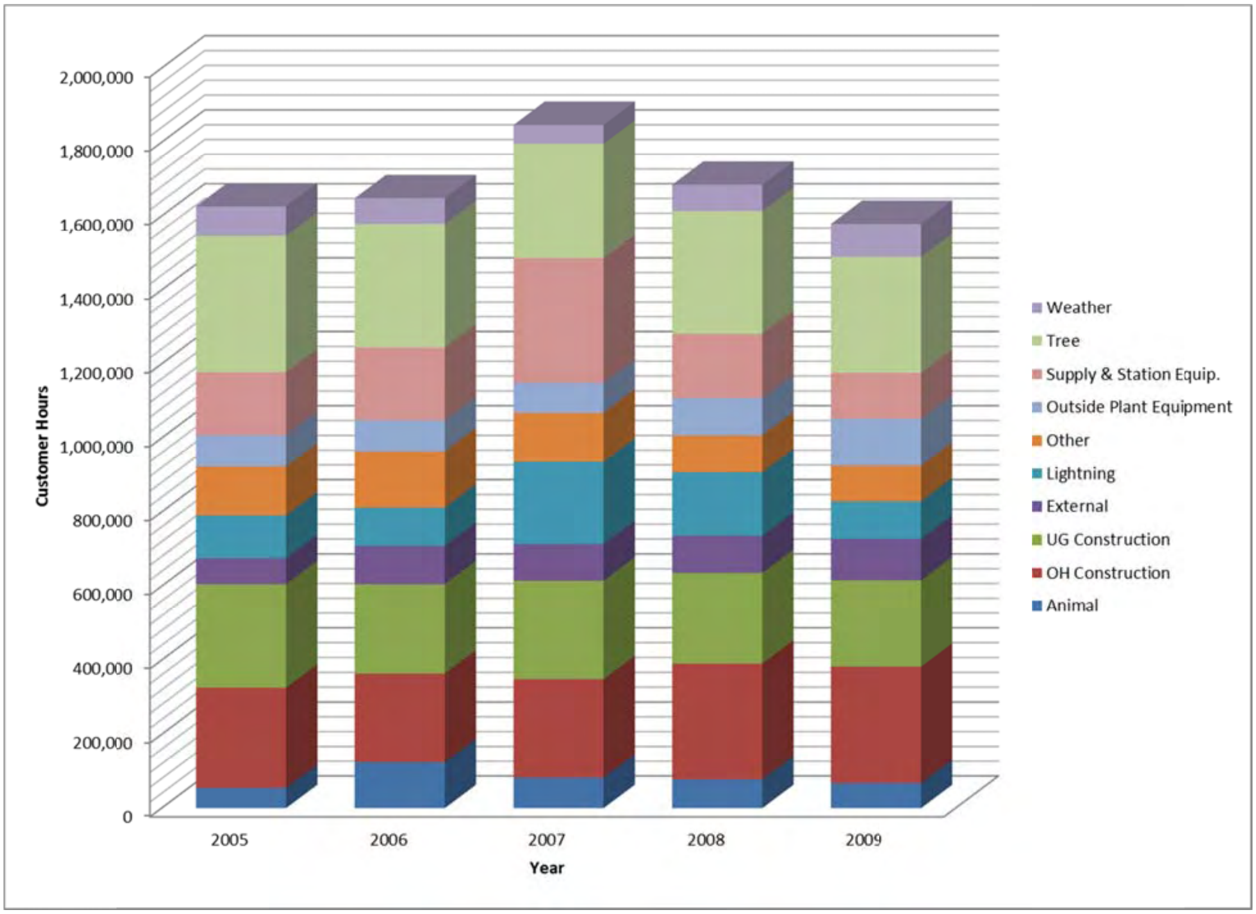
Cause Description	2005	2006	2007	2008	2009
Animal	54,527	124,716	82,081	77,695	67,372
OH Construction	271,172	238,865	266,403	312,779	314,948
UG Construction	279,941	241,808	266,229	245,267	233,274
External	69,700	103,374	98,765	100,123	112,093
Lightning	115,402	103,084	222,209	171,423	101,191
Other	132,205	151,716	132,735	99,902	96,153
Outside Plant Equipment	84,445	84,633	80,396	100,668	126,620
Supply & Station Equip.	169,823	195,899	336,857	172,690	123,954
Tree	369,631	334,297	310,150	333,015	314,466
Weather	79,214	69,725	50,855	71,263	88,634
Total	**1,626,060**	**1,648,117**	**1,846,680**	**1,684,825**	**1,578,705**

Table 19-1 - Outage Cause



[29] PSE&G Annual System Performance Report 2009.

Table 19-1) - Customer Hours by Cause



For 2009, the top four causes of outages are ranked as follo /s:

Table 19-2) - 2009 Top Ou :age Causes

Cause	2009
Tree	19%
UG Construction	19%
OH Construction	14%
Animal	13%

Compari ıg 2009 figur :s against the average of 2005 to 2008 incidents, the top improvements in outage cause mi :igation are shown in the following table, excluding the “weathe -” category. Outage causes have generally improved significantly as a result of proactive preventativ : measures.

Table 19-21 - Outage Cause Improvements

Cause	Improvement in 2009 vs. 2005-2008 Average
Supply & Station Equipment	48%
Animal	35%
Other	34%
Tree	13%

PSE&G has employed proactive measures to mitigate outages caused by underground and overhead facility failures through specifically targeted programs listed below.

Table 19-22 - Capital Initiatives to Reduce Outages[30]

Budget	Title	Description
ED-009	BUD Cable Replacements	The BUD (Buried Underground Distribution) Cable Replacement Blanket provides for replacement of Distribution outside plant BUD cable facilities due to age, and to preserve asset function and reliability.
ED-010	Delta Star Replacements	The Delta Star Replacement Blanket provides for replacement of Distribution inside plant aging and outdated Delta Star potheads. These funds will help to maintain reliability levels by avoiding 26kV outages.
ED-013	Low Pressure Gas Filled Cable Replacements	This funding provides for the replacement of poorly performing Low Pressure Gas Filled (LPGF) cable throughout the underground distribution system with newer more reliable Ethylene Propylene Rubber (EPR) cable.
ED-046	Aerial Cable Replacement Program	The Aerial Cable Replacement Program provides for replacement of Distribution outside plant Aerial Cable facilities due to age, and to preserve asset function and reliability.

As part of PSE&G's Poorest Performing Circuit Program, PSE&G is required to address annually the performance of 4% of its distribution circuits which are classified as Poorest Performing Circuits as defined by the BPU. If the performance of underground cable has had a significant impact on a circuit's reliability, causing it to be classified as a Poorest Performing Circuit, remedial actions are taken.

Storm Response

Process - The outage process[31] is initiated by either a customer calling one of PSE&G's two Call Centers and reporting the outage, or by a Supervisory Control and Data Acquisition (SCADA) alarm. As customer calls are processed at the Call Center, information regarding the outages is entered into PSE&G's Customer Information System (CIS), which then transmits this information to PSE&G's (OMS). SCADA alarms are also tied into the OMS.

[30] Response to Discovery, OC-319.
[31] Response to Discovery, OC-271.

In each of PSE&G's four operating divisions, service dispatchers, who are on duty 24/7, monitor OMS terminals for outages. They then assign a troubleshooter, or in some instances a line crew, to respond to the outage using a Computer Aided Dispatch (CAD) System. The assignments appear on the troubleshooter's or line crew's Mobile Data Terminal (MDT). A radio call is also made to the responder.

PSE&G's Geographical Information System (GIS) links the customer count associated with the outage as determined by OMS to a transformer, a fuse or other interrupting device or a circuit. Customer restoration times are tracked by OMS as they are entered into the system by troubleshooters, line crews and service dispatchers.

Emergency Crews[32] **-** The number of personnel, as of October 1, 2009, that comprises "emergency crews" within the electric distribution organization is **[Begin Confidential]**

[End Confidential] individuals could be utilized in this manner including the following: all underground classifications, all meter technician classifications, street lamp inspectors, substation mechanics and towermen / towerwomen.

During larger emergencies, PSE&G will supplement its workforce with assistance from neighboring electric utilities and/or overhead line contractors. These resources would be obtained through the Mid-Atlantic Mutual Assistance group (MAMA), the EEI Restore Power website or from a list of approved overhead line contractors.

Major Storms - PSE&G has experienced a number of major storm events over the 2005 to 2009 period, as listed below.

[32] Response to Discovery, OC-260.

Table 19-2 - Major Storm Events[33]

Year	Start of Event	Major Event	Customers Interrupted	Number of Incidents	Overall Duration, Days
2005	8/14/2005 17:00	Severe Thunderstorms	86,061	337	2.2
2005	10/8/2005 0:01	Severe Rain Storms	103,827	506	7.9
2006	1/18/2006 5:00	Severe Wind and Rainstorm	115,282	279	1.5
2006	6/1/2006 19:00	Severe Thunderstorms and Heavy Rainstorms	98,210	431	2.1
2006	6/24/2006 0:01	Severe Thunderstorms and Heavy Rainstorms	66,625	443	6.2
2006	7/18/2006 19:00	Severe Thunderstorms And Heavy Rainstorms	249,485	844	4.7
2006	9/1/2006 20:00	Gale Force Winds and Heavy Rain -Remnants of Ernesto	214,941	716	3.6
2006	10/20/2006 14:00	Strong Wind and Rain Storm	24,096	166	1.0
2007	4/15/2007 0:01	Severe Nor^Easter and Extensive Flooding	78,886	231	3.1
2008	3/8/2008 17:00	Gale Force Winds and Heavy Rain	181,336	499	2.9
2008	6/10/2008 18:00	Severe Thunderstorms	239,979	547	3.7
2009	7/26/2009 17:00	Severe Thunderstorms	144,052	616	7.2

Mutual Assistance -The EEI Mutual Assistance program is an effective program in enabling electric utilities t obtain a supplemental workforce during system e nergencies. In the past five (5) years PSE&G has had two (2) occasions where it was necessary to request a suppleme ital restoration workforce from other co npanies via t e EEI Mutual Assistance Program through its prim ry regional Mutual Aid group; the Mid-Atlantic Mutual Assistance group (MAMA). There w re no mana ement or union issues that impeded the process lue to existing company/union agreements. Below is a list of the events:

Table 19-2 - Mutual Assistance[34]

Storm Event	Request Made	Crews Arrived	# Crews
Seve e Thunderstorms August 14 -15, 2005	08/15/2005 07:30	08/15/2005 20:00	15
Seve e Thunderstorms June 10 -14, 2008	06/11/2008 07:30	06/11/2008 15:00 & 21:00	35

Mobile T ansformers[35] - PSE&G maintains nine mobile subst tions / transformers for emergency outages. PSE&G's sub tation design requires two transformers, each of which is capable of carrying the peak loa of the station. Hence, a mobile substation / transf rmer is not equired for routine maintenance. For a le gthy maintenance outage of a substation transfor ner, a mobile substation / transfor ner would be installed to maintain the integrity of the substation during the outage.

Lessons Learned - PSE&G's Emergency Response Plan contains provisions for developing, recording and acting on lessons lear ed following major events through a formal process.

33 Response to Discovery, OC-259.
34 Response to Discovery, OC-261.
35 Response to Discovery, OC-317.

System Planning and Design

System Planning involves analysis of load projects and forecasts, and capital investment planning based on criteria and economic analysis to ensure capacity will be provided to reliably supply the electric demand of present and future customers. The following details PSE&G's approach to planning involving design, planning, capital construction budgeting, as well as operations and maintenance budgeting.

Electric Supply. PSE&G was asked to describe the decision methodologies affecting electric supply, management of population related load growth, and demand side management practices. PSE&G answered that they do not perform integrated resource planning, and therefore there are no decision methodologies in place affecting these areas. Demand side management is covered in a following section of this chapter.[36]

System Design. PSE&G performs system design with a focus on reliability, and in adherence with current industry, state and federal codes and standards. In addition, PSE&G provides engineering manuals with updates and training to field personnel anytime new equipment or procedures are introduced. This is done jointly with equipment manufacturers. Quality assurance/quality control (QA/QC) is performed by frequent field interaction via monthly meetings where division and field personnel provide feedback on any standard/procedure with requests for modifications or creation of a new standard.

QA/QC is performed by the responsible engineer closing out the engineering work order to check for code compliance and project control variances. The division looks at cost variances between the engineering work order actual and estimates on a monthly basis.

The methodology used to stay abreast of changes in code and industry standards is to attend the industry conferences and meetings. Such meetings include: IEEE, Electric Power Research Institute (EPRI), Edison Electric Institute (EEI) and other research organizations. The following describes in detail the design standards and methodologies used in two categories. Inside Plant describes Substation and Switching Station projects. Outside Plant describes overhead distribution poles, wires, equipment, and underground cable and equipment.

Inside Plant - PSE&G's Inside Plant projects for transmission and distribution are designed and built in conformance to PSE&G's internal Design Standards which, in turn, conform with the Industry Standard Specifications as indicated below.[37] In addition, for transmission facilities, PSE&G complies with the technical requirements prepared by the PJM Transmission and Substation Subcommittee (TSS). These documents can be found on the PJM website at: http://www.pjm.com/planning/tsds-tech-reqs.html.

[36] Response to Discovery, OC-292.
[37] Response to Discovery, OC-282.

PSE&G, as part of the NERC (North American Electric Reliability Council) / RFC (Reliability First Corporation) requirements, has been mandated to create two conformance guidelines: FAC-008 Equipment Rating Standards and FAC-009 Equipment Ratings document. PSE&G must certify annually and submit to an audit every three years to confirm its facilities are built in conformance to the applicable standards.

All PSE&G projects undergo a rigorous process of start-up, commissioning, and final inspection.[38] PSE&G's top decile reliability performance is partly attributed to standards adherence as well as commonality of design. Regardless if the project was designed and built internally by PSE&G or by an outside firm, a final checkout and commissioning is performed by PSE&G personnel after construction. This includes a thorough inspection for adherence to both the PSE&G Green Safety Manual and the National Electrical Safety Code. In addition, division relay technicians thoroughly wire check and functionally test every control and protective circuit to verify adherence to design. A final walk through by PSE&G Engineering, Construction, and Operations management is conducted after all testing is complete to assure conformance and project completeness before energization.

Outside Plant - Overhead and underground electric distribution projects are constructed in accordance to PSE&G's Overhead Construction Outside Plant Manual and Underground Construction Outside Plant Manual. The manual incorporates design standards, codes, National Electric Safety Code, and industry standards to depict the proper practices and procedures in building electric distribution circuit projects. The field operating division engineering departments design the electric projects for the construction departments based on the standards as defined in the manuals. Engineers and construction supervisors follow the construction progress of the projects to ensure conformity with the standards in the manuals. Any abnormalities found are rectified in order to maintain compliance with the manuals.[39] Finally, asset reliability personnel track the standards and codes and revise the manuals as needed while providing training to the field personnel.

System Planning. To meet anticipated future load levels, sound utility practice requires the development of plans for the expansion of transmission and distribution facilities which may include various forms of relief or reinforcement. PSE&G uses its "Criteria for Planning the Development of the Electric System", which is on file with the FERC for defining acceptable distribution and transmission capacity, reliability and loading characteristics. First contingency outage conditions, or n-1 criteria, are used to determine the need for system expansions. Based on this criterion, reinforcement plans are developed for two, five, or ten-year periods. Load projections or forecasts are performed annually to assess load growth and new customers and to provide service reliability by providing the necessary capacity. Forecasts are prepared using specific load growth or spot load knowledge and projections based on historical load growth.

[38] Response to Discovery, OC-282.
[39] Response to Discovery, OC-282.

These load forecasts are performed for each of the system feeders and substations to develop expansion plans on a year-by-year basis. To identify system overloads, the forecasted loads are compared to the substation transformer and distribution feeder capacity. Various options of eliminating the projected overloads are investigated and the best engineering and most cost effective actions are then factored into the load and capacity analysis.[40]

PSE&G employs several methods of system expansion to resolve system overloads. Usually, the most cost effective alternatives offer the best short-term relief, while the more costly options are required to provide greater or longer term reinforcement. Examples of system expansion alternatives may include the following:

- Power Factor Correction
- Load Transfers
- Circuit Reinforcements
- Transformer Replacements or Additions
- New Substations
- New or Reinforced Supply Facilities
- Demand Side Management/Dispersed Generation

All alternatives are carefully evaluated to develop a cost-effective expansion plan.

The last step in the System Planning Process is to identify the costs and benefits of the plans and alternatives. The result is a prioritized project list ranked by legal, financial, and reliability weighted factors. PSE&G performs economic evaluations based on identified costs and benefits that provide the basis for the Distribution Business Plan. These projects are included as input to the preparation of Distribution's Five-Year Capital Expenditure Budget. Projects are prioritized using the Investment Evaluation System which quantifies costs, risks and benefits.

PJM Overview[41] - PJM Interconnection is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia.

PJM's role as a federally regulated RTO means that it acts independently and impartially in managing the regional transmission system and the wholesale electricity market. PJM ensures the reliability of the largest centrally dispatched grid in North America.

PJM's members, totaling more than 500, include power generators, transmission owners, electricity distributors, power marketers and large consumers. The company is headquartered in Valley Forge, Pennsylvania.

[40] Response to Discovery, OC-273.
[41] Source: http://www.pjm.com/about-pjm/who-we-are/company-overview.aspx.

PJM manages a sophisticated regional planning process for generation and transmission expansion to ensure the continued reliability of the electric system.

- PJM is responsible for maintaining the integrity of the regional power grid and for managing changes and additions to the grid to accommodate new generating plants, substations, and transmission lines.
- In addition, PJM analyzes and forecasts the future electricity needs of the region. Its planning process ensures that the growth of the electric system takes place efficiently, in an orderly fashion, and that reliability is maintained.
- PJM also develops innovative programs, such as demand-response initiatives and efforts to support renewable energy, to help expand supply options and keep prices competitive.

PJM Regional Transmission Expansion Plan Coordination - PSE&G cooperates with PJM in its Regional Transmission Expansion Plan (RTEP) development - PJM's RTEP identifies transmission system additions and improvements needed to keep electricity flowing to 51 million people throughout 13 states and the District of Columbia. Studies are conducted that test the transmission system against mandatory national standards and PJM regional standards. These studies look 15 years into the future to identify transmission overloads, voltage limitations and other reliability standards violations. PJM then develops transmission plans in collaboration with transmission owners to resolve violations that could otherwise lead to overloads and black-outs. This process culminates in one recommended plan – one RTEP - for the entire PJM footprint that is subsequently submitted to PJM's independent governing board for consideration and approval.

PJM Pricing Disputes - In 2006, PJM filed with the Federal Energy Regulatory Commission (FERC) a proposal that would significantly modify its regional transmission planning process for economic transmission planning. PSE&G and Power filed a protest to the PJM proposal requesting that FERC reject PJM's proposal or set it for hearing. On November 21, 2006, FERC issued an order conditionally accepting PJM's proposed changes to the RTEP for economic transmission planning. FERC directed PJM to make certain modifications to its proposal, including requiring PJM to make a compliance filing within 120 days identifying how it will weigh and/or combine the metrics it proposes for determining the net benefits of a particular project and to make a compliance filing within 90 days elaborating on the criteria it will use to determine if an alternative project is more "economic" than an RTEP project. PJM's changes to its economic transmission planning process may result in the establishment of a preference for rate-based transmission solutions to address congestion, as opposed to reliance on private investment and competitive non-transmission market solutions.

New Transmission Lines. - PSE&G had proposed two 500kV lines in the mid-2000s to alleviate expected system performance issues.

Susquehanna-Roseland 500kV line – This facility was originally proposed by PSE&G and subsequently incorporated into PJM's RTEP process. It was approved by the New Jersey Board of Public Utilities on

February 11, 2010. PJM and PSE&G had determined that through its Regional Transmission Expansion Planning ("RTEP") process, the Project is necessary by the summer of 2012 to retain reliability for the entire regional transmission grid, and specifically for New Jersey. More specifically, the Project was approved by PJM solely to address 23 projected reliability criteria violations identified by PJM in its RTEP process. Part of the order issued by the NJBPU stipulated that cost allocations must be conditioned on FERC approved cost allocations. The overall project is expected to cost between $900 and $1,200 million dollars, of which approximately $750 million represents the New Jersey portion of the project. Under the current PJM tariff, New Jersey ratepayers would be allocated approximately 14% of the project cost.

Branchburg-Roseland-Hudson 500kV Line – This project was also introduced by PSE&G and went through the PJM RTEP process. Based on more current studies and analyses, the PJM Board voted to remove this project from the RTEP and replace its intended benefits with a strengthening of two existing lines and the addition of two 230kV cables.

Construction and Operations Budget

PSE&G has an annual, multi-step and multi-level corporate budgeting process, where the budgets undergo several levels of review before they are finalized. PSE&G's Senior Leadership Team (SLT) begins the process with a series of meetings to review performance, expenditures, key performance indicators, capital project activity, and projected spending increases. As a result of these review meetings, projected income statements, cash flows, and balance sheets are developed and reviewed with the Executive Officer Group (EOG) of PSEG. Also, approved targets for capital and operating expenditures are established. The information is used by each department in PSE&G to develop approved capital and operational expenditures. The EOG normally gives final approval to the budgets in early October and the PSEG Board of Directors typically approves the budgets in mid-December.

As in the case of the capital spending, the O&M budget is subject to the same SLT reviews. The final development of the annual capital and O&M budgets are incorporated in the SAP cost planning process. The SAP cost planning process commences in the August/September timeframe and concludes in December in a typical year. [42]

Close attention is given to the possible impact on reliability due to budget changes. Corporate and division management monitor budgets and reliability from a corporate scorecard perspective and make adjustments as necessary to meet the KPIs.

There were no T&D capital budget reductions over the 2005 to 2008 period; however, there were reductions in O&M budgets as shown below.

[42] Response to Discovery, OC-264.

[Begin Confidential]

Table 19-26 - Reductions in Delivery O&M Budgets[43]

[redacted]

Notes:
[1] - Utility Operations Services (UOS) not included in 2005 amounts
[2] - 2009 Actual value is a forecast as of month end October 2009

[End Confidential]

Construction Projects.

General - PSE&G utilizes economic evaluation, budgeting, authorization, fiscal review, and project due diligence to prepare the detailed five-year capital plan. This process is used to prepare the department's next year financial plan and also to ensure the prudence of the planned projects. PSE&G's capital process employs analysis, review, approval, and monitoring on a multilayer basis.

The process begins with engineers determining where investment is most needed in the distribution system to keep it functioning at a safe and reliable level. Project managers then oversee the engineers by monitoring project progress and spending. Vice presidents ensure PSE&G optimally allocates resources and performs high-level reviews. Monitoring planned vs. actual costs, PSE&G's finance and corporate finance departments coordinate funding requests ensuring proper documentation. By way of its Utility Review Board (URB), senior management at PSE&G, reviews, approves, and monitors the capital investments of PSE&G. Similarly, senior management at Enterprises, through its Capital Review Committee (CRC) reviews, approves, and monitors the capital investments of all PSEG subsidiaries, including PSE&G.

Capital investments projects are classified into three categories by need: tariff/legal, minimum, or priority. Tariff/legal projects are generally non-discretionary and identified through external parties, and would include projects to support new service, projects dictated by environmental or regulatory requirements, or projects involving moving lines for road widening. Minimum projects are defined as needed to be done on a priority basis to avoid network impacts. Priority projects are identified, as needed, to keep the network performing at peak.

The five work types are: new business, environmental/regulatory, system reinforcement/ reliability enhancements, facility replacement, and support facilities.

Each line of business (LOB) with a capital budget uses two distinct computer applications to evaluate proposed projects and select the project that should be submitted for funding approval. The following

[43] Response to Discovery, OC-254.

evaluation tools allow each LOB to steward projects that improve operational performance while optimizing limited resources.

- The Investment Evaluation System (IES) is employed to quantify the value and risk associated with each business investment, for both specific and blanket projects. Some evaluation factors include: legal mandate, operational requirement, and the need to preserve continuity of safe and reliable basic service to customers. Impacts to the balanced scorecard are also considered. Via algorithms, all of these elements are evaluated with rigorous management scrutiny and judgment to determine the optimal portfolio combinations of work to be resourced and performed.
- The Project Economic Evaluation Model (PEEM) calculates a number of key economic indicators and possible alternatives for the project on a cost / benefit basis. PEEM calculates other metrics such as internal rate of return, net present value, and discounted cash flow values. The Levelized Annual Revenue Requirements (LARR) is the most important output.

The LOB-proposed capital plans go through a formal Utility Review Board (URB) approval process. The URB is composed of the President of PSE&G and the direct report vice presidents including: the VPs of Customer Operations, Gas Delivery, Asset Management and Centralized Services, Electric Operations and Finance. Projects needing funding in excess of 10% of approved levels must be approved by the URB. The URB reviews any emergent capital investment requests occurring during the year, and also reviews the five-year capital plan and individual project requests at a fall annual project review meeting.

After URB approval, specific capital investment projects estimated at $10 million or greater are then submitted to the Capital Review Committee (CRC) to be included in their fall review meeting of the five-year capital plan. However, the CRC also reviews any emergent specific capital investment requests of $10 million or greater that occur during the year, as necessary, and reviews increases of 10% of more for existing CRC-approved projects. The CRC consists of the following members: CFO of Enterprise, subsidiary presidents, including the president of PSE&G and the Enterprise Executive Vice President-Planning and Strategy.

The CRC advisors also have leaders of functions that cut across all Enterprise organizations such as VP and Chief Information Officer, Chief Risk Officer, VP Supply Chain Management, VP Environmental Health and Safety, VP Finance - Power, and VP Finance - PSE&G. Enterprise Corporate Planning acts as a support staff to the CRC by reviewing the project investment requests and providing assessment of the documentation quality and monthly management reports. PSE&G ensures that these meetings comply with the Company's Standards of Conduct Compliance Procedures.

The PSE&G Board of Directors must approve any specific project estimated at $100 million or greater. If funding needs for a project increase by more than 10% over approved levels, the line of business must seek Board of Directors approval for the additional funds.

While Enterprise Corporate Planning reports monthly variances and revised forecasts to the CRC, the Operating Companies and Enterprise Services Corporation supply Corporate Planning with variance explanations and updates. A mandatory project close out review is required for all specific capital projects in excess of $1 million. This review provides final cost information, financial measures, schedule data, indication of satisfactory completion of original project scope, achievement of benefits and any associated lessons learned.

The following changes to the process have occurred since 2004. From 2004 to September 2009, the CRC approved all projects, including blankets and specifics under $10 million. The URB is now solely responsible for approving specific projects less than $10 million and all blankets. Also, the threshold for spending over approved projects amounts is now 5%.[44]

PSE&G's capital expenditures per customer have increased slightly over the 2004 to 2008 period. In comparison with first quartile (higher cost per customer) and the median value from PSE&G's survey, PSE&G is spending more conservatively on a per customer basis. However, in consideration of its relatively high customer density and excellent reliability statistics, we find no fault with their capital spending patterns. **[Begin Confidential]**

Table 19-25 - Capital Spending[45]

[redacted]

Graph Key

[End Confidential]

[44] Response to Discovery, OC-267.
[45] Response to Discovery, OC-57.

T&D Major Projects Group - PSE&G created a centralized delivery major project department called Delivery Projects and Construction (DP&C) as the result of the 2008 reorganization. The DP&C has approximately 200 employees composed of Overhead, Underground, Relay craft and technical resources with a mobile workforce unit agreed to by the union. The relationship between the union and PSE&G is such that employees may cross district boundaries. The DP&C is headed by a director and six managers. Each manager leads a project team comprised of the following direct reports: inside plant, outside plant, projects, ROW/siting and permitting. There are also project control personnel who do not report directly to the project directors. Cost control responsibilities include: budget, scheduling, cash flow, and variance monitoring. The cost control positions have been internally sourced.

A detailed, multi-year implementation plan was developed for the DP&C organization.[46] The implementation plan included key requirements such as staffing, communication, logistical plans, and training. A staffing plan was developed and executed for all the P&C functional groups to establish a Project Management/Controls structure, a Mobile Construction Workforce (MCW), a work integration group and a safety oversight team. To expedite the hiring of qualified journeyman via completion of written and practical assessments, a new "test out" process was negotiated with the IBEW. All groups were adequately staffed and carrying out the management and construction of transmission planned projects by the end of 2008.

To set-up required corporate system interfaces and to meet material and vehicle support requirements, material and equipment logistical plans were developed, implemented and monitored via periodic progress meetings with utility operations support and information technology groups. Utilizing the project management approach, a functional group was set-up and staffed under a manager of transmission projects to manage large 500kV transmission projects, while a different group was put in place to manage the remaining portfolio of projects under the direction of a manager of projects. A separate project controls (PC) group with a manager – project controls lead was set-up to facilitate cost control and schedule development for the projects. A pilot was started to use the Primavera P6 scheduling tool within the project controls team to support an assessment of a wider application of Primavera P6 as the preferred portfolio management control tool in 2009.

Project Estimation - The four-stage project estimating/planning process is as follows:[47]

1.) Office Level Estimate - Less than 50% Confidence Level (CL)
2.) Study Level Estimate - 50% CL
3.) Conceptual Level Estimate - 70% CL
4.) Definitive Level Estimate - 90% CL

[46] Response to Discovery, OC-625.
[47] Response to Discovery, OC-626.

Office Level Estimate (Less than 50% Confidence Level) **-** This is a preliminary estimate used to determine a preliminary project plan with an unverified direct route. This is why a low-confidence level less than 50% is usually associated with this type of estimate, as these are little or no verified parameters. The project manager requests preliminary funding and the creation of an order to track costs incurred on a deferred basis for estimating performed in support of any potential capital project.

Study Level Estimate (50% Confidence Level) **-** The study level estimate is prepared during the study phase of the project, and is usually associated with a low-estimate confidence level of 50%. The study level estimate is used for the feasibility study, and may also be used to compare various alternatives to project engineering and execution. This estimate request requires the preparation of a scope document covering both the inside plant and outside plant portions of the project. The scope document describes the basis of the estimate. For study level estimates, a combined risk and contingency value of 50% will generally be assigned.

Conceptual Level Estimate (70% Confidence Level) - During the conceptual phase of the investment request process, the conceptual level estimate is prepared consisting of a total project cost estimate. Preliminary engineering and design have begun and a project work breakdown structure (WBS) has been initiated and defined. Site visits have already been conducted, drawings have been pulled, and the project layout has been developed, enabling a more in-depth investigation of project costs, with a confidence level of 70% for the estimate. For conceptual level estimates, a combined risk and contingency value of 30% will generally be applied to outstanding activities or commitments.

Definitive Level Estimate (90% Confidence Level) - The definitive level estimate includes the cost of the entire project, from inception, engineering, design, and material procurement to construction and close-out. This definitive level estimate is prepared when most of the project's risk-related items have been addressed and mitigated from a design to a bidding perspective. Usually, this occurs when all major equipment has been ordered, material and equipment specifications are developed and quantities calculated, land acquisition issues are resolved if new property is required, and the licensing and permitting process is proceeding favorably. For Definitive Level Estimates, an estimate-confidence level of 90% or higher is attained and a risk value of 10% will generally be applied to outstanding activities or commitments.

A phased funding approach is used for large projects. Money is requested to fund the development of the next project estimating stage. Project funding in support of the construction of a project can take place as early in the project estimate as the study stage. This may occur to secure delivery of long lead items or lock in material costs.

Cost estimates are subject to prudence audits by the Federal Energy Regulatory Commission (FERC) and PJM. PSEG files with FERC in October a schedule of project cost and in-service dates by month for the next year. FERC has a cost true-up process. If PSE&G over-collects, it must payback with interest. PSE&G is not at-risk for planning/construction costs. Budgets are comprised of a base cost and a risk and contingency cost. Projects are managed on the base cost level. Two measures PSE&G monitors for projects are cash-flow and in-service date performance. Project success is achieved by meeting schedule, scope, and budget. Four reports are used to monitor these metrics.[48]

Transmission Capital in Service Report

This monthly report is used to manage the Company's transmission assets placed in service against what was submitted in the annual FERC formula filing.

CCP Metrics - Current Capital Performance

The Current Capital Performance Metric is a monthly metric (1 month lag) used by management to evaluate the cost and schedule performance of critical capital projects against project targets. The input for this metric is the monthly Exception Report.

The metric calculation is:

Total = Schedule Performance (.30) + Cost Performance (.70) weighted by YTD spend

CPR - Capital Project Results

CPR is an overall metric used by management to measure project management effectiveness in deploying capital resources to achieve desired project outcomes. The input for this metric is the Project Close-Out Report.

Forecast Variance Report

The Forecast Variance Report is a performance measurement report that summarizes monthly forecast variances for all specific projects (those greater than $1MM) with a variance +/- $100K in a given month. The report is used to analyze variances at the resource level so that appropriate corrective action can be taken.

Contingency Management is performed using a risk review process to identify all cost factors and develop a contingency. The risks are reviewed at each stage of the cost estimate stage and adjusted. During construction the project manager cannot access the contingency funds without review and approval. Any change that impacts the project schedule or cost is via a change order. Change can result in risk/contingency funds being moved to base budget. A significant change is one that results in 5% change of a contract's value. This 5% is an internal measure.

The Work Management System (DWMS) uses hours, not dollars, to plan the work. The system uses compatible units of which 30% are controllable (inspections, system re-enforcements); and 70% uncontrollable (dictated by others, DOT, BPU, etc.). Plans are reported and viewed by annual, monthly, and weekly reports. A 10% contingency cost is added for project planning.

[48] Response to Discovery, OC-627.

Load Management

Background. The BPU directed in July 2008 that Demand Response (DR) programs be implemented by each of New Jersey's electric utilities beginning in June 2009. Per the order, the BPU established target goals for the state to increase DR by 300 MW for the first year of the program and a total increase of 600 MW by the end of the third year, of which 55% of the state target would be PSE&G's responsibility. PSE&G filed its program proposal in response to the Order and identified $93.4 million of demand response investment over a period of four years, seeking full recovery of the program costs, including a return on PSE&G's investment through rates. The BPU approved a partial settlement in July 2009 which calls for PSE&G to implement new residential and small commercial air conditioning cycling programs, targeting approximately 150 MW of demand response over the next several years. The remainder of PSE&G's proposal remains under consideration by the BPU. PSE&G's strategic load management activities are consistent with New Jersey's Energy Master Plan (EMP).[49]

Further, historically, Load Serving Entities in PJM have had the ability to meet their capacity requirements through the commitment of Demand Side Resources. With the advent of the Reliability Pricing Model, Demand Side Resources are able to participate in the capacity procurement process as either Demand Resources or Interruptible Load for Reliability. The 2009/2010 Delivery Year marks the first time PJM has required Demand Side Resources to test their capability to deliver the reductions committed to meet capacity requirements. The purpose of this report is to provide detailed results of the initial year of Demand Side Resource testing.

The test results for the 2009/2010 Delivery Year demonstrate that in aggregate, committed Demand Side Resources performed at 118% of their committed capacity values. Test results in excess of committed capacity values totaled 1,299 MW for the 7,089 MW of Demand Side Resources required to test.

PSE&G's load management performance is above average as depicted in the following table.

[49] Response to Discovery, OC-122.

Table 19-27 - Load Management Compliance 2009/2010 Delivery Year[50]

Zone	Committed MW	Over/Under-Compliance MW	Performance
AECO	61.4	14.5	124%
AEP	1,594.8	400.5	125%
APS	495.0	150.7	130%
BGE	640.0	26.5	104%
COMED	1,342.6	210.3	116%
DAY	204.4	-1.1	99%
DOM	507.7	47.0	109%
DPL	160.2	24.4	115%
DUQ	120.2	57.0	147%
JCPL	146.3	38.0	126%
METED	221.5	22.4	110%
PECO	351.3	90.3	126%
PENELEC	218.4	51.8	124%
PEPCO	109.9	34.3	131%
PPL	601.0	61.2	110%
PSEG	310.8	70.5	123%
RECO	3.1	0.12	104%
Total	**7,088.8**	**1,298.5**	**118%**

Load management is needed to maintain a reliable system and to address the challenges of demand response programs. PSE&G performs load management activities that are strategic and tactical. The tactical method used is to execute a three-step level or process approach. The first level is to employ air conditioning cycling during overloads. This activity reduces the load demand on the system on a real-time basis. The other load management processes in the tactical portfolio include voltage reduction and load shedding. Voltage reduction is the next phase in reducing load if the air conditioning cycling does not provide enough load reduction. This method was last used in 2007. Load shedding is the last resort to reduce load and was last used in 1996.

Voltage reduction is a commonly used method by utilities in the United States and the United Kingdom to reduce load during peak conditions. The process works for resistive or linear loads such as lights, small appliances and other non-motor loads.

While this method works for short periods and small voltage variations, it has drawbacks over long periods. The two major drawbacks are operational in nature. The first is a lower work output. For

[50] Source: PJM Load Management Performance Report 2009.

example, lights are slightly dimmer and water heaters or dryers have to work longer for the same level of results. Most users do not see a significant change over short periods, but the limits are clear for longer periods or higher voltage reduction levels. The second drawback is higher exposure to power quality problems during voltage reduction. Every electric installation, whether residential, commercial or industrial, will experience voltage sags during cycling of loads or starting of motors. These are normally seen as light flickers. When the supply voltage is lower, the sags seem deeper because the initial or starting voltage threshold is lower.

Renewable Energy

Solar Loan Program. PSE&G filed a plan with the BPU in April 2007 that was designed to spur investment in solar power in New Jersey and meet energy goals under the Energy Master Plan (EMP). In April 2008, this program received final BPU approval. The plan calls for PSE&G to invest approximately $105 million over two years in a pilot program to help finance the installation of 30 MW of solar systems throughout its electric service area. This is accomplished by providing loans to customers for the installation of solar photovoltaic systems on their premises. Borrowers can repay the loans over a period of either 10 years for residential customer loans, or 15 years by providing solar renewable energy certificates. Borrowers also have the option to repay the loans with cash. The program is designed to fulfill approximately 50% of the BPU's Renewal Portfolio Standard solar requirements in PSE&G's utility service.

For the reporting year 2009, 31 MWdc were installed throughout New Jersey, of which 9% or 2.8 MWdc is attributed to PSE&G's territory. With data through January 31, 2010 for the reporting year 2010, 46 MWdc of solar systems were installed throughout New Jersey of which 30% or 9.2 MWdc is attributed to PSE&G's territory.

> *These solar systems will contribute to the Renewable Portfolio Standards (RPS) targets for each reporting year as Solar Renewable Energy Certificates (SRECs) are created. For reporting year 2009, 58% of the statewide SREC obligation was met through SRECs, while the remainder of the obligation was met through Solar Alternative Compliance Payments. The Solar Loan program is contributing to closing this gap by providing financing for the completion of solar systems. The capacity under the Solar Loan program is dependent on customer demand and market conditions, and solar development had been hindered by concerns over the economy.*

The Solar Loan program is fully subscribed at this time, and it will continue to contribute towards reducing the shortfall in SRECs needed to meet SREC obligations in subsequent energy years as the systems are completed.

Solar 4 All Program. PSE&G filed a new solar initiative with the BPU in February 2009 called the Solar 4 All Program. Through this program, the utility sought to invest approximately $773 million to develop 120 MW of solar photovoltaic (PV) systems over a five-year horizon in various market segments. The

BPU issued an order approving a settlement for the program on August 3, 2009. Under this BPU Order, PSE&G will invest approximately $515 million to develop 80 MW of PV systems. PSE&G will own and operate all of the PV systems. They will be grid-connected, and PSE&G will seek to sell the energy and capacity in the applicable PJM wholesale markets.

Solar Loan II Program. PSE&G filed for a new solar loan initiative with the BPU in March 2009. Based largely on the first Solar Loan Program, PSE&G proposed to provide loans for an additional 40 MW of solar PV systems. PSE&G filed a settlement agreement with the BPU for this program on November 4, 2009. On November 10, 2009, the BPU issued an order approving the Program. The settlement contains the following provisions:

- The program will provide loans for an additional 51 megawatts of solar PV projects where individual projects in this program may not exceed 500 kilowatts.
- PSE&G's loans to developers or customers will cover about half of the cost of a solar installation project, depending on the projected output of the solar energy system and the cost of the system. The borrower will repay the principal, plus interest, over 10 years for residential customers and over 15 years for all other borrowers. This is a considerably longer investment timeframe than traditional lenders are willing to provide for solar installations.
- Borrowers of the loan will repay the loan with cash or with Solar Renewable Energy Certificates or SRECs, which are created every time the system generates solar electricity. One megawatt hour of solar generation is equivalent to one SREC, which has value in the marketplace. An SREC is a New Jersey tradable product that represents the clean energy benefits of electricity generated from a solar energy system. Under the Solar Loan II program, the SRECs are guaranteed to be valued at no less than an agreed floor price as approved by the BPU.

Carbon Abatement Program. PSE&G filed a petition for approval for a small scale carbon abatement program with the BPU in June 2008, under which the Company proposed to invest up to $51 million over four years in programs across specific customer segments. The Program is designed to support EMP goals and promote energy efficiency and consists of five pilot programs to provide energy-saving measures such as home energy audits, programmable thermostats, attic insulation, and high-energy lighting upgrades to about 30,000 residential and business customers. In a change from PSE&G's December 2007 filing, two pilot programs that had been designated only for customers in Trenton and Newark, been expanded to include other municipalities with Urban Enterprise Zones in the utility's coverage area after the first year. The Company was seeking to recover the portion of its investment that is not repaid by participating customers through an energy-based charge. The BPU approved a settlement with new rates going into effect on January 1, 2009. The Program includes the "Direct Install Program for Government Facilities", which is part if the New Jersey Economic Stimulus Funding, and will provide audits for municipal, local, county, and state government buildings. This program is designed to reduce carbon emissions by helping customers lower their energy consumption. The program will achieve this goal through the direct installation of cost-effective energy savings measures, as recommended by an on-site energy audit. The Program will provide financing of the customer's share of the project cost as a part of their PSE&G bill. PSE&G will pay for 80% of the installation and equipment costs, and the customer will be responsible for paying the remaining 20% through their PSE&G bill.

New Jersey Energy Efficiency Economic Stimulus Program. PSE&G filed for approval of an economic energy efficiency stimulus program on January 21, 2009 under which PSE&G proposed to spend $190 million to encourage conservation and create green jobs. As a direct response to a call from New Jersey's governor, this filing aimed to invigorate the economy as part of the state's economic assistance and recovery plan. The Economic Energy Efficiency Stimulus Program filing was made under New Jersey's Regional Greenhouse Gas Initiative (RGGI) legislation. This legislation encourages utilities to invest in conservation and energy efficiency programs as part of their regulated business. The new expanded energy efficiency initiative offers programs for various targeted customer segments such as sub-programs for residential homes and small businesses in Urban Enterprise Zone municipalities, multi-family buildings, hospitals, data centers, and governmental entities provide audits at no cost to identify energy efficiency measures. Under this program, customers could be eligible for incentives toward the installation of the energy efficiency measures. Other components include a program that provides funding for new technologies and demonstration projects, and a program to encourage non-residential customers to reduce energy use through improvements in the operation and maintenance of their facilities. The BPU approved this program in an order dated July 16, 2009.

As part of the Energy Efficiency Economic Stimulus program proceedings, BPU Staff requested Rutgers CEEEP to perform cost/benefit analysis on all utility proposed programs statewide, including a Participant Cost Test ("PCT"), Program Administration Cost Test ("PAC"), Ratepayer Impact Measure ("RIM"), Total Resource Cost ("TRC"), and Societal Cost Test ("SCT"). In addition, programs may be proposed by utilities and approved by the BPU to ensure that all ratepayers benefit from the BPU approved programs. This response does not address Comfort Partners, which is a NJCEP low income program that is not required to meet cost-effectiveness tests, and it does not address the Standard Offer Program.

Although renewable energy programs are not required by the BPU to be subject to cost benefit tests, the Company does quantify all benefits and projected costs and other environmental and statewide policy benefits for any program proposed to the BPU.

Stimulus projects include facility replacements, system reinforcements, and environmental/regulatory projects.[51] The overall program has earmarked projects extending from September 2009 through April 2011. The total budget is $421 million and it is targeted to create or retain 609 jobs. The budget for 2009 amounted to $98,475,000 and as of June 2009. PSE&G expected to spend the entire budget by year end. For 2009, the Program created or retained 151.5 jobs.

[51] Response to Discovery, OC-568.

Pooling Interchange and Economic Dispatch

PSE&G does well in ensuring NERC compliance via self-assessments and mock audits. NERC compliance is a function of the department where Pooling Interchange and Economic Dispatch is housed. Energy pooling interchange and economic dispatch refers to co-operation among parties or entities in development, transmission, conveyance and storage of energy in order to obtain optimum reliability of service, economy of operation, and equitable sharing of costs and benefits. The following outlines the functions that PJM provides:

PJM's Operations - PJM's staff monitors the high-voltage transmission grid 24 hours a day, 7 days a week. PJM keeps the electricity supply and demand in balance by telling power producers how much energy should be generated and by adjusting import and export transactions.

- In managing the grid, the Company dispatches about 163,500 megawatts (MW) of generating capacity over 56,350 miles of transmission lines. More than 51 million people live in the PJM region.
- PJM's experts study hundreds of "what if" scenarios and prepare to deal with virtually any event. Each variable that might affect supply and demand for electricity is carefully considered – from extreme weather conditions, emergency situations and equipment failures to the more easily anticipated cycles of hours, days, weeks, and seasons.
- PJM exercises a broader reliability role than that of a local electric utility. PJM system operators conduct dispatch operations and monitor the status of the grid over a wide area, using telemetered data from nearly 74,000 points on the grid. This gives PJM a big-picture view of regional conditions and reliability issues, including those in neighboring systems.

PJM's Market - The Company coordinates the continuous buying, selling, and delivery of wholesale electricity through robust, open, and competitive spot markets. In operating the markets, PJM balances the needs of suppliers, wholesale customers, and other market participants and continuously monitors market behavior.

- PJM's wholesale electricity market is similar to a stock exchange. It establishes a market price for electricity by matching supply with demand. Online eTools make trading easy for members/customers by enabling them to submit bids and offers and providing them with continuous real-time data.
- Market participants can follow market fluctuations as they happen and make informed decisions rapidly, responding to high prices and bringing supply resources to the region when demand is high.
- PJM has administered more than $103 billion in energy and energy-service trades since the regional markets opened in 1997.

Pooling interchange and economic dispatch functions performed by the Department of Transmission Business Strategy and reports directly to the president and COO. The department follows a functional-integrated model structure vs. a silo or vertical model. Transmission Business Strategy handles FERC (Federal Energy Regulatory Commission) and NERC (North American Electric Reliability Corporation) issues and participates in EEI meetings to voice PSE&G's interests. After 2007, NERC standards are now mandatory and require documented proof of compliance.

The goal is to find the optimal solution for the reliability of the system and the State of New Jersey, while ensuring sound cost allocations. To do this, the department must fully anticipate all costs and also consider the implication of future costs, not just the least up-front cost.

Transmission Business Strategy is fully separated from its unregulated affiliate. The department occasionally meets with the unregulated power affiliate, with attorneys present, to ensure code of conduct is followed. Transmission Business Strategy creates strategy for PSEG's EOG (executive office group) and Washington, D.C. lobbyist. The department also serves as a business services function, providing more than strategy. Transmission Business Strategy also takes advocacy positions on behalf of Transmission System Planning when confronted with congestion cost issues.

The department also oversees all NERC audits and related issues. The Performance Measures are required to be at 100% NERC compliance due to a zero tolerance requirement. This is assured by performing on-time self-assessments, spot checks, data requests, and training. Transmission Business Strategy hired an outside consultant to perform mock audits in preparation for its NERC audit.[52] NERC will audit again in three years. Due to the department's close involvement with NERC and NERC advocacy/interest groups, it has become acutely aware of an industry need for NERC ruling interpretation and best practices. The department does well in ensuring NERC compliance.

Smart Grid activities[53]

The term "smart grid"[54] refers to a modernization of the electricity infrastructure to maintain a reliable and secure system that can meet future growth. It is important to note that the smart grid vision is characterized by a two-way flow of electricity and information that creates an automated, widely-distributed electricity network. It will monitor, protect, and automatically optimize the operation of its interconnected elements – from both central and distributed generators, through the high-voltage transmission network and the distribution system, to industrial users and commercial building automation systems; to energy storage installations; and to residential consumers with their thermostats, electric vehicles, appliances, and other household devices. Development of the smart grid will evolve over several years, and, therefore, it should be thought of as the development of a "smarter" grid. The smarter grid will incorporate information technology, sensors, and distributed computing to collect and analyze data to deliver real-time information. This information will be used to instantly match electricity demand with supply from all available sources, incorporating both traditional

[52] Response to Discovery, OC-494.
[53] Response to Discovery, OC-272.
[54] Energy Independence and Security Act of 2007 (EISA 2007).4.

generation and wind, solar and electricity storage. The smart grid will enable a "just in time" balance of supply and demand at the device level. This definition of the smart grid builds on work done in both the public and private sector, including EPRI's IntelliGrid5 program, the Modern Grid Initiative6, and the GridWise Architecture Council. These significant efforts have developed and articulated the vision statements, architectural principles, barriers, benefits, technologies and applications, policies, and frameworks that help define what the smart grid is.

Potential smart grid benefits are categorized into the following five types. The energy assurance benefits are emphasized below. These benefits describe the vision of the fully developed smart grid; actual benefits will be a function of selected smart grid applications and investment levels.

Power reliability and quality. The smart grid provides a reliable power supply with fewer and briefer outages, higher-quality power, and self-healing power systems through the use of digital information, automated control, and autonomous systems. The smart grid is resilient, but when an outage does occur, it recovers faster in emergencies and limits the extent of outages.

Safety and cyber security benefits. The smart grid continuously monitors itself to detect unsafe or vulnerable situations that could detract from its high reliability and safe operation. Cyber security features need to be built into all systems and operations, including: physical plant monitoring, access control for confidentiality, integrity, and privacy protection of customer data.

Energy efficiency benefits**.** The smart grid is more efficient, reducing energy consumption, peak demand, and energy losses in transmission and distribution systems. Such efficiencies can help to defer the construction of new centralized generation plants to meet electricity demand. An efficient grid is a more resilient grid. Diverse supply and demand-side options provide operational flexibility. Less dependence on supply-side resources provides increased resilience.

Environmental and conservation benefits. A smart grid will aid in reducing greenhouse gases and other emissions by managing the network to access efficient and low-emission energy sources, reliably integrating variable renewable energy sources, and enabling the replacement of gasoline powered vehicles with plug-in electric vehicles. Integrating diverse supply options increases the resiliency of the grid.

Direct financial benefit. The smart grid offers economic benefits. While smart grid developments require capital investment, programs must be designed so that benefits outweigh costs over a suitable time period. Customers will have pricing choices and access to energy information to manage energy use for financial benefit. Entrepreneurs will accelerate technology introduction into the energy generation, distribution, and storage markets.

PSE&G's philosophy of Smart Grid is focused on reliability and is an important factor contributing to their reliability leadership. An example is the Advance Loop Scheme (ALS) used to segment outage, which lessens the impact to customers. In PSE&G's densely populated territory, current Smart Meter technology may not be the best investment at this time as it is a system that could change quickly and provide only a small return on investment. PSE&G first considered Smart Grid five years ago. Smart Meters were also considered five years ago but Time of Use (TOU), for example, was not well received by customers. On the other hand, ALS provides significant reliability improvement and is part of rate base. PSE&G's smart grid was denied American Recovery Act approval, but is moving forward in any event.

The following describes PSE&G's Smart Grid Programs that also serve as a backbone for any future Advanced Meter initiatives that PSE&G may develop.

- **Advanced Loop Scheme – Substation Distribution Automation**
  The Advanced Loop Scheme (ALS) technology uses vacuum switches that are pole-mounted and include smart relays and substations smart relays, all linked together with high speed fiber communications to reduce clearing time during faults. This smart scheme mitigates customer impact by segmenting circuits into smaller groups. This infrastructure will also create a fiber optic network between substations, call centers, and dispatchers as it is expanded through the state. PSE&G's current plan is to install this technology on 120 circuits over the next few years. This approach will be applied throughout PSE&G's territory as required to improve customer reliability, always focusing on the poorest performing circuits first. In the next four years, PSE&G expects to invest approximately $126 million in the ALS project.
- **Underground Network Monitoring**
  This project will utilize a fiber optic communication similar to the above ALS system, while it builds on a pilot project at Newark Liberty International Airport with funding support from EPRI. A state-of-the-art network monitoring system for critical underground components located in vaults and manholes will be developed and implemented using infrastructure and cyber security best practices. Proactive identification of equipment failures and disturbances without the need for manual inspections will also be accomplished. Faults will be located more easily reducing the time for restoration using this technology. All information shall be centralized for analysis and for development of proactive maintenance practices. Over the next two years, Underground Network Monitoring will be expanded to cover Newark, New Brunswick, Paterson, and Trenton.
- **Green Circuits**
  Together with EPRI and other utilities, PSE&G is participating in a project focused on reducing losses in distribution system circuits. Circuits will implement optimal VAR reduction employing switched capacitors, voltage control, targeted equipment changes (efficient transformers), and targeted design changes (reconductoring or reconfiguring). In addition to lowering losses on the circuit, voltage control on a green circuit can better manage end-use customer consumption. Also, best practices, lessons learned, and cost/benefit analysis will be some of the benefits shared with the industry.

- **Synchrophasor Project Initiative**

  The Smart Grid Synchrophasor Team was formed for the purpose of identifying and obtaining federal funds for synchrophasor[55] initiatives in the PJM footprint to aid in alerting disturbances on the transmission grid and facilitate the integration of renewable energy sources in different market environments. PJM and its Transmission Owners (TOs), of which PSE&G is part of, filed an application for matching federal stimulus funds for the deployment of Phasor Measurement Unit ("PMU") devices as well as Phasor Data Concentrators ("PDC") throughout the PJM footprint. If successful in this application, as part of the PJM team, PSE&G has agreed to upgrade two PMUs and to install four other PMUs as well as a PDC in Newark over the course of two to three years.

PSE&G has taken an aggressive lead in smart grid initiatives which can also provide benefits in the areas of safety, operations, and renewables for the customer. Specific benefits for each of these categories are summarized below.[56]

<u>Safety</u>

- Detect hazardous environments before a worker enters the space.
- Reduce risks of entering customer premises for meter readings or service shut- offs through AMI.
- Reduce arc flash exposure and in hazardous locations through use of robotic control devices to repair or replace equipment.

<u>Operations</u>

- Implementation of proactive maintenance practices.
- Improve operational efficiency by detecting failures sooner.
- Improve electrical efficiency by reducing system losses.
- Improve asset utilization through load management and new circuit control designs like advanced loop scheme.
- Improve ability to detect energy theft.

<u>Green</u>

- Enable integration of renewable generation, such as PV and wind.
- Enable the adoption of plug-in vehicles.
- Enable electrical storage by intelligent storage management.

<u>Customer</u>

- Opportunity to link supply with demand, giving customers choices in managing their energy usage.

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[55] A synchrophasor provides real-time measurement of electrical quantities from across a power system. Source: http://www.selinc.com/synchrophasors/

[56] Response to Discovery, OC-272.

- Opportunity to control loads, peak energy use, and integration of distributed renewable generation technologies.
- Knowledge quantifies energy savings choices.

Challenges

- Understanding Smart Grid development in industry.
- Meeting energy goals.
- Workforce retention.

IT Support Systems

PSE&G is among the most advanced users of dedicated IT systems among large electric utilities. They have made significant improvements over the past ten years and most systems are integrated to promote efficiency and accuracy. The IT systems used to support planning, operations, maintenance, capital projects, and reliability functions are described in the following:

Aspen. The ASPEN system is utilized to perform comprehensive circuit breaker short circuit analysis including substation bus totals, breaker duties, and the identification of overstressed breakers on the transmission and distribution systems. This permits the Company to properly design the system for current and future requirements as well as supporting reviews of equipment efficiency.

Computerized Maintenance Management System (CMMS). Collects and centralizes equipment nameplate, maintenance, operational, and diagnostic data in order to maximize the effective use of maintenance resources for Inside Plant assets through the application of equipment condition monitoring. Condition monitoring and proper triggers identify the need to perform maintenance based on actual equipment condition, and reduces scheduled maintenance and device failures. The CMMS is an integration of existing work management, supervisory control and data acquisition (SCADA) and lab systems for Inside Plant assets.

Distribution SCADA System. The Distribution System Control and Data Acquisition (SCADA) foundation is comprised of four independent systems each located within PSE&G's four division headquarters. In total, these systems communicate and gather information from over 1,900 locations throughout the distribution service territory. Approximately 40,000 digital status points and over 46,000 analog values are gathered on an exception basis.

Geographical Information System (GIS). GIS is a combination of computer software, hardware, and data that links geographic data (where things are) to descriptive information (what things are). GIS is the asset register for transmission and distribution facilities and it is the foundation for the OMS application. The GIS system is updated daily and circuits are exported nightly to OMS. The electric connected model with the customer to transformer information is required by the OMS application to enable intelligent predictions of customer outages.

IDRAW. IDRAW is a graphical user interface to model simplified sub-transmission networks and simulate actual circuit operations to provide power flow and voltage analysis. The IDRAW system is similar to Power System Simulator for Engineers (PSSE) on a limited basis for quickly modeling changing operating conditions.

Investment Evaluation System (IES). The Investment Evaluation System (IES) provides extensive demographic information and performs relative cost / value analysis for all proposed utility investments. In addition to providing financial evaluation for proposed investments, IES provides the process and system framework for project managers to identify benefits of performing, risks of not performing and all relevant assumptions for specific and blanket investments. Based on the information provided, the process is used to assist selection and deferral optimization decisions among proposed investments within anticipated budgetary constraints for the periods being evaluated.

MV-90 Remote Metering. The MV-90 Remote Metering System provides data of substation transformer loading for all major distribution substations. In addition to being a data warehouse for transformer loads, the MV-90 has multiple reporting capabilities including tabular and graphical load data.

MANTIS. Mantis is a free popular web-based bug tracking system. It is released under the terms of the General Public License (GPL). Mantis has been implemented with System Reliability and System Operations to manage all NERC CIP required change management and other reporting requirements.

Outage Management System. The Outage Management System (OMS) uses trouble jobs generated from calls to PSE&G's customer system and status events from the Supervisory Control and Data Acquisition (SCADA) system to identify electric distribution service interruptions that occur during normal, emergency, and storm conditions. The OMS determines the most likely device that operated based on PSE&G's connected model. Calls are grouped using a sophisticated grouping algorithm that takes into account the nature of the call (call type and clue code) and number of calls downstream from a device. OMS includes Pragma Views to allow for modeling of events and facilitate the grouping of calls.

Power System Simulator for Engineers (PSSE) . The Power System Simulator for Engineers tool is used to model transmission, sub-transmission and substations to determine anticipated power flow and voltage conditions under multiple system scenarios. The system indicates potentially overloaded lines and transformers as well as abnormal or unacceptable voltage levels.

Production Cost Modeling (PROMOD IV). Provides integrated production costing and transmission planning capabilities to assist in evaluating the operating cost impact of changes to supply or demand.

Project Economic Evaluation Model (PEEM). The Project Economic Evaluation Model is used to identify utility financial data for prospective projects and to economically compare alternatives. The model takes into account capital cost, O&M cost, anticipated facility life, depreciation patterns, and other facility characteristics.

Rating & Impedance System. The Rating and Impedance Program records facility details for all 26kV and 69kV circuits and calculates net circuit impedances and identifies capacity limitations for each line.
SAP

SAP is the system utilized for financials, HR, material management, time data, customer data, billing, and work management. It is also the official record of electric delivery substation facilities including all detailed data (nameplate, ratings, size, manufacturer, model, etc.) required to accurately track and manage the asset. Non-emergent work, such as new business, inspection, corrective maintenance, system reinforcement, and relocation is planned in SAP. The planned and actual labor, material, and financials are captured in SAP.

SAP Mobile App. SAP based work scheduling and mobile data terminal application used for scheduling, execution and completion of SAP customers system generated appliance service business and electric meter work.

Substation Forecast Analysis System (SFAS). The Substation Forecast and Analysis System is used to forecast substation loads, compare load to capacity, identify overloads and model relief measures based on pre-selected scenarios. The SFAS also provides historical records of substation loads, load transfers and other reference information.

WinTRIS. Safety Tagging and Outage Management System. This application is used by Transmission planning to manage all lockout/tag out associated with transmission related outages. It also provides ESOC (Electric System Operations Center) with a centralized operator logging function.

20. Gas Delivery and Operations Management

Introduction and Summary

This chapter addresses PSE&G's Gas Distribution and Operations Management and includes the following sections: System Operations and Maintenance, System Reliability, Gas System Capital and O&M Costs, System Planning & Design, and Load Management. Individual topics addressed include: asset makeup and age as well as conformance of standards to federal codes, leak history, and various gas facility replacement programs, required maintenance programs and management systems, adequacy of support systems to maintain the integrity associated with the gas distribution and transmission system, reasonableness of capital and O&M costs, planning, construction projects, construction budget and load forecasting.

Summary of Findings

A. System Operations and Maintenance

1. Overall staffing for PSE&G's Gas Delivery operations' organization at the end of each year has been fairly constant, averaging 2,012 employees.
2. There is no other US utility with more cast iron/ductile iron in their gas distribution system than PSE&G with 4,342 miles or almost 25% of its system being cast iron.
3. In PSE&G's gas distribution system, a significant portion - 539 miles or 12.4% of cast iron, operates at a pressure above utilization pressure.
4. PSE&G has performed well in delivering its commodity product safely to its customers. The Company has not had to file a PHMSA incident report since 2005.
5. PSE&G's gas distribution system is older than most of the distribution systems in the U.S. Nationally, less than 40% of all mains and 33.3% of the services, as compared to about 47% of PSE&G's mains and 44% of its services were installed prior to the Federal Pipeline Safety Regulations being enacted.
6. Short sections of cast-iron pipe connected to 12" and larger mains and operating above utilization pressure are excluded from a formal replacement program. While this exemption may be precluded on the basis that the shorter lengths result in lower risks and higher per foot replacement costs, their pressure and proximity to joints is a concern.
7. The Company lacks defined goals for achieving total replacement of cast-iron mains. Some of the cast iron in PSE&G's system in already 120 years old. Conceivably, based on the present rate of replacement, PSE&G could possibly expect some of its cast iron to last as long as 195 years from its original date of installation.

8. PSE&G has well-structured and defined maintenance programs for its gas distribution facilities and the KPI's used are more detailed then is commonly found and represent a leading industry practice.
9. PSE&G conducts a number of maintenance/inspection activities or practices to help ensure the reliability and safety of its system which exceed regulatory requirements.

B. System Reliability

1. PSE&G's Gas Delivery Business uses the ratio of gas leak reports per mile of main and service and cast-iron breaks per mile to define the reliability of the distribution system.
2. The key to distribution system integrity for PSE&G is a strong focus on inspecting, maintaining, and replacing the cast iron and bare steel systems.
3. Leakage rates compare favorably to the companies with relatively similar main systems, but PSE&G main leakage rates are nearly twice the national average when compared to utilities with newer distribution systems.
4. Leakage rates for services compare favorably to the companies with relatively similar main systems as well as those with newer distribution systems.
5. The overall leak trend for PSE&G is sloping slightly downwards, meaning slightly less leaks are being encountered each year.
6. Cast iron is being replaced at a rate Gas Delivery forecasts will allow the annual break/mile rate to stay close to first quartile performance when compared to the benchmark panel.
7. The peer panel of 30 utilities, to which PSE&G compares itself to, has only one utility with an extensive amount of cast iron in its distribution system, providing limited assurance regarding first quartile performance.
8. The Company has done a good job reducing its backlog of open leaks to be repaired by reducing the backlog in each of the last six years except for one.
9. PSE&G's inspection, maintenance, and replacement programs have been consistent with its philosophy of managing its cast iron and bare steel systems to achieve first quartile performance when compared to a peer panel of utilities.
10. The pipeline integrity management program has met the regulatory assessment and reporting requirements, while discovering a number of anomalies.
11. The distribution integrity management program will need to be developed consistent with the final rule which establishes requirements for a written program by August 2, 2011.

C. Gas System Capital and O&M Costs

1. PSE&G has an annual, multi-step and multi-level corporate budgeting process, where the budgets undergo several levels of review before they are finalized.
2. Close attention is given to the possible impact on reliability due to budget changes. Corporate and division management monitor budgets and reliability from a Corporate scorecard perspective and will make adjustments as necessary to meet the KPIs.
3. There were no gas T&D capital budget reductions over the 2005 to 2008 period; however, there was a small half a percent reduction in the 2008 O&M budgets to offset unfavorable weather impacts.
4. PSE&G's capital expenditures increased in 2009 and 2010 due to accelerating replacement projects as a result of funding by the New Jersey Economic Stimulus Program.
5. Cost per foot of replacement main and service installations are consistently well above the median for the peer panel PSE&G compares itself to. This high-cost ranking is consistent with the urban/suburban geographic area Gas Delivery serves.
6. When capital costs are compared on a per customer basis, the Company consistently ranks well below the median of the peer panel. The reason for this is directly attributable to the high customer density PSE&G enjoys on its system.

D. System Planning and Design

1. System designs are performed with a focus on reliability and in adherence with federal and state codes and where the codes do not agree, the more restrictive regulation applies.
2. Quality assurance or verification of design standards and codes for gas projects include: use of the Gas Delivery Design Manual by design engineers, use of the Gas Delivery Gas Distribution Standards Manual by field personnel, Operator Qualifications or OQ Plan certification and frequent field interaction.
3. PSE&G prepares a detailed five-year capital plan incorporating economic evaluation, budgeting, authorization, fiscal review, project due diligence and review.
4. A centralized delivery major project department was created in 2008 for both gas and electric called Delivery Projects and Construction.

E. Load Forecasting and the Gas Systems Operations Center

1. Gas procurement and supply is managed by PSE&G, the regulated utility. However, PSEG Energy Resource and Trading, a non-regulated entity reporting to Public Service Enterprise Group, performs the actual gas supply procurement.
2. Load forecasting reports with various time horizons are prepared by Electric and Gas Sales and Forecasting group and the Asset Management group within Gas Delivery. Respective reports are complementary to the gas procurement and system design effort.

Summary of Recommendations

1. Develop a program that prioritizes the replacement of all short sections of cast-iron pipe operating above utilization pressure. The program should have a definitive start and end date consistent with prudent distribution system risk management.
2. Conduct an in-depth study to explore the benefits of accelerating its cast-iron replacement program. The study should be accompanied with an assessment of possible regulatory cost recovery mechanisms. The final study along with its underlying assumptions should be formally presented and discussed with the New Jersey Board of Public Utilities.
3. Expand the makeup of the Peer Panel Benchmarking companies to include those with greater amounts of cast iron remaining in their system. This would permit a more balanced assessment of performance in this critical area.

Technical Analysis

Background

This section details our review and analysis of PSE&G's gas operations, objectives, staffing, organization, maintenance practices, costs, budgeting, and project execution. In particular, we reviewed the age of PSE&G's distribution system and its cast-iron replacement program.

PSE&G is a highly automated utility with numerous Information Technology (IT) systems in place to aid in optimization of its operations and response capabilities. The systems used by Gas Delivery gas are discussed in detail in a later section of this report.

PSE&G sponsors a benchmarking study referred to as The Gas and Electric Peer Panel Benchmarking Study - Gas Delivery. Where available and appropriate, we have utilized benchmark study results to quantify PSE&G's relative position with respect to its peer companies in various areas of operations, such as reliability. PSE&G closely monitors the benchmark study results and researches and applies emergent best practices, where applicable.

The balance of this section details our review, analysis, findings, and recommendations of PSE&G's gas operations.

System Operations and Maintenance

Gas Delivery Size, Organization and Staffing. The gas operations of PSE&G are extensive with respect to number of customers served. If PSE&G were a stand-alone gas company, it would rank 11th nationwide based on the number of customers. The below table shows the number of gas customers and respective gas operating revenues for both PSE&G and the larger gas companies.

Table 20-1 - 2009 Top 11 Largest Gas Distribution Companies per Number of Customers

Public Service Electric and Gas Company 2009 Top 11 Largest Gas Distribution Companies per # of Customers			
Rank	Name of Company	Number of Customers	Operating Revenues $(000)
1	Southern California Gas Co.	5,580,000	3,355,000
2	Pacific Gas & Electric Co.	4,300,000	3,890,000
3	Centerpoint Energy Southern Gas Ops	3,992,266	5,632,927
4	National Grid	3,491,719	6,166,566
5	Atmos Energy Corp.	3,164,176	2,841,820
6	AGL Resources Inc.	2,265,083	1,481,535
7	Nicor Gas	2,176,200	2,140,797
8	Oneok, Inc.	2,060,653	2,177,622
9	Xcel Energy	1,880,557	1,865,703
10	Southwest Gas Corp.	1,800,000	1,791,395
11	Public Service Electric & Gas/Gas Del.	1,740,000	2,764,661
Source: Pipeline & Gas Journal - 30th Annual 500 Report			

PSE&G's Gas Delivery operations organization is geographically located in three operating regions: Northern, Central, and Southern. Within these regions are 12 gas distribution headquarters and 2 sub headquarters. The distribution headquarters are: Oakland, Oradell, Clifton, Orange, Harrison, Jersey City, Summit, Plainfield, New Brunswick, Trenton, Burlington, and Audubon.[1] In addition, PSE&G operates 62 natural gas metering and regulating stations supplied by interstate pipeline companies, all located within New Jersey.[2]

Within PSE&G Gas Delivery, the Gas Asset Management and the Gas System Operations & Technical Services departments are responsible for PSE&G's gas compliance/reliability performance. Asset Strategy is responsible for growth, reliability, capital needs for new business, and regulatory and compliance via state-wide programs. Planning and Design is responsible for allocating resources and contractor workforce, budgets, investment reports, monitoring training, and variances between actual and plan.

Staffing for the region/division locations and the direct support organizations of Gas Delivery Support, Metering and Regulating and Gas Systems Operations Center (GSOC) is summarized in the table below:

[1] Response to Discovery, OC-210.
[2] Response to Discovery, OC-211.

[Begin Confidential]

Table 20-2 - Public Service Electric and Gas Company Gas Delivery Headcount

[redacted]

[End Confidential]

What follows is a detailed look at how PSE&G manages their gas delivery system in the areas of system operations and maintenance, system integrity, system planning, and load management.

Distribution Assets and System Statistics. PSE&G operates and maintains 17,612 miles of gas distribution mains in New Jersey's densely populated corridor, serving over 1.7 million customers in a 2,600 square mile service area, which runs diagonally across New Jersey. PSE&G's territory contains approximately 70% of the state's population, the largest six New Jersey cities, and approximately 300 suburban and rural towns and communities.[3] Nationally, they rank 22nd and 11th in miles of main and customers served, respectively. Consequently, PSE&G has a high number of customers per mile of main and actually ranks fifth nationwide in system density. These statistics, along with additional distribution system assets and related statistics, are shown and ranked nationally in the following table.

[3] Response to Discovery, OC-211.

Table 20-3 - Public Service Electric and Gas Company Corporate Data

Public Service Electric and Gas Company Corporate Data		
Metric	**Value**	**Rank**
Total Customers	1,742,029	11
Total Deliveries to End-Users (Mcf)	333,179,201	13
Residential Share of Total Deliveries	40.60%	49
Total Sales Deliveries (Mcf)	201,124,166	11
Transportation Share of Total Deliveries	37.80%	50
Residential Sales Revenue ($/Mcf)	$14.68	53
Commercial Sales Revenue ($/Mcf)	$12.73	49
Use Per Customer (Mcf/Yr)	191.3	45
Use Per Residential Customer (Mcf/Yr)	85.4	31
Use Per Commercial Customer (Mcf/Yr)	853.5	11
Total Miles of Main	17,612	22
Miles of Main - Cast Iron Share	24.70%	106
Miles of Main - Plastic Share	40.80%	87
Average Length of Service (Feet)	71	52
System Density (Cust/Mile of Main)	98.9	5
Percent Unaccounted for Gas	1	41

As noted in the following table, almost 25% or 4,342 miles of cast iron exists in PSE&G’s gas distribution system. There is no other US utility with more cast iron/ductile iron in their system than PSE&G. This can readily be seen from the following table, where the top 11 utility systems with large amounts of cast iron and ductile iron are shown. PSE&G has over 38% more cast iron in its distribution system then the next closest utility.

Table 20-4 - PSE&G Top 11 U.S. Utilities with Cast-Iron Main

Public Service Electric and Gas Company 2007 Top 11 U.S. Utilities with Cast Iron Main					
Name	Total Miles of Main	Miles of Cast Iron Main	Miles of Ductile Iron Main	Total Miles of CI & DI Mains	% of CI & DI Systems of Total Miles of Main
PHILADEPHIA GAS WORKS	3,023	1,607	136	1,743	57.7%
PEOPLES GAS LIGHT & COKE CO	4,029	1,629	300	1,929	47.9%
KEYSPAN ENERGY DELIVERY - NY CITY	4,033	1,767	0	1,767	43.8%
BOSTON GAS CO	6,219.4	2,272	0	2,272	36.5%
CONSOLIDATED EDISON CO OF NEW YORK	4,264	1,386	0	1,386	32.5%
NIAGARA MOHAWK POWER CORP	3,102.3	900.1	17.2	917.3	29.6%
PUBLIC SERVICE ELECTRIC & GAS CO	17,618	4,438	0	4,438	25.2%
BALTIMORE GAS & ELECTRIC CO	6,832	1,363	0	1,363	20.0%
MICHIGAN CONSOLIDATED GAS CO (MICHCON)	18,520	2,728	0	2,728	14.7%
PECO ENERGY CO	6,658	829	60	889	13.4%
ALABAMA GAS CORPORATION	10,518.7	1,079.2	1.6	1,080.8	10.3%
Source: U.S. Office of Pipeline Safety 2007					

The amount of cast iron in PSE&G's system is also noteworthy in that a significant portion, 539 miles or 12.4% operates at a pressure above utilization pressure.[4] Cast-iron pipe, and in particular cast-iron pipe operating at above utilization pressure, is the type of pipe that many utilities are trying to reduce their exposure to by aggressively replacing or eliminating it from their system. In general, leaks or cracks in this type of pipe at elevated pressures can result in a significant gas escapes and incidents.

The following table provides the profile of PSE&G's mains at various design pressures by type of material:

[4] Utilization pressure is normally 6-10 inches of water column or approximately ¼ PSI.

Table 20-5 - PSE&G Miles of Distribution Main by Pressure System

Public Service Electric and Gas Company Miles of Distribution Main by Pressure System						
MATERIAL TYPE	UP*	15 PSI	60 PSI	120 PSI	Above 120 PSI	TOTAL
STEEL	579	1,769	3,597	127	14	6,086
PLASTIC	501	1,974	4,704	0.3	0	7,180
CAST IRON	3,803	476	63	0	0	4,342
COPPER	0	0.1	0.7	0	0	0.8
OTHER	0.3	2.4	0.8	0	0	3.5

Response to Discovery, OC-234
* Utilization Pressure

The consequence of the various material types, in particular bare steel versus coated steel, is discussed below ("Pipe Materials").

Performance Metrics. Gas Delivery operations drives strategy implementation through its organization by aligning key performance metrics with the utility level strategic plan. Monthly balanced scorecards are used to track results. The balanced scorecard groups 25 performance metrics in the following categories: People, Safety & Reliability, Economic, and Sustainability. Specific areas of performance measured vary from OSHA Recordable Injury Rate to regulatory compliance. For the most recent balanced scorecard report available, June 2009 Gas Delivery was achieving superior results on 18 of the 25 performance areas measured.[5]

Gas System Safety and Reliability. The principal objective of managing a gas distribution system is to provide safe, reliable service of gas at a competitive price. PSE&G has performed well in the area of safely delivering its commodity product. The following table shows the number of incidents PSE&G reported to PHMSA since 2005. In 2005, two incidents were reported both involving gas service lines. These incidents resulted in two injuries. Since 2005, PSE&G has not had to file a PHMSA incident report.

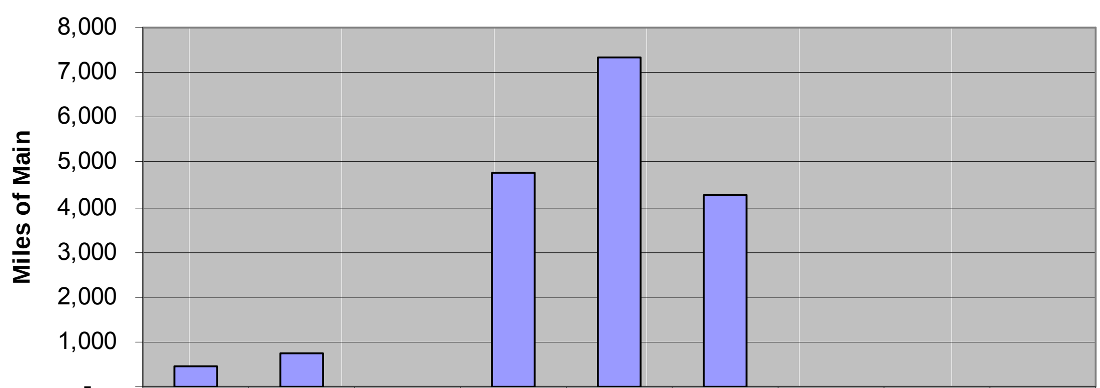
[5] Response to Discovery, OC-219.

Table 20-6 - PSE&G Explosions of Injuries 2005 - 2009

Public Service Electric and Gas Company Explosions or Injuries 2005 - 2009							
Year	Total Number of Injured	Was There An Explosion (Yes/No)	Incident Occured On	Component Which Failed	Material Involved	Year Component Installed	Area of Incident
2005	2	Yes	SERVICE LINE	JOINT	STEEL	1965	UNDER PAVEMENT
2005	0	Null	SERVICE LINE	BODY OF PIPE	POLYETHYLENE PLASTIC	1968	INSIDE/UNDER BUILDING
2006	0	No	N/A	N/A	N/A	N/A	N/A
2007	0	No	N/A	N/A	N/A	N/A	N/A
2008	0	No	N/A	N/A	N/A	N/A	N/A
2009	0	No	N/A	N/A	N/A	N/A	N/A
Source: PHMSA - Distribution Incident Data							

Pipe Materials. PSE&G's gas distribution system is comprised of approximately 58.4% metallic main. Metallic mains consist of 41.7% cast iron, 11.8% bare and unprotected steel, and 46.5% protected steel. The following table shows the gas distribution system mains inventory profile in miles of mains by material.

Table 20-7 - PSEG Gas Distribution System Mains Inventory Profile, 2009

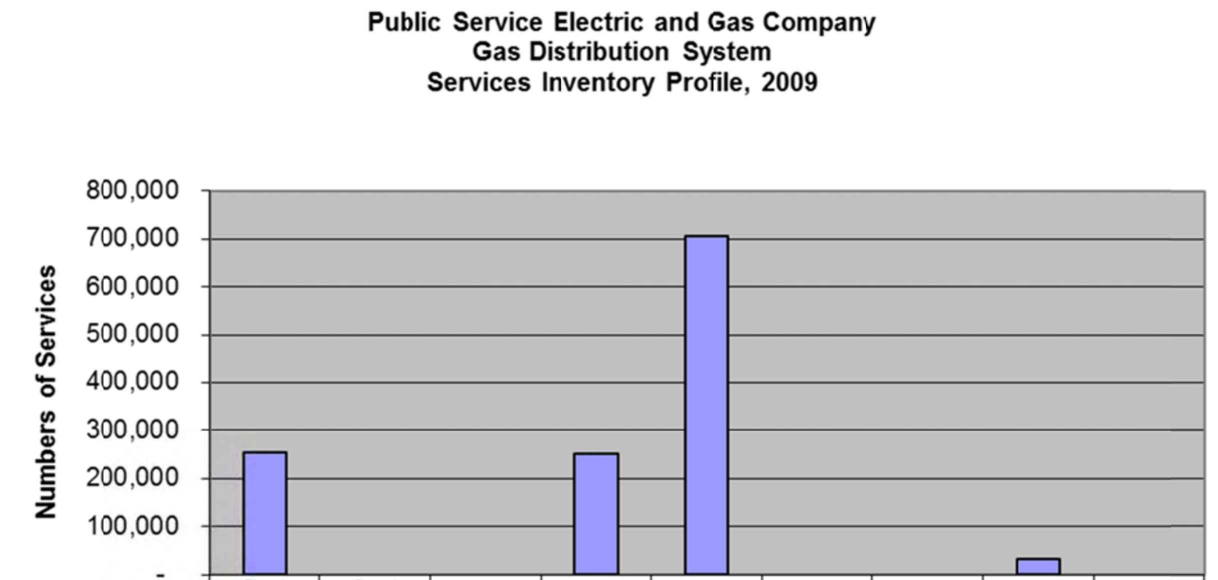


	Steel Unprotected /Bare	Steel Unprotected /Coated	Steel CP Bare	Steel CP Coated	Plastic	Cast Iron	Ductile Iron	Copper	Other
PSEG	447	762	-	4,774	7,317	4,284	-	1	3

Source: 2009 OPS Annual Report - Gas Distribution System

PSE&G's gas service lines are comprised of approximately 43.3% metallic service lines. Metallic services consist of 47% bare and unprotected steel, 6.1% copper and 46.9% protected steel. PSE&G has replaced all of its cast iron services. The following table shows the gas service line inventory profile in miles of service by material.

Table 20-8 - PSE&G Gas Distribution System Services Inventory Profile, 2009



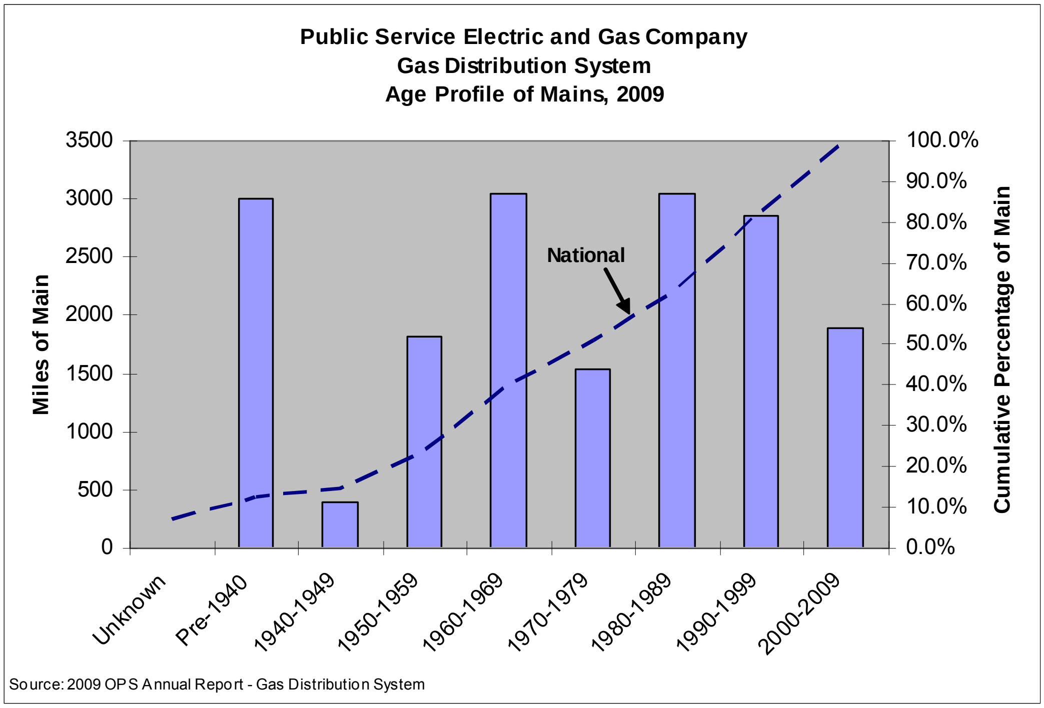
	Steel Unprotected/Bare	Steel Unprotected/Coated	Steel CP Bare	Steel CP Coated	Plastic	Cast Iron	Ductile Iron	Copper	Other
PSEG	253,728	-	-	252,634	707,546	-	-	32,940	-

Source: 2009 OPS Annual Report - Gas Distribution System

The types of materials in PSE&G's system are generally reflective of the types of materials available when they were installed or required by regulations.

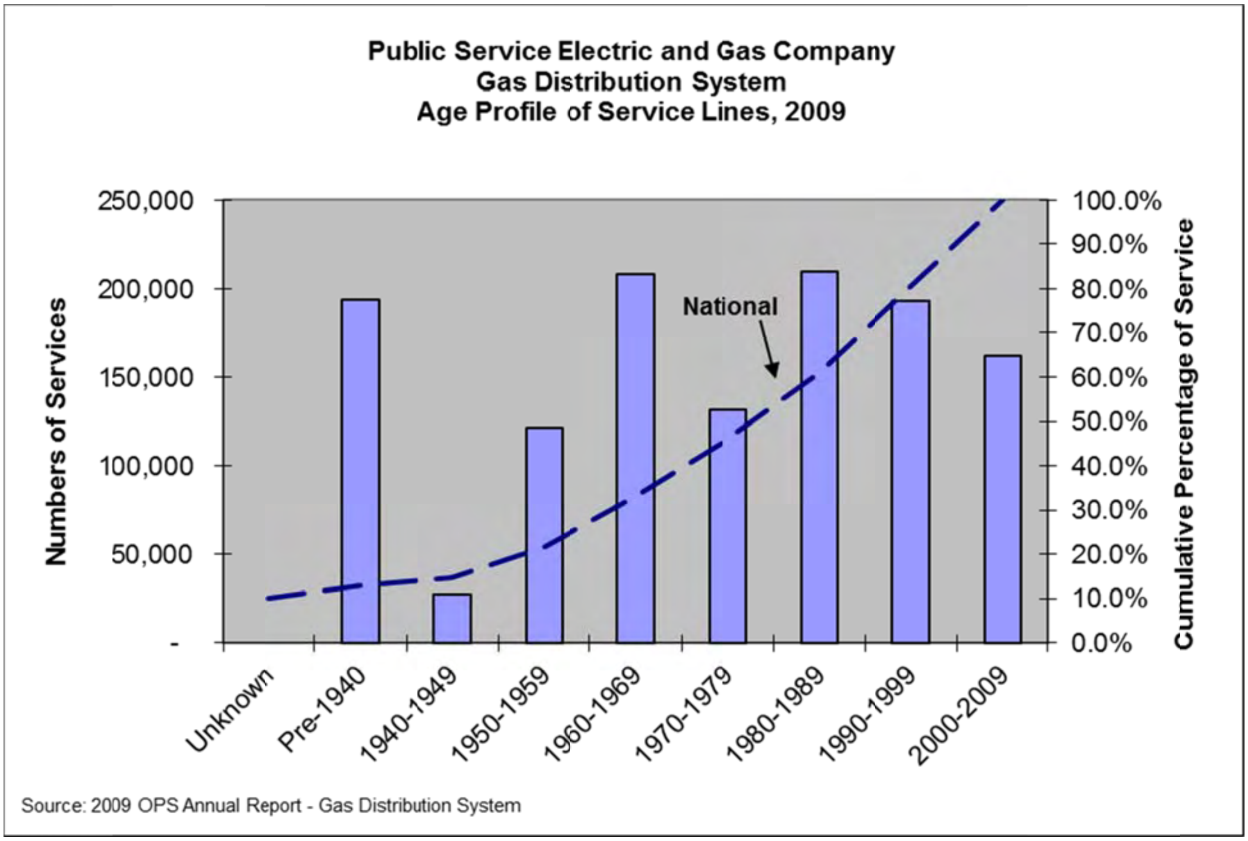
Aging Gas System. PSE&G's gas distribution system is older than most of the distribution systems in the U.S. The following table depicts the age distribution of PSE&G's main systems and clearly shows a mains distribution system that is older than the industry average. Approximately 17% of PSE&G's mains were installed prior to 1940. Over 29.7 % were installed prior to 1960. In 1970 the Federal Pipeline Safety Regulations were enacted. Title 49 CFR 192.455 requires gas operators to install externally coated and cathodically protected pipe after July 31, 1971, unless the operator can demonstrate that a corrosive environment does not exist. Steel pipelines installed prior to August 1, 1971 are required to be cathodically protected in areas in which active corrosion is found. Nationally, less than 40% of all mains, compared to about 47% of PSE&G's mains, were installed prior to the Federal Pipeline Safety Regulations being enacted.

Table 20-9 - PSE&G Gas Distribution System Age Profile of Mains, 2009



Similarly, PSE&G's gas service lines, when taken as a whole, are older than most of the gas service lines in other distribution systems. The following table shows 15.5 % of PSE&G's services were installed prior to 1940. Over 27.4 % were installed prior to 1960 and 44.1% were installed prior to 1970. Nationally, approximately 33.3% of the services were installed prior to 1970. Thus, similar to mains, we must conclude that PSE&G's services, when taken as a group, are also older than the typical service lines in the US.

Table 20-10 - PSE&G Gas Distribution System Age Profile of Service Lines, 2009



Mains and Service Replacement Policy. It is PSE&G'S policy to manage its distribution system in such a manner that those elements of the system which pose a potential risk are kept to a minimum.[6] Studies are conducted annually to monitor the leakage and breakage experience to ensure replacement and maintenance practices are sufficient to maintain a safe system. Annually, Gas Delivery's Asset Management group will conduct a complete review of the replacement program and evaluate replacement priorities.[7]

Five years ago the company made decisions to increase focus on bare steel main replacements. Bare steel comprised approximately 3.5% of the overall main system at the end of 2004. The company targeted replacement of all bare steel main within a 15 year horizon. The company continued to maintain a High Pressure Cast Iron and Utilization Pressure Cast Iron replacement program in addition to the bare steel main replacement program. The objective of the low pressure cast iron main replacement program is to maintain a leaks/mile and breaks/mile rate for this asset class below the upper performance limit reported to the BPU annually. The company also maintains compliance with

[6] Response to Discovery, OC-231.
[7] Response to Discovery, OC-231.

the required BPU 20% unprotected steel service replacement requirement in a defined area when records indicate 20% or more of the services in the area have exhibited leaks. The company currently averages approximately 6000 BPU services replacements per year.

Bare steel or cast-iron mains will not be replaced if they are in an area where outside construction activity occurs unless:

- There is a direct conflict.
- Cast-iron mains are within the zone of influence of new underground construction.
- The road box cutout reduces the cover over a cast-iron main to less than what is shown in the Gas Distribution Standards.
- The main has been identified as requiring future replacement in the 5 and 10 year System Reinforcement Plan or a Utilization Pressure Reinforcement Plan.
- The main is listed high on the priority main replacement lists.
- Bare steel services should only be replaced if they are leaking or meet the 20% rule described under bare steel services.

High-Pressure Cast Iron. According to PSE&G policy, all cast-iron mains 6” and lower in size and operating above utilization pressure should have already been replaced. If any new sections are discovered, they are replaced. An exception may be granted by the Planning & Design Manager – Engineering for short sections connected to 12” and larger mains.

A planned program is in progress to replace all 8” cast-iron mains operating above utilization pressure with the exception of short sections connected to larger mains. Also, a planned program is in progress to replace all 12” cast-iron mains operating in the 60 psi design systems with the exception of short sections connected to larger mains. All 10” and 12” cast-iron mains operating above utilization pressure which have experienced any breaks are included on a priority list for replacement.

Based on PSE&G policy, all cast iron services operating above utilization pressure should have already been replaced. If any new services are discovered, they are replaced.

Each year an evaluation is performed analyzing the feasibility of replacing shorter segments (less than 50 feet) of small diameter high-pressure cast iron remaining in the system. In the years 2007, 2008, and 2009 PSE&G retired 46 individual segments of high-pressure cast iron of 100 feet or less.

Table 20-11 - PSE&G Past 3 Years Progress Cast-Iron Main Replacement Program

Public Service Electric and Gas Company HP Cast Iron Replacement Past 3 Years Progress on Shorter Segments (less than 50 feet)				
Diameter	Pressure (psi)	# of Segments	% of Inventory	% of Footage
4	15	8	50%	65%
6	15	12	38%	61%
8	15	17	49%	53%
12	60	2	40%	58%
12	15	5	4%	4%
16	60	1	11%	6%
20	15	1	4%	3%
Source: OC-844				

These statistics reflect PSE&G's stated focus of efforts to replace 8" and smaller, 15 psi and 60 psi; and 12" 60 psi design cast iron.[8] However, the statistics also indicate slow progress in the removal of other classes of cast iron segments.

Utilization Pressure Cast Iron. Utilization pressure cast-iron mains, which have two or more breaks on the same segment, have replacement priority over all other leaking utilization pressure cast-iron mains. Mains with multiple joint leaks have the joints sealed but may be replaced if economically justified. Prioritized lists of main segments are issued by the Asset Management group each spring.

A replacement program is approved to replace all 3" cast iron unless they are found to be in a street under a paving moratorium. Those mains are replaced when the restriction expires.

All cast iron services should have been replaced. If a minor portion of a service is cast iron, it is replaced in conjunction with a replacement main or ahead of a construction project.

Steel and Bare Steel. As required by federal regulations, all mains identified under the Active Corrosion program are to be replaced within three years of being identified. Additional bare steel mains will be replaced annually based on a priority listing. A program, started five years ago, is targeted to replace all bare steel main within the next ten years.

Bare steel services are replaced when found to be leaking. All bare steel services found in a defined area are replaced when the records indicate 20% or more of the services in the area have exhibited leaks.[9] Additionally, bare steel services are replaced in conjunction with the replacement main program.

[8] Response to Discovery, OC-844.
[9] PSE&G Gas Distribution Standards, section titled "Unprotected Steel Services".

Plastic. According to PSE&G policy, any main or service made of nylon material is to be replaced when discovered. Any Reinforced Thermosetting Resin Pipe (RTRP or Red Thread) main less than 2" diameter will be replaced whenever found. Replacement of any other sizes will occur only when they are found to be leaking. A service of PE 3306 material will be replaced if found to be leaking. PE 3306 services should be replaced in conjunction with a replacement main project.

Overall Replacement Program Status. PSE&G's main and service replacement program, actual and estimated to be completed, is summarized in the following table. These figures represent replacements for all types of materials. Program work is considered somewhat discretionary, while "ahead of construction" is considered prudent work to be completed while roads are being resurfaced or direct construction otherwise conflicts. The sharp increase in program work projected in 2009 and 2010 is a direct result of advancing projects scheduled to be worked in future years and is due to the Economic Stimulus Program. Consequently, sharp reductions in program replacement are forecasted in 2011, 2012, and 2013.

Table 20-12 - PSE&G Actual and Projected Main and Service Replacement

Actual and Projected Main and Service Replacement						
	MAIN REPLACEMENT - FEET		SERVICE REPLACEMENT - COMPETE SERVICE			
YEAR	PROGRAM	AHEAD OF CONSTRUCTION	PROGRAM	AHEAD OF CONSTRUCTION	BPU MANDATED	LEAKS
2004	246,900	39,100	2,647	1,105	2,013	4,548
2005	318,600	52,900	3,021	1,202	442	4,125
2006	298,100	31,100	3,178	1,639	960	4,334
2007	287,400	25,100	3,007	1,171	2,226	4,175
2008	385,600	36,000	4,001	1,212	2,980	4,055
2009	497,000	25,100	5,350	700	5,050	3,900
2010	645,000	37,900	6,775	900	12,000	4,100
2011	90,000	31,000	980	875	3,000	3,500
2012	120,000	31,000	1,280	840	6,700	3,300
2013	130,000	31,000	1,380	800	6,300	3,200
Source: OC-232						

PSE&G prioritizes its Individual main segments selected for replacement based on studies as detailed in its Gas Distribution Standards.[10] Criteria used includes: number of previous leak or break repairs, year of repair, building density, operating pressure, number of underground utilities, and building setback. These factors are weighted and applied to each main segment having a history of leaks or breaks. The result of the analysis is a ranking of main segments by risk, which PSE&G refers to as relative hazard index. This index ranking along with pipe diameter causes further investigation and final development of the annual replacement main work plan. Gas Delivery reports it has not changed its replacement main selection process in the past five years.

[10] Response to Discovery, OC-276.

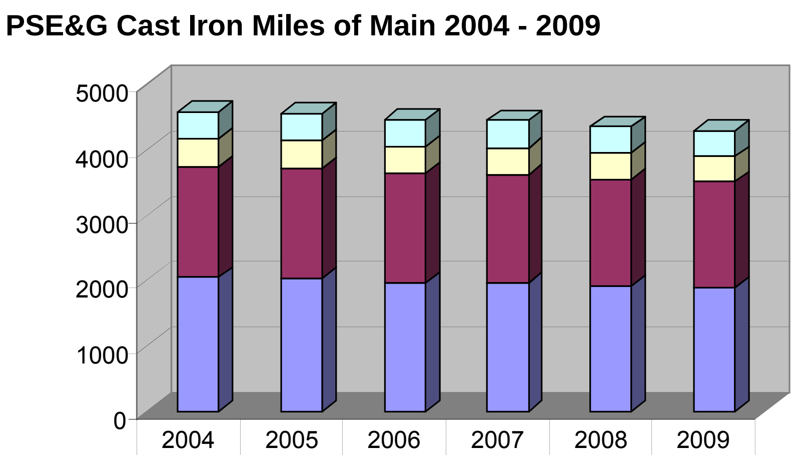
Services designated for program replacement are non-leaking unprotected steel, nylon or PE 3306 services. These services are replaced when they are part of a main replacement project or as a separate program, if they do not qualify for the mandated BPU replacement program.

As reflected in PSE&G's Gas Distribution Standards, the New Jersey Administrative Code Section N.J.A.C. 14:7-1.16, unprotected steel services must be replaced .[11] Consequently, a list of service leak locations due to corrosion or unknown causes is maintained to determine if 20% or more of the unprotected steel services in a definable area have exhibited leaks. A definable area is defined as addresses within a 100 number range of a municipal street. If the definable area calculation is 20% or more, then all remaining unprotected steel services will be replaced within the following two calendar years. Gas Delivery reports it has not changed its replacement service identification process in the past five years.

Cast-Iron Replacement Program Status. The following table shows the amount of cast iron PSE&G replaced by size from 2004 through 2009. The Company had 4,571 miles of cast-iron main in its system at the end of 2004. As of 2009, this amount has been reduced to 4,284. Thus the impact of the cast-iron replacement programs, previously described, amounts to replacing on average of 57.4 miles of cast-iron mains per year. At this rate, it would take approximately 75 years for PSE&G to replace the entire cast-iron main in its system. Some of the cast iron in PSE&G's system is already 120 years old. Conceivably, based on the present rate of replacement, PSE&G expects some of its cast iron to last as long as 195 years from its original date of installation.

[11] Response to Discovery, OC-276.

Table 20-13 - PSE&G Cast Iron Miles of Main 2004 – 2009



	2004	2005	2006	2007	2008	2009
Total	4571	4542	4453	4438	4342	4284
> 12 inches	403	402	415	415	402	398
> 8 inches and = 12 inches	431	426	407	405	390	382
> 4 inches and = 8 inches	1690	1680	1665	1661	1632	1612
> 2 inches and = 4 inches	2047	2034	1966	1957	1918	1892

Source: 2004 - 2009 OPS Annual Report - Gas Distribution System

Evidenced in the discussions above, the Company lacks defined goals for achieving total replacement of cast-iron mains. As recognized by PSE&G, the gas main and service replacement programs do not have a finite duration.[12] Furthermore, when asked when PSE&G anticipates removing all cast iron from its system, the Company responded it does not expect to replace all cast-iron main in the distribution system. Large diameter cast-iron main, 16” and larger, is only replaced if it is in conflict with or threatened by outside construction activities, or if general graphitization[13] has progressed to the degree as to make breakage likely.[14]

Although industry experience shows cast-iron main is an inherent safety issue in older systems, PSE&G has chosen to manage cast-iron replacement based on the previously described segment by segment risk assessment methodology. There are other approaches the Company should consider. One possible option could be a rate recovery mechanism authorized by regulators to accelerate the replacement of cast-iron pipe.[15]

[12] Response to Discovery, OC-268

[13] Cast iron contains carbon, in the form of graphite, in its molecular structure. One condition which can occur in the presence of acid rain and/or sea water is "graphitization." The stable graphite crystals remain in place, but the less stable iron becomes converted to insoluble iron oxide (rust). The result is that the cast iron piece retains its shape and appearance but becomes weaker mechanically because of the loss of iron. (Source: General Services Administration, 05010-04)

[14] Response to Discovery, OC-300.

[15] For example, the Illinois Commerce Commission in case 09-0166 ruled that it would be prudent for Peoples Gas Light and Coke Company to accelerate its 1,929 mile cast- and ductile-iron pipe replacement from a 50-year to a 19-year

System Inspections and Maintenance. PSE&G has well-structured and defined maintenance programs for its gas distribution facilities. In the following tables, the Gas T&D facilities are matched with the inspections and maintenance performed, frequency, data collected, and key performance indicators (KPIs) used to promote effective asset management. The tables include:

- Metering and Regulating Stations
- Pounds to Pounds Regulator Installations and District Regulators

From our knowledge of gas industry practices, the KPI's used are more detailed then is commonly found and represent a leading industry practice.

program. Increased benefits in system safety and reliability, environment, as well as future reductions in operation and maintenance costs all contributed to the Commission's approval. Likewise, in 2006, the BPU approved Elizabethtown Gas' $37 million pipeline replacement program. This was approximately a four-year program to replace about 60 miles of cast-iron gas mains, accelerating efforts over the previous 10 years that resulted in the replacement of approximately 144 miles of cast-iron pipe.

Table 20-14 - PSE&G Metering and Regulating Stations Inspection

Public Service Electric and Gas Company Metering and Regulating Stations Inspection				
Program	Inspection/Maintenance Areas	Freq.	Data Collected	Code Performance Meet/Exceed
PM	Gas Scrubber/Filter Separator	A	AMI Report P2	Meets
PM	Water Bath Heater	A	AMI Report P3	Meets
PM	Fuel Gas Supply	A	AMI Report P4	Meets
PM	Regulator	A	AMI Report P5	Meets
PM	Monitor	A	AMI Report P5	Meets
PM	Controller	A	AMI Report P6	Meets
PM	Controller Supply	A	AMI Report P7	Meets
PM	Relief Valve	A	AMI Report P8	Meets
PM	Glycol Fogger	A	AMI Report P9	Meets
PM	Catalytic Heater	A	AMI Report P10	Meets
PM	Electric Gas Heater	A	AMI Report P10	Meets
PM	Automatic Outlet Valve & Operator	A	AMI Report P10	Meets
PM	Filters	A	AMI Report P10	Meets
PM	Strainers	A	AMI Report P10	Meets
PM	Station Alarms	A	AMI Report P10	Meets
PM	Property	A	AMI Report P10	Meets
PM	Fire Extinguisher	A	AMI Report P11	Meets
PM	Valves	A	AMI Report P2-10	Meets
PM	Electronic Flow measurement	A	Calibration Report	Meets
PM	Station Instruments	A	Calibration Report	Meets
PM	Outlet Pressure Instruments	A	Calibration Report	Meets
PM	## Instruments	A	Calibration Report	Meets
PM	Control Points	A	Calibration Report	Meets
PM	Gas Chromatographs	M	Calibration Report	Exceeds
PM	Water Bath Heater	10 Yrs.	10-Year Heater Inspection Report	Exceeds
PM	Sulfur Measurement	M	Titrator Check List	Exceeds
PM	Atmospheric Corrosion Control Monitoring	A	Corrosion Inspection and Painting Report	Meets
PM	Automatic Line Break Automatic High-Pressure Closure Remote Activated ESD Controls	A	Automatic Line Break Operator Inspection & Testing Report	Meets
PM	Emergency Generators	M	Log Book Entry/Station Check List	Exceeds
INSP	Scrubber	M	Station Check List	Meets
INSP	Gas Heater	M	Station Check List	Meets
INSP	Pipeline M&R Facilities	M	Station Check List	Meets
INSP	PSE&G Regulator Facilities	M	Station Check List	Meets
INSP	RTU Facilities	M	Station Check List	Meets
INSP	MEG Fogger	M	Station Check List	Meets
INSP	Analyzers	M	Station Check List	Meets
INSP	Security & Safety	M	Station Check List	Meets
INSP	Valves, Drips, Buildings, Lighting, Relief Valves	M	Station Check List	Meets
Response to Discovery, OC-623.pdf (DR159)				

Table 20-15 - PSE&G KPIs

Public Service Electric and Gas Company KPI's							
	Yearly Results						
Measure	**Units**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**
PM/(PM+CM)	---	0.68	0.69	0.73	0.87	0.72	0.69
Regulatory Compliance	%	100%	100%	100%	100%	100%	100%
Jobsite time	%	61%	68%	69%	66%	72%	68%
Measurement Accuracy	%	0%	+0.1%	+0.3%	-0.05%	+0.14%	+0.39%
MH/CWO	Hours	---	---	11.72	7.17	9.12	12.48
MH/PWO	Hours	---	---	6.99	8.34	6.76	6.07
Fix It Right	%	94%	92%	91%	95%	98%	95%
Call Out Instances	---	103	125	103	90	88	97
Response to Discovery, OC-623.							

Table 20-16 - PSE&G Definitions

Public Service Electric and Gas Company Definitions	
	Description
PM (Program)	Preventive Maintenance
INSP (Program)	Inspection
A (Frequency)	Annual
M (Frequency)	Monthly
AMI	Annual Maintenance Inspection
PM/(PM+CM)	Rolling 12-month average ratio of the maintenance labor dollars for preventive maintenance to total maintenance.
Regulatory Compliance	The percentage of M&R station AMIs completed.
Jobsite Time	The percentage of time personnel is on the job.
Measurement Accuracy	The accuracy of PSE&G gas flow measurement received at GSOC as compared to the Pipeline billing flow.
MH/CWO	Labor hours per completed corrective work orders.
MH/PWO	Labor hours per completed preventive work orders.
Fix It Right	The percentage of corrective maintenance work orders for a specific equipment unit at a specific Station which did not require multiple visits within the last 30 days.
Call Out Instances	The total number of "after hour call" outs for problems at the M&R facilities in a single year.
Response to Discovery, OC-623.	

Table 20-17 - PSE&G Pounds to Pounds Regulators and District Regulators Inspection

Public Service Electric and Gas Company Pounds to Pounds Regulators and District Regulators Inspection				
				Code Performance
Program	Inspection/Maintenance Areas	Freq.	Data Collected	Meet/Exceed
Relief Study	Relief Capacity	A	Calculation/review of calculation of capacity to control to correct pressure	Meets
Capacity Study	Station delivery capacity compared to design day network models	A	% utilization compared to design day network models	Meets
Pressure Recording Chart Change and Review	Pressure Control	2 - 4 weeks	System Pressures	Meets
Inspection	Gas Present in Manhole	A	Yes/No	Meets
Inspection	Inlet Outlet Valves	A	Inspect/Operate	Meets
Inspection	Inlet Outlet Drips	A	Gallons	Meets
Inspection	Seal Pot Liquid Seal Depth	A	Inches	Meets
Inspection	Operate By-Pass	A	Yes/No	Meets
Inspection	Cleaned Needle Valve	A	Yes/No	Meets
Inspection	Aux. HP. Reg. Pilots	A	Inspect/Overhaul/Repair **	Meets
Inspection	Aux. UP Reg. Pilot	A	Inspect/Overhaul/Repair **	Meets
Inspection	Aux. Piping Clear	A	Yes/No	Meets
Inspection	Aux. Bowl Diaphragm	A	Inspect/Overhaul/Repair **	Meets
Inspection	Inspect Seats	A*	Inspect/Replace	Meets
Inspection	Main Bowl Diaphragm	A	Inspect/Overhaul/Repair **	Meets
Inspection	Baffle Diaphragm	A	Inspect/Overhaul/Repair **	Meets
Inspection	Test Pit Vent	A	Yes/No Remarks	Meets
Inspection	Test Reg. Vent	A	Yes/No Remarks	Meets
Inspection	Check Operation and Lockup	A	Yes/No	Meets
Inspection	Waterproof Equipment	A	Yes/No	Meets
Inspection	Cleaned Manhole	A	Yes/No	Meets
Inspection	Check Accuracy Recording Gauges	A	Yes/No	Meets
Inspection	Repaired Recording Gauge	A	Yes/No Remarks	Meets
Inspection	Pressure Setting	A	Outlet Pressure	Meets
		* 5 yrs for Lb/In regs.	** Lbs/Lbs regulators overhauled every 10 years. Lbs/Inch regulators overhauled only as needed.	
Response to Discovery, OC-623.				

The following "superior" maintenance/inspection activities or practices have been identified by PSE&G as being employed in their gas distribution system to help ensure reliability and safety.[16]

1. The Remote Methane Leak Detector, which utilizes laser-based optical scanning technology, was successfully evaluated and implemented statewide. This new technology is accurate up to a distance of 100 feet and was used to replace conventional flame ionization leak detection equipment for the service and manhole, or business, surveys.
2. In order to assist in the inspection of live gas mains operating up to 60 psig without disruption of service to customers, PSE&G supported development of closed circuit television equipment. Using tethered robotic systems, this equipment can be used for internal inspections of gas facilities, searching for water intrusion, and verifying tap or service locations.
3. In order to install excess flow valves (EFVs) on existing PE services with outside meter sets without making an excavation, PSE&G supported development of using conventional EFVs with a special retention system and no-blow technology. Installing an EFV without having to make an excavation represents a more efficient process.

In addition, there are a number of activities in which the Company exceeds regulatory requirements. These include:[17]

- Leakage control surveys conducted in business areas and other specified locations during severe winter weather.
- Public building inspections completed every three years versus the required five. In addition, this inspection includes: curb valve accessibility, testing curb box for gas, and placement of curb valve shutoff key to assure fit.
- House heater periodic inspections.
- Transmission pipelines surveyed two times a year versus the required one time.
- Material and construction quality control.
- Gas odorant control testing performed monthly.
- Gas analysis performed monthly to ensure gas quality from various supply sources.

Gas Delivery Information Technology Systems. The following is a synopsis of the information technology systems utilized to manage the various data and records maintained for gas distribution.[18]

[16] Response to Discovery, OC-278.
[17] Response to Discovery, OC-621.
[18] Response to Discovery, OC-495.

- Computer Aided Dispatch - used to dispatch work to mobile data terminals assigned to construction and operations employees. System transmits timesheet data, as-built data, trouble reporting, and job status. The computer-aided dispatch system links with Outage Management, One Call, SAP, and CMMS systems.
- Graphical Information System - used as the asset register for transmission and distribution facilities. Graphical information systems are a combination of computer software, hardware, and data that links geographical data to descriptive information.
- Investment Evaluation System - used to perform relative cost to value analysis for all proposed utility investments. In addition, the system provides a framework for identifying benefits of performing and the risk of not performing, as well as the relevant underlying assumptions for proposed investments.
- SAP - used for financials, human resources, materials management, time data, and customer data, billing, and work management. This system is used to capture both planned and actual labor, materials, and financials.
- SAP Mobile App - used for scheduling, execution, and completion of customer system generated appliance service business work.
- Stoner Gas Net - used to perform analysis of the gas system load at various distribution system pressures.
- Gas Management and Control Systems - used to control metering regulating stations and acquire gas delivery flow and volume information. This system is linked with the gas management system for monthly reporting.

A number of new reports were implemented in 2009 including:

- SAP/CAD Data Warehouse Layout Reports.
- New Meter Orders.
- Number of CAD Jobs Not Worked in Last six months:
    - Open Operations
    - Closed Operations-Last Worked
    - Open Notifications
    - Inactive more than six months should be closed
- Notifications Answered-24GT Turn Around Time.
- Cycle time for Completed-Date Filter Range on Task Completion Date.

- Material Reservations - Includes all columns from open notification report plus material reservation data.

Training Program Summary. Successful operations and maintenance programs require a skilled and well-trained workforce in all areas such as knowledge of PSE&G's systems and procedures, safety, and Operator Qualification. PSE&G's Technical Training Department is part of the Utility Operations Support Department and provides technical training to many of the 2,000 employees of Gas Delivery. The core curriculum for technical training is primarily contractually negotiated apprentice programs for craft employees, across various union position descriptions.[19] In addition to technical training, there is extensive safety related training, which varies from respiratory protection certification to DOT hazardous materials training. Also, leadership development academies are held for first-line supervisors and middle managers.

Training is delivered through various means including: traditional instructor/student classroom and computer based training. Trainers will include: a staff of subject matter experts, fulltime instructors; operational line of business experts, acting as instructor adjuncts; contract adjuncts and out-sourced training.

Instruction is organized by teams of instructors and the Gas Delivery Team provides instruction in the installation, maintenance, and repair of the Gas Delivery System as well as Operator Qualification. 49 CFR Part 192, Subpart N outlines requirements for natural gas pipeline operators to perform ongoing evaluation and qualification of all persons performing certain operating and maintenance tasks. Each pipeline operator is required to have and follow a written qualification plan, to ensure that all appropriate employees, or employees of approved contractors, are qualified in accordance with the plan, and maintain adequate records to document the qualifications. The PSE&G Operator Qualification (OQ) Written Plan establishes the identified operations and maintenance tasks, or OQ Covered Tasks, the qualification methods to be used for employees and contractors, the frequency of the qualifications, and the record keeping requirements.

The gas delivery training process is fully defined and contains sections dealing with: purpose, ownership, process flow diagram, a breakdown of process steps, explanation of terms and definitions used, cross-references, and development history. Within the process steps are the following sub steps: requests for training, does the solution exist, analysis, analysis feedback, design, development, scheduling, classroom training, student records, evaluation and feedback, significant improvement needed, and continuous curriculum improvement. Where appropriate, metrics for these subsections have been created to measure performance.

[19] Response to Discovery, OC-145.

B. System Reliability

PSE&G's Gas Delivery Business uses the ratio of gas leak reports per mile of main and service and cast-iron breaks per mile to define the reliability of the distribution system.[20] These metrics are tracked on the Company's scorecard as part of PSE&G's Strategic Plan and as a result, have very high visibility and focus across the Company.[21] PSE&G drives strategy implementation through the business by aligning key performance metrics with its strategic plan and uses monthly scorecards to report progress. PSE&G was inducted into the Palladium Group Balanced Scorecard Hall of Fame for Executing Strategy in 2007.[22]

Detecting and fixing leaks in a gas distribution system serves to minimize risk to the public and as such it provides a good representation of distribution system reliability and changing asset condition. The leak per mile and cast-iron breaks per mile metrics are also used by numerous gas utilities in peer panel studies allowing for performance comparisons across the industry.

Leak Management. Gas distribution companies have in place programs consisting of processes, polices, procedures, standards and practices that address the issue of system safety and reliability, sometimes referred to as "system integrity." The key to system integrity is the sustained prudent risk management of gas distribution mains and services – specifically for PSE&G there is a necessary focus on the cast iron and steel systems. Cast iron and steel mains and services require close and continued prudent management focused on maintenance and replacement. Of particular concern are cast-iron main systems located in urban areas in close proximity to populations. Leaks or breaks on these systems can be particularly hazardous because of the potential volume of escaping gas involved, especially if the main is large in diameter and/or operating at a higher pressure.

In order to put PSE&G's main and service leakage into perspective, we present two different charts. The first chart, Table 18, shows the repaired and eliminated main and service leaks in 2009 for a comparable set of companies that have distribution systems somewhat similar to PSE&Gs. This chart consists of the 11 USA utilities with the greatest amount of cast iron in their system. The second chart, Table 19, shows the total main and service leaks repaired and eliminated to the panel of companies which PSE&G benchmarks itself to.

Table 18 puts PSE&G's distribution system in a fair comparison because variation of distribution system materials is an important distinction when assessing reliability performance. Newer distribution systems, with a higher percentage of cathodically protected steel pipe and plastic pipe, typically will experience lower leakage rates. For the year 2009, PSE&G's main distribution system experienced .21

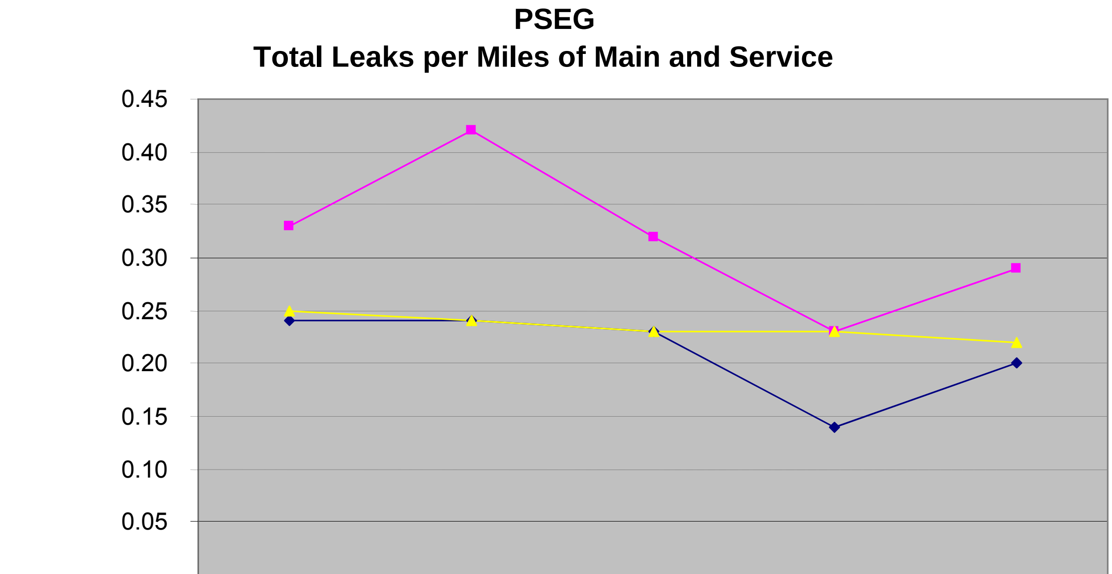
[20] Response to Discover OC-271
[21] Response to Discovery, OC-218.
[22] The Palladium Group is a consulting firm founded by Drs. Norton and Kaplan from the Harvard Business School. Drs. Norton and Kaplan developed the methodology of measuring the effectiveness of the balanced scorecard to execute business strategy.

gas leaks per mile and for services .31 leaks per 100 services. The leakage rates for the comparable companies were .64 per mile for mains and .58 per 100 services. Thus PSE&G's leakage rates compare favorably to the companies with relatively similar systems, but are nearly twice the national average for main leaks of .12 gas leaks per mile. The national average represents all utilities with gas distribution systems, and includes many companies with greater amounts of the newer cathodically protected steel and plastic pipe in their systems. The leakage rate dramatically changes however for services, where PSE&G's .31 service leaks per 100 services are exactly half of the national average for all utilities.

Table 20-13 - PSE&G Gas Distribution System Repaired and Eliminated Services and Main Leaks in 2009

Public Service Electric and Gas Company Gas Distribution System Repaired and Eliminated Services and Main Leaks in 2009						
Name	Total Main Leaks	Total Service Leaks	Total Miles of Main	Total # of Services	Main Leaks per Mile of Main	Service Leaks per 100 Service
PUBLIC SERVICE ELECTRIC & GAS CO	3,663	3,868	17,588	1,246,848	0.21	0.31
MICHIGAN CONSOLIDATED GAS CO (MICHCON)	2,868	5,257	18,599	1,176,513	0.15	0.45
BOSTON GAS CO	7,644	2,797	6,264	483,050	1.22	0.58
KEYSPAN ENERGY DELIVERY - NY CITY	2,101	699	4,069	561,426	0.52	0.12
PHILADELPHIA GAS WORKS	2,655	4,133	3,029	463,385	0.88	0.89
PEOPLES GAS LIGHT & COKE CO	1,649	1,295	4,086	507,506	0.40	0.26
BALTIMORE GAS & ELECTRIC CO	2,210	3,289	6,905	516,628	0.32	0.64
CONSOLIDATED EDISON CO OF NEW YORK	5,734	3,366	4,283	385,223	1.34	0.87
ALABAMA GAS CORPORATION	3,222	6,180	10,887	540,667	0.30	1.14
NIAGARA MOHAWK POWER CORP	2,656	1,019	3,129	187,785	0.85	0.54
PECO ENERGY CO	3,083	1,479	6,703	426,763	0.46	0.35
NATIONAL AVERAGE	**104**	**291**	**878**	**47,243**	**0.12**	**0.62**
Source: 2009 OPS Annual Report - Gas Distribution System						

Table 20-19 - PSE&G Total Leaks per Miles of Main and Service



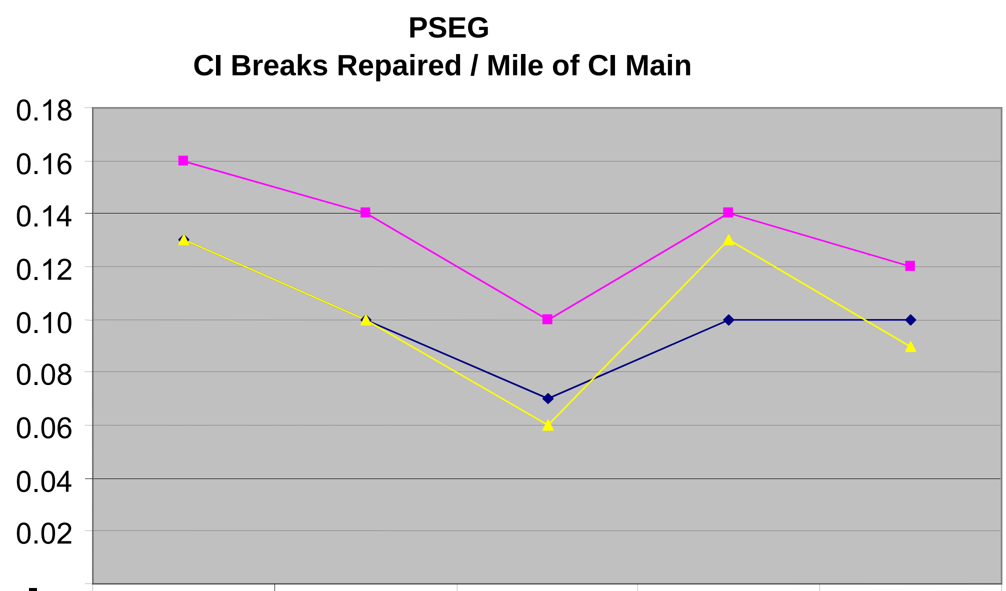
	2004	2005	2006	2007	2008
1st Quartile	0.24	0.24	0.23	0.14	0.20
Median	0.33	0.42	0.32	0.23	0.29
PSE&G	0.25	0.24	0.23	0.23	0.22

Source: PSE&G's data - 2008 Gas Data Blinded.pdf - Page 5

PSE&G gas distribution system also compares favorably when main and service leak performance is monitored and tracked against the 30 companies participating in the peer panel. In fact, the Company performs better than the median of the total leaks per mile of main and service for the peer panel. This includes comparison with companies whose systems are somewhat like PSE&G's, as well as newer systems that contain mostly cathodically protected steel and plastic and little to no cast iron and bare steel. The above tables clearly show that Company's distribution system is maintained near first quartile performance. For the year 2007, overall performance for the peer panel dramatically improved causing PSE&G to only match the peer group median performance. Overall for PSE&G, the total trend between 2004 and 2008 is sloping slightly downwards, meaning slightly less leaks are being encountered each year.

Cast-Iron Main Breaks. While there is no annual target for cast iron breaks per mile due to the unpredictable influence of winter weather, cast iron is being replaced at a rate Gas Delivery forecasts will manage the annual break/mile rate to stay close to first quartile performance when compared to the benchmark panel. As shown in the following table, the Company has been able to meet or exceed first quartile performance in every year except 2007. In 2007 cast iron breaks per mile of cast-iron main remaining in the system reached .13 as compared to .10 for the first quartile and .14 for the median of the group peer panel.

Table 20-20 - PSE&G CI Breaks Repaired / Mile of CI Main



	2004	2005	2006	2007	2008
1st Quartile	0.13	0.10	0.07	0.10	0.10
Median	0.16	0.14	0.10	0.14	0.12
PSE&G	0.13	0.10	0.06	0.13	0.09

Source: PSE&G's data - 2008 Gas Data Blinded.pdf - Page 5

While these results are good, we are concerned that the makeup of the peer panel only has one company besides PSE&G with an extensive amount of cast iron in their distribution system. In fact, totaling the cast iron of the other 29 participating peer panel utilities yields a distribution system that just somewhat exceeds the cast iron PSE&G maintains. Consequently, although this comparison is positive for Gas Delivery's distribution system, it also provides limited assurance regarding first quartile performance.

Leak Surveys. Leak notifications originate from either the Company's leak surveys and inspections or sources outside the Company, generally referred to as public reports. Leak surveys are conducted in accordance with Federal Regulations, specifically 49 CFR part 192. PSE&G's leak survey operational procedures are reflected in its Gas Distribution Standards.[23]

[23] Response to Discovery, OC-276.

The type of survey conducted and miles of main surveyed for 2009 is shown in the table below.

Table 20-21 - PSE&G Gas Delivery Leak Surveys

Public Service Electric and Gas Company Gas Delivery Leak Surveys	
Type of Survey Conducted	**2009 Miles of Main Surveyed**
Leak Mobile and PRW (Private Right of Way) Leak Survey	17,600
Manhole / Business Area Leak Survey	881
Service Leak Survey	6,136
Transmission & HP Dist. Leak Survey	72.3
Response to Discovery, OC-845	

The gas leak classification process utilizes a three-level grading system to evaluate the severity of a leak, with provision of actions to be taken criteria based on the leaks severity.[24] The definitions for leak grades are as follows:

- Grade 1 - concentration of gas which presents an immediate hazard. This type of leak needs to be made safe immediately and repaired as soon as possible.
- Grade 2 - non-hazardous at time of detection, but needs to be scheduled for repair based on potential future hazard. This type of leak needs to be repaired or rechecked within six months.
- Grade 3 - non-hazardous at time of detection and is expected to remain so. This type of leak needs to be repaired or rechecked within 15 months.

The following table provides PSE&G's leak history by classification for the period of 2004 to 2009. Trending leaks by respective "Leak Class" and the "Total" categories generally reveals they are all trending downward. The only exception to this is for Grade 2 leaks, where the number of leaks reported has actually grown over time.

[24] Gas Distribution Standards Part 4, Chapter 4, Sect. 1.7 Leak Classifications and Action Criteria, appended.

Table 20-22 - Leak Reports by Year

Public Service Electric and Gas Company Leak Reports by Year Leak Class: 2004-2009				
	Leak Class			
Year	**1**	**2**	**3**	**Total**
2004	4,121	2,480	1,447	8,048
2005	3,665	2,651	1,496	7,812
2006	3,476	2,743	1,547	7,766
2007	3,692	2,600	1,467	7,759
2008	3,356	3,144	1,095	7,595
2009	2,923	2,763	1,213	6,899
Response to Discovery, OC-240, OC-846				

The following table describes the leak backlog by classification by year for the last six years. The backlog of leaks in all three leak classes rose in 2008, but has since resumed the downward trend observed in the earlier reported years.

Table 20-23 - Backlog of Open Leaks by Leak Class 2004 – 2009

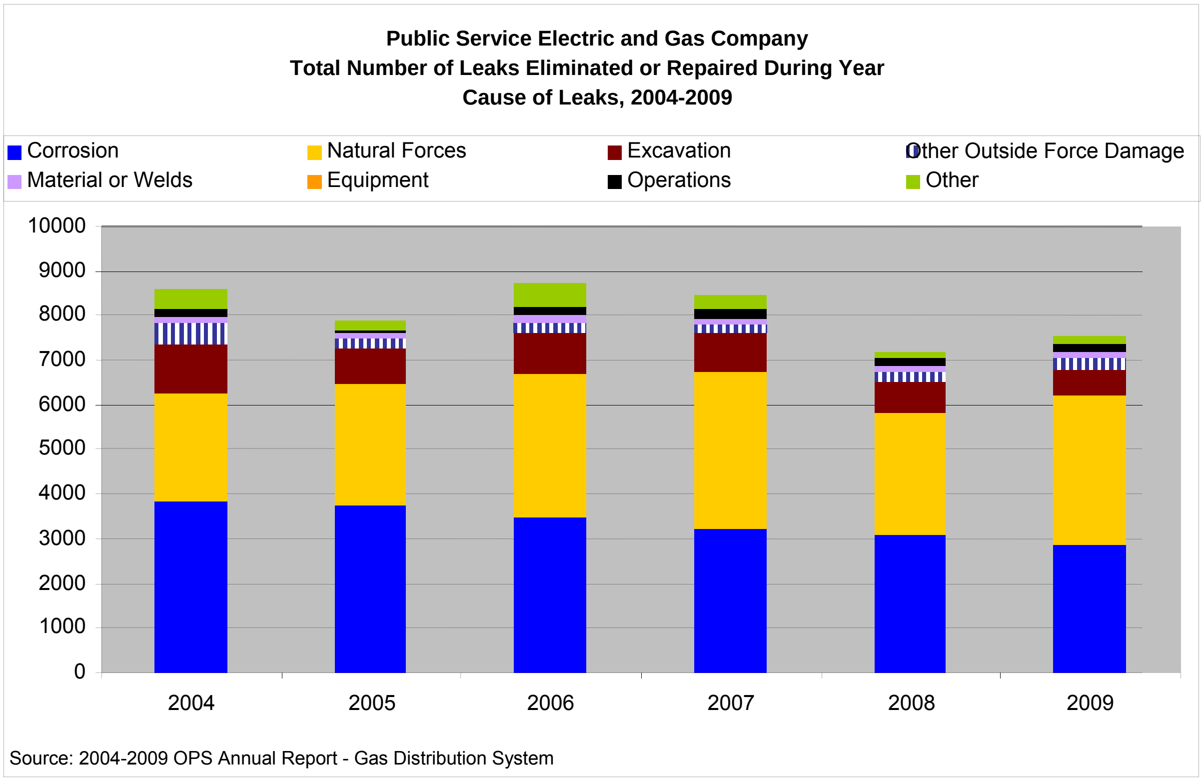
Public Service Electric and Gas Company Backlog of Open Leaks by Leak Class: 2004-2009				
	Leak Class			
Year	**1**	**2**	**3**	**Total**
2004	*	*	*	3,200
2005	*	*	*	2,955
2006	19	897	994	1,910
2007	30	796	805	1,631
2008	40	812	952	1,804
2009	23	734	801	1,558
* Leak Class distribution is unavailable				
Response to Discovery, OC-240, OC-286				

The following table is a bar chart which describes the causes of leaks between the years 2004 and 2009. Corrosion and Natural Forces are by far the most common cause followed by Excavation. The definitions for these causes of leaks are as follows:

- Corrosion refers to the deterioration of mental pipe occurring on the outside wall of the pipe which results from a reaction with its environment.
- Natural Forces includes a variety of earth movement external stresses such as: subsidence, landslide, frost heave, ground settlement, mudslides, and disturbance due to heavy rain.

- Excavation is damage inflicted by first, second, or third parties resulting in a loss of pipeline integrity.

Table 20-24 - Total Number of Leaks Eliminated or Repaired During Year



Our conclusion in assessing system reliability is that Gas Delivery has performed well over the period reviewed. PSE&G's inspection, maintenance, and replacement programs have been consistent with its replacement philosophy to manage the system to avoid increasing failure rates of bare steel and cast iron.

Pipeline Integrity Management. The Pipeline Integrity Management Program (PIMP) establishes, coordinates, and implements processes, policies, and practices to help ensure the safety, integrity, and efficiency of the DOT gas transmission pipeline system. The policies set forth in the PSE&G's PIMP are intended to guide the development, implementation, and continual improvement of the various elements covered by the PIMP.

PSE&G's transmission system originates downstream of the city gate station and delivers gas to the distribution system. Along the way, particularly in the Hudson/Essex County areas, there are numerous power plants that are also fed off the transmission system. PIMP tracks the 61 miles of transmission and 10 miles of high-pressure distribution pipe. High Consequence Areas (HCA's) are being re-evaluated as specific building types and building density change. PSE&G outsources most of the inspection assessment work. Lines capable of being "pigged" or surveyed internally are conducted by GE with inline inspection devices; for non-piggable pipes, CORPOR is used for external corrosion direct assessments (ECDAs). Since the inception of the pipeline integrity management program, Gas Delivery has found eight anomalies. Two were discovered by internal inline assessments and six by ECDA. The kinds of anomalies found included dents, coating despondent, and corrosion pitting.[25]

PSE&G is required to submit periodic reports to the Office of Pipeline Safety concerning the status of its gas integrity management program. We have reviewed the reports submitted and have found them consistent with PSE&G's PIMP procedures.[26]

Since Pipeline Integrity Management Program inception, Gas Delivery has identified the following key improvements.[27]

- All transmission lines were analyzed in a risk assessment in 2004, and placed on a seven-year cycle of physical assessments based on priority risk rankings, beginning in 2005.
- Now more than halfway through the inspection cycle, PSE&G has performed various improvements including coating repairs, valve upgrades, and cathodic protection improvements.
- Geographic documentation has been developed of the transmission pipeline physical characteristics and of the findings as to their condition resulting from the assessments.

Distribution Integrity Management. The Pipeline and Hazardous Materials Safety Administration (PHMSA) published the final rule establishing integrity management requirements for gas distribution pipeline systems on December 4, 2009, (74 FR 63906). Gas distribution system operators are given until August 2, 2011 to write and implement their program. The regulation requires operators to develop, write, and implement a distribution integrity management program with the following elements:

- Knowledge
- Identify Threats
- Evaluate and Rank Risks
- Identify and Implement Measures to Address Risks
- Measure Performance, Monitor Results, and Evaluate Effectiveness

[25] Response to Discovery, OC-237.
[26] Response to Discovery, OC-237.
[27] Response to Discovery, OC-238.

- Periodically Evaluate and Improve Program
- Report Results[28]

The vast majority of PSE&G's gas system will be subject to the new distribution integrity requirements. Gas Delivery will need to write and then implement its Distribution Integrity Management Program (DIMP). By focusing on the previously stated elements, PSE&G will have an increased opportunity to evaluate its distribution integrity performance and continue to improve its program.

C. Gas System Capital and O&M Costs

PSE&G has an annual, multi-step and multi-level corporate budgeting process, where the budgets undergo several levels of review before they are finalized. Close attention is given to the possible impact on reliability due to budget changes. Corporate and division management monitor budgets and reliability from a corporate scorecard perspective and will make adjustments as necessary to meet the KPIs.

A complete description of the capital (CAPEX) and operations and maintenance (OPEX) budgeting process appears in Section D of the chapter entitled "Electric Delivery and Operations Management."

For Gas Delivery, there have been no reductions to CAPEX budgets in the past five years. The OPEX budget has been reduced from the original budget in 2008 as indicated in the table below. All of the other years described in the following table reflect no budget reductions.

[Begin Confidential]

Table 20-25 - Gas Delivery OPEX Budget

Public Service Electric and Gas Company Gas Delivery - Capital O&M Budget					
(in millions)	**2005**	**2006**	**2007**	**2008**	**2009***
[redacted]					

[End Confidential]

[28] Department of Transportation website http://primis.phmsa.dot.gov/dimp/.
[29] Response to Discovery, OC-264.

Capital Investment. The following two tables identify all ongoing capital investment programs related to gas systems safety, capacity, and reliability such as service line replacement and cast-iron main replacement. For each program the planned budgeted/authorized and actual expenditures for the past five years and future five years are listed. The estimated future expenditures 2010 and 2011 were not provided by PSE&G because "the proposed plan had yet to be approved".[30] Between 2004 and 2008 the Company averaged approximately 306,000 feet of main replacement and 4,800 service replacements per year.

[Begin Confidential]

Table 20-26 – Planned Gas Main and Service Replacement

Public Service Electric and Gas Company Planned Gas Main and Service Replacement								
	2004		2005		2006		2007	
	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual
[redacted]								

Table 20-27 - Gas Main and Service Replacement Future Plans

Public Service Electric and Gas Company Gas Main and Service Replacement Future Plans							
		2008		2009		2012	2013
		Plan	Actual	Plan	Forecast	Estimated	Estimated
[redacted]							

[30] Response to Discovery, OC-268.

Table 20-28 – Actual Costs – Main & Service Replacement Program

Public Service Electric and Gas Company Actual Costs - Main & Service Replacement Program
[redacted]

[End Confidential]

The noticeable increases in 2009 and 2010 were due to funding by the New Jersey Economic Stimulus Program. Likewise, the return to lower levels of planned expenditures in future years reflects the lack of replacement work needed as a result of advancing projects through the Stimulus Program.

The cost of replacement main and service work varies due a variety of circumstances including location, type of material, size, depth of cover, ground cover, etc. Consequently, it is not possible to draw any conclusions with regard to the reasonableness of the replacement program from a cost per foot perspective. However, we can compare Gas Delivery cost per foot of replacement main and service installation to the 30-company panel, which PSE&G normally compares itself to. The following table shows that the cost to replace mains in PSE&G territory is consistently well above the median for the peer panel. This comparative ranking is consistent with what one would expect given the urban/suburban geographic area Gas Delivery serves.

[Begin Confidential]

Table 20-20 – Main Replacement Cost per Foot Installed

[redacted]

Table 20-30 – Service Replacement Cost per Foot Installed

[redacted]

[End Confidential]

This comparative ranking is consistent with what one would expect given the urban/suburban geographic area Gas Delivery serves. Since the chart measures cost per foot of renewed service (and the time to renew a service is somewhat independent of the length), utilities with shorter services in the peer panel will generally experience a higher cost per foot.

To safely manage gas distribution systems with large inventories of cast iron and aging bare/unprotected steel mains, gas distribution companies implement formal main replacement programs. This replacement activity is reflected in gas system capital expenditures. The following table shows, for a panel of companies PSE&G routinely compares itself to, that PSE&G generally spends more on capital for mains and services than the median amount spent by the other 30 companies in the peer panel.[31] The only year in which it was slightly below the peer panel median was 2007. Other than in 2007, PSE&G consistently tracks higher capital spending when compared on an existing main and service basis.

[31] Chart is the sum of total direct costs for new main, new service, replace main, replace service/existing miles of mains and service.

[Begin Confidential]

Table 20-3 . – Cost Construction per Existing Mains and Services

[redacted]

Table 20-32 – Cost Construction per Number of Customers

[redacted]

Table 20-33 – Cost O&M per Miles of Main and Service

[redacted]

[End Confidential]

Pipeline Integrity Program Costs. As discussed in the previous section, PSE&G's Pipeline Integrity Management Program (PIMP) tracks 61 miles of transmission and 10 miles of high-pressure distribution pipe. For a company with over 17,000 miles of distribution piping in its system, the portion that is maintained as transmission is very small.

The PIMP capital and O&M expenditures include: developing the initial pipeline integrity management program; gas transmission system modifications; baseline assessment; remediation; prevention and mitigation; program auditing; and other related costs.

[Begin Confidential]

Table 20-34 – Capital and O&M Expenditures

Public Service Electric and Gas Company Capital and O&M Expenditures						
	*2004	2005	2006	2007	2008	Oct 2009 YTD
[redacted]						

[End Confidential]

D. System Planning and Design

Gas distribution system send-out fluctuates by hour, day, and season. The pattern of these demands defines the gas supply and distribution systems planning parameters. The maximum design load determines the capacity required for the pipeline system. Consequently, good estimates of the present and future demands that translate into system requirements must be analyzed in order to ensure economic design of the required gas distribution facilities.

System planning involves analysis of load projects and forecasts, capital investment planning based on specified criteria, and economic analysis to ensure capacity will be provided to reliably supply the gas demand of present and future customers.

PSE&G performs system design analysis with a focus on reliability, and in adherence with federal and state codes; and where the codes do not agree, the more restrictive regulation applies.[32] In addition, PSE&G propagates its system designs by providing engineering manuals with updates and training to field personnel when new equipment or procedures are introduced. This is periodically done jointly with equipment manufacturers. Quality assurance/quality control is performed by frequent field interaction via monthly meetings where division and field personnel provide feedback on any standard/procedure with requests for modifications or creation of a new standard.

[32] Response to Discovery, OC-279.

The following details a structured approach to system planning, which involves design, planning, and capital construction budgeting.

System Design. The capacity of a gas distribution system can be defined as the maximum sustainable load operating within system design limits. Design limits vary depending upon the Maximum Allowable Operating Pressure (MAOP) and the system minimum allowable operating pressure. System minimal allowable operating pressures are defined in Gas Delivery's Gas Design Standards. The MAOP's PSE&G operates its distribution systems at are utilization pressure (approximately 6 – 10" water column or ¼ psi), 15 psi, 60 psi, and 120 psi design. Network analysis software is used to study anticipated system performance under various assumed conditions. PSE&G uses Stoner Synergy Modeling software to conduct its network analysis. This software is generally considered a standard in the gas industry. The network analysis studies can predict if areas of the system would perform below minimum allowable pressure under design day conditions. When this situation is encountered various assumptions can be modeled that will identify specific reinforcements needed to add required capacity.

PSE&G was requested to identify natural gas system design and engineering practices which exceed the minimum regulatory requirement.

Examples include:[33]

- Transmission pipelines are designed and operated as if in a Class IV area. Federal regulations would allow the transmission pipelines to be designed and operated as a Class III area.
- PSE&G provides for material and construction quality control not required by federal code:
    - Material Specification Compliance: 100% of the material test reports for steel piping materials are evaluated to ensure compliance with specifications. Steel piping is also visually inspected for quality and condition prior to coating.
    - Steel and Plastic Joint Tests: PSE&G standards provide for the inspection of welded steel and fused plastic joints in pipeline construction activities. The federal code does not require joint testing on pipelines to be operated below 20% SMYS (specified minimum yield strength)[34], which comprises 99% of all PSE&G pipeline construction activity.

Quality Assurance of Design Standards and Codes. Quality assurance or verification of design standards and codes for gas projects are performed as follows.[35]

[33] Response to Discovery, OC-279.
[34] SMYS is the stress value used to calculate the required wall thickness of a pipe that can sustain a certain internal pressure.
[35] Response to Discovery, OC-282.

The Gas Delivery Design Manual is utilized as a guide and reference source by Gas Delivery, who is responsible for the design of the gas distribution systems. Its development and ongoing updates are in close alignment with the federal regulations, specifically 49 CFR Part 192; and reference in the manual to 49 CFR Part 192 is made where appropriate. In addition to providing reasonable and clear explanations for various procedures, the manual encourages the promotion of distribution system uniform design.

The Gas Delivery Gas Distribution Standards Manual is utilized as a guide and reference source for Gas Delivery for both office and field personnel. Similar to the Design Standards Manual, it also incorporates reference to Federal Regulations where applicable. It is also intended to provide reasonable and complete explanations for the various procedures PSE&G requires, openly promoting uniform operations and installations.

Each pipeline operator is required to have a written plan, referred to as Operator Qualifications, or OQ Plan. The plan establishes the operations and maintenance tasks which have been identified as OQ covered tasks. Employees and contractors need to be qualified in accordance with the plan. Records necessary to document qualifications is an ongoing activity.[36]

From 2005 to 2007 standards have gone from all paper-based to an electronic manual, searchable on the mobile data terminals.

In addition to these initiatives, Quality Assurance of design standards and codes is performed by frequent field interaction via monthly meetings where division and field personnel provide feedback on any standard/procedure, with requests for modifications or creation of new standards. Also, quality assurance is performed by the responsible engineer closing out the engineering work order to check for code compliance and project control variances. The division looks at cost variances between the engineering work order actual and estimates on a monthly basis.

System and Capital Planning. System planning begins with analysis of load projects and forecasts that eventually translate into capital investments. System planning is based on criteria and economic analysis to ensure capacity will be provided to reliably supply the gas demand of present and future customers.

PSE&G prepares a detailed five-year capital plan incorporating economic evaluation, budgeting, authorization, fiscal review, and project due diligence.[37] The overall intent of the capital plan process is to consider information required to prepare a financial plan, while ensuring planned projects are needed, economic and appropriate. The process of preparing the budget evolves throughout the year, as new information from various model runs are analyzed to ensure capacity under various design day conditions. Also, investments most needed to keep the distribution system functioning at a safe and reliable level are evaluated.

[37] Response to Discovery, OC-267.

The PSE&G capital process involves multiple layers of analysis, review, approval and monitoring. Since the approach to capital budgeting is similar between Gas and Electric Delivery, please refer to the Electric Delivery and Operations Management chapter for a complete discussion of the capital planning process.

Project Level Process. The safety, reliability, capacity and financial criteria for identifying the capital improvement program, and more specifically individual projects, are directly associated with the metrics of PSE&G's Balanced Scorecard Management Model. Scorecard metrics include the areas of safety, reliability, and financial performance as well as others. Reliability criteria for gas system improvement projects are leaks per mile and cast-iron breaks per mile, while capacity criteria for system reinforcement are maintaining system pressures above the design minimum.[38]

The policies and procedures associated with gas main service and related facilities replacement projects are developed to stay within upper performance limits of leaks per mile and cast-iron breaks per mile. Thus, the results of the main replacement projects are measured by the annual leak and breaks per mile for cast iron and leaks per mile rate for unprotected steel. PSE&G has been able to generally demonstrate a reduced number of main leaks and breaks.

Capacity criteria for system reinforcement projects are the anticipated minimum pressure under design conditions as compared to winter peak-day hour condition. The previously described ongoing network analysis is performed to predict load growth on the system and identify reinforcements needed to maintain system pressures above design minimums.

Work Management. Once worthwhile projects are established for either reasons of reliability, capacity or new growth, construction is planned utilizing a work management system. PSE&G's work management system is referred to as the Distribution Work Management System (DWMS). Utilizing planning tools, the labor and material components for various individual projects are estimated for each work category. Travel time per worker is estimated based on historical hours. The system uses compatible units of which 30% are controllable and consist of items such as inspections and system re-enforcements projects. The other 70% are uncontrollable meaning they are prescribed by others such as DOT, BPU, etc. Plans are reported and viewed by annual, monthly, and weekly reports. A 10% contingency cost is added for project planning.[39]

Within Gas Delivery, employees report their work activities on mobile data terminals using the computer aided dispatch system. Within the application, units completed for each task are recorded on completion records and hours worked are recorded on time sheets.

[38] Response to Discovery, OC-269.
[39] Response to Discovery, OC-246.

In order to attest to the accuracy of the compatible units employed, PSE&G provided summary data for the last five years comparing actual to estimated costs. The following table shows that total actual costs were consistently below plan costs from 2005 through 2008; however, this trend was reversed in 2009 when actual costs exceeded plan costs. This type of fluctuation is well within an overall acceptable variance of 5%.

[Begin Confidential]

Table 20-35 – Estimated and Actual Costs for T&D Field Forces Direct Labor

Public Service Electric and Gas Company Estimated and Actual Costs for T&D Field Forces Direct Labor		
Year	Total Planned Costs	Total Actual Costs
[redacted]		

[End Confidential]

In addition to DWMS, the company continues to move forward with its Graphical Information System (GIS) linking geographical data to specific assets. All or close to 100%, of active gas main sketches an gas service cards have been scanned and are available for viewing in tabular format on the Mobile Data Terminals (MDTs) in company vehicles. The company is using a reconciliation process to link asset information to the features in GIS. The company has 38% of the gas service inventory created in GIS and continues the reconciliation process validating gas service records with customer meter points to link the service card images.

PSE&G created a centralized delivery major project department in 2008 for both gas and electric called Delivery Projects and Construction. This department has approximately 200 employees composed of Overhead, Underground, Relay and Communications craft and technical resources, with a mobile workforce unit agreed to by the union. The mobile relationship between the union and PSE&G is such that employees may cross district boundaries. The Delivery Projects and Construction department is headed by a director and four subordinate project directors. Each project director leads a project team comprised of the following direct reports: inside plant manager, outside plant manager, and ROW/siting and permitting. There are also project control personnel who do not report directly to the project directors. Cost control responsibilities include budget, cash flow, and variance monitoring.

Since the Delivery Projects and Construction department primarily executes and manages projects for Electric Delivery, refer to Electric Delivery and Operations Management chapter for a complete discussion of the Delivery Projects and Construction department.[40]

E. Load Forecasting and the Gas Systems Operations Center

Gas procurement and supply is managed by PSE&G, the regulated utility. However, PSEG Energy Resource and Trading, a non-regulated entity reporting to Public Service Enterprise Group, performs the actual gas supply procurement. The arrangement is described in the Gas Requirements Contract.[41] Consequently, please refer to the Gas Supply, Chapter 3.1.2 for a complete discussion of PSE&G's approach to gas procurement and supply. This section will briefly review load forecasting and the Gas Systems Operations Center.

Load Forecasting. The Company's goal is to manage system demand and gas flows to ensure proper pressure and commodity delivery. To support this effort the Electric and Gas Sales and Forecasting group prepares a long-range plan forecast, a peak day forecast and a daily forecast. PSE&G is also the source of all forecasts regarding the magnitude and location of future gas load growth. Accordingly, the Asset Management group within Gas Delivery prepares a peak hour forecast and a long-term forecast.

1. **Long-range plan forecast** - generally completed in August of each year covering a five-year time span monthly and the next 15 years annually. The long-range plan forecast is based on total throughput of forecasted gas sales. The forecast model takes into account such variables as: rates, customers, weather, economics, pricing, level of employment, and income. The long-range plan forecast is used for business planning financial projections and for Energy Resource and Trading volumes. In addition, the forecast is used as a basis to help confirm expected conditions in the distribution system.
2. **Peak-day forecast** - completed in May of each year, it consists of a regression analysis of daily send out. The peak-day forecast assumes annual load factors are the same, and includes a generated daily guidance based on normal weather. Peak day forecasts are not segregated by rate class and are distributed to Energy Resource & Trading.
3. **Daily forecast** - methodology is to take a monthly forecast, break it down to calendar days, and then factor in normal weather based on regression analysis. Daily forecasts are not segregated by rate class. Distribution of the daily forecast is distributed to Energy Resource and Trading.
4. **Peak-hour forecast** - load estimating and forecasting from a distribution system perspective to see if the distribution system can physically handle the maximum load anticipated.
5. **Long-term forecast** - load estimate and forecast for the next five years by year and the 10th year from a distribution system perspective to see if the distribution system can physically handle the

[40] Response to Discovery, OC-625.
[41] Response to Discovery, OC-216.

maximum load anticipated and determine where best to add new supply sources if required. If any supply limitations are indicated, then it would review the data with Energy Resource & Trading.

Gas Systems Operations Center. The Company maintains an organizational unit known as Gas Systems Operations Center. As the name implies this organization is responsible to operate the gas system.

The organization structure within the Gas Systems Operations Center consists of a SCADA group, a control/operator group and a gas analyst group. The control/operator group is the largest group with 15 employees and work 24/7. The analyst group consists of five personnel, four of which are devoted to manning the third-party desk.

The Manager, Gas Systems is responsible for operating the system by ensuring proper pressure and commodity delivery. This group is also responsible to provide by 7 AM each morning a priority sheet indicating the gas volumes required by hour for the next 24 hours. This daily load forecast is given to Energy Resource & Trading. Of course, on weekends this becomes a three day daily load forecast day requirement. Energy Resource & Trading, as a supplier of last resort, is required to meet all system send out needs except for LNG. LNG remains under the control of the utility. All other storage type assets are under Energy Resource and Trading control. Software used to perform this function was internally developed to look for similar days and track actual versus expected send out.

21. CONTRACTOR PERFORMANCE

Introduction and Summary

This chapter addresses PSE&G's Contractor Performance. Topics reviewed and evaluated include: the excavation damage program, field audits conducted at contractor facilities, accuracy of mark outs, management of outside contractors, project management approach, contractor performance, and contractor inspection procedures.

Summary of Findings

1. All damage prevention locates are performed by PSE&G employees, resulting in the Company taking "site ownership" and achieving significant reductions in third-party damages.
2. Field audits are completed quarterly for all locators normally assigned to perform locates; the audit process includes verification of the marks and accuracy of the documentation; results are documented and shared as lessons learned.
3. From 2004 through 2009, Gas and Electric Delivery has reduced the total number of damages to its distribution system by 44%.
4. In 2008 PSE&G formed the Delivery Projects and Construction (DP&C) organization. Included within this group is a project management/control's structure, a mobile construction workforce, a work integration group and safety oversight.
5. In connection with outsourced construction activity, PSE&G ensures and monitors the quality of its contractors' performance using a thorough Project Construction Oversight process for larger projects.
6. Procedures are in place to ensure system safety is ultimately PSE&G's responsibility, regardless of whether a contractor performs the work or not.
7. More standard and smaller projects are routinely initiated and managed within Gas Delivery or Electric Delivery, while larger more complex and specialized projects are managed by Delivery Projects and Construction.
8. PSE&G utilizes its internal workforce for the majority of its activities.

Background

PSE&G utilizes its internal workforce for most gas distribution activities. However, Gas Delivery will outsource construction activities for a number of reasons, including availability and complexity of the proposed work. There are a number of areas where the Company has found it beneficial to outsource a portion of its work activity. These areas include: new business construction, replacement facility construction, replacement in connection with the Capital Infrastructure Investment Program, and to a far lesser extent, the outsourcing of specialized engineering/design and operation and maintenance work.[1]

PSE&G has several processes in place to ensure proper management of outside contractors. In Gas Delivery, a bid is prepared which details the work to be performed. The award is based on low-cost as determined through unit costs submitted by the contractor in response to company-estimated quantities of work to be performed. On large construction projects an enhanced program management process is used to ensure full compliance with project work scope, execution plan, budget, schedule and all contractual obligations.

One area where the Company has chosen not to outsource is in connection with third-party mark-outs. PSE&G's approach to damage prevention is to perform all locates in-house.

Damage Prevention Program

PSE&G's damage prevention program and procedures are aligned with the Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) Pipeline Operator Public Awareness program, implemented in 2006. PSE&G's Damage Prevention program is defined as the active promotion of awareness and protection of underground facilities from accidental damage during excavation.

PSE&G's approach to damage prevention is to perform all locates in-house. In 2002 they reached agreements with the union to send one person to do both electric and gas mark-outs. Consequently, the mark-out employees take site ownership for both utilities (spray and stay). As a result of instituting this practice, along with working within a familiar geographic area and getting them involved with job planning, they have reduced damages for both electric and gas from 1,276 in 2002 to 762 in 2009.[2]

The processes used to mark buried electric and gas facilities and associated documentation and record keeping is as follows.[3] PSE&G locators are instructed to perform a visual review of the requested locate area upon arrival, and a review of available facility records, prior to locating any facility. Upon completion of the site review and facility records, locators will attempt to locate facilities via one of the following methods, listed in order of preference: direct connect to facilities or locate wire; induction via clamp; or broadcast induction. Upon completion of the locate request, locators will complete required fields associated with the electronic records, documenting the method used to complete the locate, time/date, and note unusual field conditions. For QA/QC, PSE&G performs random checks on locates, which are captured on a database that stays open until the individual corrects the mistakes. Should a facility be struck, the determined root cause of the damage will determine if the individual third-party will be billed or not billed for the damage.

[1] Response to Discovery, OC-242.
[2] Response to Discovery, OC-849.
[3] Response to Discovery, OC-297.

PSE&G performs field audits on completed locates.[4] The field audits are completed quarterly for all locators normally assigned to perform locates; the audit process includes verification of the marks and accuracy of the documentation; results are documented and shared as lessons learned. PSE&G uses the Mark-out Field Quality Assessments Database program to perform damage prevention field audits. Field Quality Assessments (FQAs) are completed on approximately one percent of completed locates. The FQA's are completed as follows:[5]

- One FQA per quarter for each regularly assigned mark-out inspector.
- One FQA per week to be completed on locate requests generated for PSE&G construction crews.

Results from the FQA's are entered into an access database and reviewed quarterly. Lessons learned are generated monthly based upon reviews of the FQA's and damage investigations. The lessons learned are then shared in scheduled monthly meetings with all locate inspectors, or worked into the annual refresher training given to each locate inspector.[6] PSE&G looks for improvements via lessons learned, and conducts monthly meetings with inspectors to review the scorecard, damages, lessons learned and QC inspections review. They perform root-cause analysis jointly with the field to lower damages and track damages by municipalities and form a list of selected excavators to be trained. Damage rates by districts are visible on the scorecard to the board of directors.

The process of dealing with problem excavators is as follows: first, the crew is approached and told of the problem; second, someone is placed to watch over them at their cost under an "umbrella of safety." The BPU is forwarded damage reports and is supportive of going after reckless excavators with fines. The Company meets quarterly with the BPU to discuss damage prevention. As a last resort local authorities are used, if needed, to manage reckless third-party excavation crews.

Damage Prevention Best Practices[7]

PSE&G is aligned with many of the best practices identified by the Common Ground Alliance (version 6.0). Particularly noteworthy practices include the sharing of utility location during the design phase of construction projects; proactive public awareness education and outreach to excavators; work site reviews with excavators; locating multiple facilities with one locator; and active damage recovery. Statewide root-cause analyses are reviewed monthly on a case by case basis, and as described above, are shared with PSE&G locators during monthly review sessions.

Damage Trends

The following details the combined electric and gas damage trends for the past five years:

[4] Response to Discovery, OC-240.
[5] Response to Discovery, OC-311.
[6] Response to Discovery, OC-311.
[7] Response to Discovery, OC-294.

Table 21-1 – Combined Electric & Gas Damage Rate and Damages

Public Service Electric and Gas Company Combined Electric & Gas - Damage Rate and Damages		
Year	Damage Rate	# of Damages
2004	2.79	1,357
2005	2.69	1,349
2006	2.30	1,232
2007	2.17	1,145
2008	1.77	967
2009	1.51	762
Response to Discovery, OC-849		

Since 2004, Gas and Electric Delivery has improved its combined gas and electric process damage rate by 46% from 2004 through 2009, and has reduced the total number of damages for the same period by 44%.

Damage rate and the number of damages are the primary metrics reviewed monthly by PSE&G. There are several other measures, some of which appear on the monthly scorecard, which are analyzed against targets and historical trends. Some of these measures include cost per unit, classification of damages for fault (operator versus excavator), and damage summaries by municipality.

PSE&G has had good success in its Mark-Out Location of Buried Facilities program. The following table describes the last five years results for the various programs to maintain underground facilities from being hit or damaged by third parties. The table includes: a) number of mark-outs requested; b) number of company employees performing this function; c) actual yearly costs to perform mark-outs; d) number of events resulting in damage to facilities attributable to the Company; e) number of events resulting in damage to facilities attributable to excavation contractor error.

Since damage prevention is managed within the PSE&G organization for electric and gas combined, the information provided in the below table represents combined electric and gas information, and illustrates improvement in program performance.

Table 21-2 – Mark-out Programs – Combined Gas and Electric

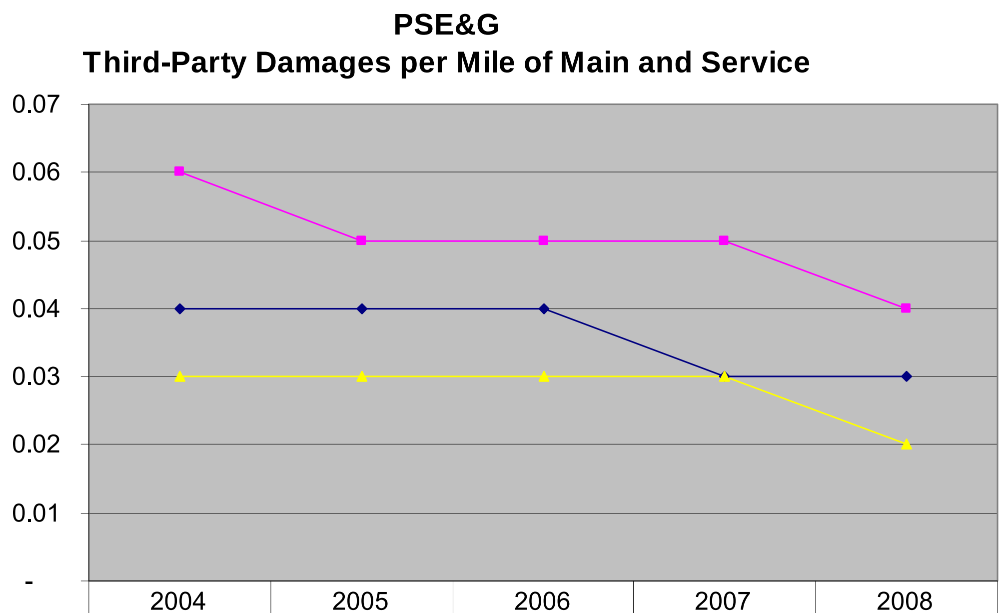
Public Service Electric and Gas Company Mark-Out Programs - Combined Gas and Electric					
Year	Number of Mark-Out Requests	Number of Company Personnel Assigned	Actual Annual Costs to Perform Markouts (Millions)	Number of Damages Incurred Due to Company (Operator Error)	Number of Damages Incurred Due to Excavator Error
2005	500,854	Averages between 85-95 people, varying depends upon workload volume received during the year.	$15.6	215	1,134
2006	535,786		$16.5	209	1,023
2007	526,859		$17.2	195	950
2008	545,974		$19.0	203	764
2009	505,805		$18.2	190	572
Response to Discovery, OC-848					

The data reveals that the number of mark-out requests has averaged approximately 522,000 mark-outs per year with a peak of 546,000 being reached in 2008. During that same time period, damages incurred due to PSE&G locate inspector error were reduced by over 11% from 215 to 190, despite an increase of 5000 mark-out requests. Even more dramatic improvement has been shown in the number of damages incurred due to third-party error. In 2005, 1,134 damages by the excavator occurred; this number was reduced to 572 in 2009 for an almost 50% improvement.

Benchmark Comparison

PSE&G's Damage Prevention program compares well against the PSE&G defined peer panel of 30 companies. To graphically display this comparison, two charts will be presented, first, Table 3, Third-Party Damages per Mile of Main and Service, and second, Table 4 Damages per 1000 Locates. For Third-Party Damages per Mile of Main, the Company was able to achieve first quartile performance in every year of the five years of the comparison. For Damages per 1000, the Company has been consistently improving, and in 2008, came very close to achieving first quartile performance compared to the benchmark panel.

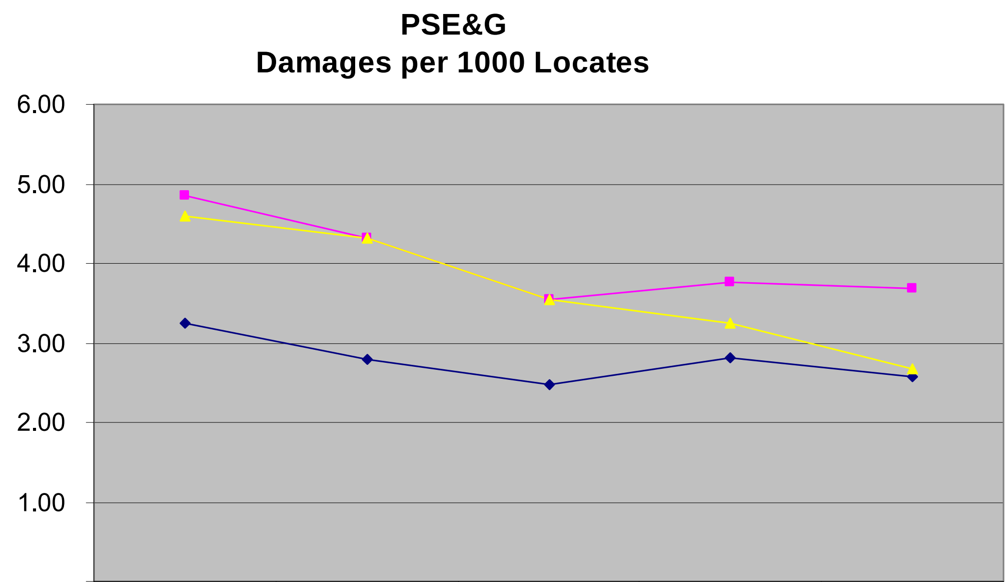
Table 21-3 – Third-Party Damage per Mile of Main and Service



	2004	2005	2006	2007	2008
1st Quartile	0.04	0.04	0.04	0.03	0.03
Median	0.06	0.05	0.05	0.05	0.04
PSE&G	0.03	0.03	0.03	0.03	0.02

Source: PSE&G's data - 2008 Gas Data Blinded.pdf - Page 5

Table 21-4 – Damages per 1000 Locates



	2004	2005	2006	2007	2008
1st Quartile	3.25	2.80	2.47	2.81	2.57
Median	4.85	4.32	3.54	3.76	3.69
PSE&G	4.59	4.32	3.54	3.24	2.68

Source: PSE&G's data - 2008 Gas Data Blinded.pdf - Page 5

Management of Outside Contractors

Organization for Large Projects

In 2008, PSE&G formed the Delivery Projects and Construction (DP&C) organization. Included within this group is a project management/control's structure, a mobile construction workforce, a work integration group and safety oversight. This organizational re-staffing was an attempt to instill a more rigorous project management approach within the Company. As part of the project management approach, a functional group was staffed under a Manager of Transmission Projects to manage large 500 KV transmission projects, while another group under the Direction of a Manager of Projects was put in place to manage the remaining portfolio of gas and electric projects. A separate project controls group was established to facilitate cost control and schedule development.

This organization is currently evolving through a multiyear implementation plan. In the first quarter of 2009, workflows were put together for cost control, scheduling, scope management, and estimating with the expectation of enhanced project execution. The processes that were developed to support a more detailed project management approach are embodied in a document entitled Project Construction Oversight dated June 9, 2009. Later in 2009, the Company introduced an enhanced vendor invoice management process and initiated design requirements for Primavera P6 software. Full implementation of the Electric Delivery Project Portfolio is scheduled for the end of 2010.[8]

The use of Primavera P6 is needed to overcome certain limited functionality that exists in Primavera P3 and Microsoft Project platforms. Limited functionality includes the ability to provide timely and relevant project portfolio and individual project schedule and cost performance information. In addition, there was no link between Primavera P3 and Microsoft Project and the Corporate Enterprise Financial Accounting system, limiting the ability to fully integrate cost and schedule information needed for effective cost control oversight. PSE&G anticipates this software will provide a critical integration of budget and schedule information essential to support overall planning, execution, monitoring, and control of Electric Delivery projects.[9]

Currently, the DP&C group uses four reports to monitor projects. These reports and a brief description of their use are as follows:[10]

- Transmission Capital in Service Report - used to manage transmission assets placed in service against annual FERC filing submissions.
- Current Capital Performance Report - used to evaluate cost and schedule performance of projects against targets. Report lags actual by one month.
- Capital Project Results Report - used to measure project management effectiveness by measuring capital resources deployed to achieving a desired project outcome. Project Closeout Report is input to this metric.
- Forecast Variance Report - summarizes monthly forecast variances by large projects where the variance is greater than $100,000 in a given month. Analysis of the variances resulted in initiation of corrective action.

In order to establish an estimated cost for large projects each project goes through a four-stage risk analysis and contingency assignment as follows:[11]

- Office Level Estimate (less than a 50% confidence level) - very preliminary estimate used for long-term planning purposes. Typically office level estimates have little or no field investigation.
- Study Level Estimate (50% confidence level) - project is at the very early stage of development and detailed information about the project is not yet available.

[8] Response to Discovery, OC-486.
[9] Response to Discovery, OC-485.
[10] Response to Discovery, OC-627.
[11] Response to Discovery, OC-628.

- Conceptual Level Estimate (70% confidence level) - project details provide more definition with the project's design, materials, and labor requirements evaluated.
- Definitive Level Estimate (90% confidence level) - design and engineering complete, major equipment ordered, construction contract pricing received, land acquired and most permits are in hand. The remaining unknowns may include certain activities and materials yet to be ordered.

Utilizing the above phased estimating approach we requested a list of the 10 largest projects initiated by PSE&G in the last three years. The list was to include the date of the initial estimate and the amount, date of the final estimate and the amount, and if the project was still ongoing, the actual costs accrued to date as well as an assessment as to whether the project is below budget, at budget, or over budget and why. The Company provided the following table of projects and their status.[12]

Table 21-5 – List of 10 Largest Projects

PSE&G
List of 10 Largest Projects

PM	Project	No	Initial Forecast ($M)	Phased Funding Project**	Approved Funding Request	Initial Forecast Approval Date	Current Forecast ($M)	Current Forecast Approval Date	Final Forecast ($M)***	Final Forecast Approval Date***	Complete / Ongoing	PTD thru Jan 10 ($M)	Below / At / Over Budget	Budget Comments
Brauchle	b0829-b0836 Garden State Reliability Project	Office	1,088.0	Yes	8.0	Dec. 2009	1,088.0	Dec. 2009	NYA	NYA	Ongoing	3.240	At Budget	Project is in Preliminary Engineering Phase.
Ribardo	b0489 - susquehanna - Roseland 500kV Project	Conceptual	750.0	Yes	207.1	Jul. 2009	750.0	Dec. 2009	NYA	NYA	Ongoing	44.010	At Budget	Project is in Detail Engineering Phase.
Alvarez	Bergen - River Rd - E. Rutherford 69-kV Ntwk	Office	144.3	Yes	1.5	Sep. 2009	144.3	Dec. 2009	NYA	NYA	Ongoing	0.485	At Budget	Project is in Preliminary Engineering Phase.
Yarmany	b0290 - 400MVARs of Capacitor Banks Branchburg 500 kV	Study	105.0	Yes	15.2	Dec. 2009	105.0	Dec. 2009	NYA	NYA	Ongoing	1.977	At Budget	Project is in Detail Engineering Phase.
Strauss	b0814 - New Essex-Kearny 138 kV circuit and Kearny 138 kV bus tie	Study	71.1	No	71.1	Dec. 2009	71.1	Dec. 2009	NYA	NYA	Ongoing	0.215	At Budget	Project is in Preliminary Engineering Phase.
Barton	Runnemede 26kV to 69 kV Conversion	Study	69.6	No	69.6	Dec. 2009	69.6	Dec. 2009	NYA	NYA	Ongoing	0.585	Below Budget	Bids for station engineering came in lower than expected.
Tkachuk	Bennetts Lane - Lawrence 69-kV Network	Study	75.8	Yes	41.7	Oct. 2008	75.8	Oct. 2008	NYA	NYA	Ongoing	8.671	At Budget	Outside Plant is in Construction phase, Inside Plant is in Preliminary engineering phase.
Alvarez	Bergenfield Class H Substation	Study	55.5	No	55.5	Dec. 2009	55.5	Dec. 2009	NYA	NYA	Ongoing	0.444	At Budget	Project is in Preliminary Engineering Phase.
Tkachuk	Reinforecement of Deptford Substation	Study	47.7	No	47.7	Dec. 2009	47.7	Dec. 2009	NYA	NYA	Ongoing	0.101	At Budget	Project is in Preliminary Engineering Phase.
Leonards	Bennetts Lane - Bridgewater 69-kV Network	Conceptual	58.8	Yes	16.0	Apr. 2009	44.0	Dec. 2009	NYA	NYA	Ongoing	4.787	Below Budget	Market conditions are resulting in more favorable pricing from contractors and suppliers.

Source: Document Request - OC-484.pdf - Page 2

***Estimate Phases**
Office - Less than 50% CL
Study - 50% CL
Conceptual - 70% CL
Definitive - 90% CL

****Phased Funding:** Projects that are identified as complex, high cost, long duration or "fast track" projects may follow the phased project funding approach. The phased funding approach is designed to incrementally fund a project and thereby control the Company's financial exposure over the lifecycle of the project. Funding is typically requested to cover engineering and material commitment cost to deliver the project to the next estimate phase.

*****Final Forecast and Final Forecast Approval Date:**
NYA = Not Yet Available. All projects listed are ongoing and in various early phases of the project lifecyice and therefore final project estimated/forecasts are not yet available.

Projects listed in the table were approved here in 2008 or 2009. Two of the projects are at the office estimate level, six are at the study estimate level, and two are at the conceptual level. Due to the relatively early stages of the projects, the current forecast is identical to the initial forecast except for project #10, which is a conceptual estimate. In this project the estimated cost of $58.8 million has been

[12] Response to Discovery, OC-484.

reduced to $44 million as a result of more favorable market conditions for pricing of materials, equipment, and contracts.

Large Gas Projects Managed by Delivery Projects and Construction

In connection with outsourced construction activity, PSE&G ensures and monitors the quality of its contractors' performance via the Project Construction Oversight process for larger projects. The Construction/Services Vendor Evaluation Report from SAP (Rev. 11/26/02) is used to evaluate contractors involved in smaller projects. In addition to the working inspector doing QA/QC, there is an inspector planner who lays out the job and plans the work via computer.[13] The following details the Contractor Oversight process as presented in PSE&G's Project Management Procedures.[14]

Contractor Project Schedule Oversight

Contractors are required to prepare and submit a detailed contract-specific construction schedule for review and approval; in general, within two weeks of notification of award unless otherwise specified. A project controls engineer will then incorporate the contractor's construction schedule into the Integrated Project Schedule, and ensure it aligns with other project, vendor, and contractor schedules. The contractor will update the contract schedule with actual progress on a monthly basis, or as requested, and submit the updated schedule for review and approval. As specified in the contract documents and in the Project Execution Plan, the contractor is responsible for providing periodic status and progress reports. The Project Controls Engineer will track progress against the Integrated Project Schedule to ensure the overall project remains on schedule. The contractor will notify the designated PSE&G representative immediately of any schedule delay, work delay, conflict, equipment, or material shortage, or other occurrence that calls for a schedule change.

Contractor Project Work Plan and Schedule Requirements

The contractor must prepare and submit a detailed work plan, on a weekly basis or at other intervals specified in the Project Execution Plan, to the project manager for review and approval. The work plan must set forth and describe work to be performed, and will be aligned with the contractor's construction schedule and integrated project schedule.

Field Status Monitoring

PSE&G field verifies reported contractor progress against contractor work plans, schedules, and the project plan schedule. A *Project Quality Management Tracking Form* is used to track project quality and document any noncompliance issues and their impacts.

PSE&G inspectors use field-generated field tracking forms, construction reports, receiving reports, and invoice records to document field-completed activities and deliverables. For internally managed

[13] Response to Discovery, OC-242.
[14] Response to Discovery, OC-242.

contracted projects, designated Delivery Projects and Construction (DP&C) representatives will track labor hours worked on the project site on a weekly basis, and record these hours in the construction report. All received goods and services for payment purposes are also documented.

Inspection and Verification of Material Supplier Deliverables

A PSE&G representative maintains a record of all contractor-supplied material and equipment delivered to the project site, including quantity and date of delivery. This is accomplished by thoroughly inspecting all contractor-supplied material and equipment at the time of delivery, verifying that it is in proper and undamaged condition, and conforms to contract documents. A delivery of contractor-supplied material and equipment that is either damaged, incomplete, does not meet specifications for quality, or is otherwise not in compliance with contract documents, will be returned or set aside and resolved in accordance with contract requirements. For EPC managed projects, it is the responsibility of the project manager to ensure that the EPC contractor completes the inspection and provides verification requirements.

Verification of Quality and Quantity

PSE&G monitors and verifies the quality of contracted labor, workmanship, materials, and equipment for the project. PSE&G representatives routinely observe contractor workmanship, inspect installed material and equipment, and provide feedback to the Project Manager and to the contractor on the skill, expertise, and craftsmanship of the contracted labor/craft force in performing project tasks. If deficiencies in the quality of the final product are identified, the PSE&G representative immediately notifies the project manager and the contractor of the findings. The contractor must correct the deficiencies or seek resolution in accordance with established procedures.

PSE&G monitors and verifies the quantity of contracted labor hours, materials, and equipment for the project as required by contract type. At intervals and under conditions set forth in the contract documents, designated DP&C representatives will monitor quantities for all material, consumables, and equipment delivered and installed by contractors, and verifies that these quantities are correct pursuant to contract requirements. PSE&G team members and the contractor are notified when quantities of acceptable materials, consumables, and equipment fall short of their required number or volume. The contractor must correct the shortfall or seek resolution in accordance with established procedures.

Change Order Requests

The contractor must notify PSE&G of a pending change request, and provide a written request that documents the reason for the change with supporting facts. The PSE&G representative will determine the validity of the change request, assess its impact on the project scope, cost, and schedule, and review the request as appropriate with the construction manager or project manager.

Safety Performance Verification

Procedures are in place to ensure that contractor safety performance is ultimately PSE&G's responsibility. It is the responsibility of the Project Manager to designate one or more representatives, as the project requires, to monitor and verify the safety performance of the project and contractor workforce. It is the responsibility of the PSE&G representatives to review and fully understand the safety requirements of the contract and the project. Qualified and designated PSE&G representatives field monitor and verify the safety performance of the contractor workforce to ensure that it complies with all existing site, contractor, PSE&G, and OSHA requirements. These verifications will include, but not be limited to, safety watcher checklists, tailboard meetings, and contractor safety reporting.

Invoice Accuracy Oversight and Contract Closeout

Invoice validation is the process of verifying that the goods and services reported on a submitted invoice have in fact been provided as reported. PSE&G will not approve an invoice for payment until it has been validated.

Upon successful project completion, designated PSE&G representatives conduct a final project acceptance inspection. This inspection includes a punchlist of necessary corrective measures and actions and outstanding items as appropriate. PSE&G also verifies that the contractor has corrected any and all deficiencies in a timely manner before final invoice payments are approved. PSE&G verifies the contractor has performed final site cleanup of all contractor-owned equipment and materials, and has restored the site to its original condition or to the requirements set forth in the contract documents. PSE&G completes an evaluation of the contractor's performance for any contract that exceeds $100,000 in accordance with the established procedures.

Projects Managed within Gas Delivery or Electric Delivery

More standard and smaller projects are routinely initiated and managed within Gas Delivery or Electric Delivery, while larger more complex and specialized projects are managed by Delivery Projects and Construction. The gas distribution districts manage the execution of the contractor work. While Procurement awards the contractor based on bid and qualifications and conducts a pre-bid meeting.

The approval process includes Supply Chain Management receiving a contractor's letter of interest showing proof of meeting PSE&G's insurance requirement, medical plan, safety plan, and evidence of the contractor's OSHA Rate and Fatality Rate.[15] Also, for Gas Delivery an Operator Qualification Plan by individual for the categories of steel, plastic and welding is needed. Contactors can qualify to the PSE&G Qualification Plan. The contractor's training is audited by PSE&G, as well as equipment needs, and internal and third-party certifications. Operator Qualification is also audited by observing quality of work, and adherence to PSE&G's safety and standards. Also, PSE&G medical personnel audit the drug and alcohol plans and records.

[15] Response to Discovery, OC-242.

DP&C's Technical Support carries out state-level random checks, and the BPU also performs random checks with PSE&G present. Contractors failing to meet requirements are suspended. If improvement is noted, contractors that have been suspended from bidding will regain eligibility.

Inspecting Contractors

When outsourcing gas or electric construction work, PSE&G Gas Delivery or Electric Delivery will assign a representative to oversee construction work being performed by a contractor. A representative will inspect work being constructed as part of their daily responsibilities.[16] The representative will prepare a bid and daily form as work is completed to document acceptance of construction. The working inspector oversees crews (1 or 2 only) and reports back to a supervisor on a daily basis concerning Quality, Quantity, and Schedule.

Level of Outsourced Work

Both Gas Delivery and Electric Delivery utilize outside contracting services to support the design, construction, operation, maintenance, and repair of the gas and electric transmission and distribution systems.

The Company utilizes its internal workforce for the majority of its activities. The table below describes for various gas and electric activities the approximate level of outsourcing in 2008.[17]

Table 21-6 – Various Gas & Electric Activities

Activity	For the Year 2008
Gas - new business construction	21%
Gas - replacement facility construction	58%
Gas - operations and maintenance	3%
Electric - capital work	62%
Electric - operations and maintenance	25%

- Both Gas Delivery and Electric Delivery maintain a trained and experienced internal workforce with skills necessary to perform required work activities. Much of the contracting levels above represent work required at peak periods, or on large or specialized projects. The Electric - operations and maintenance is primarily due to tree trimming activities. In 2009, capital levels for both electric and gas replacement facility construction increased due to an accelerated capital infrastructure investment program, approved by the New Jersey Board of Public Utilities (BPU). Federal regulations allow for every three years, or every five years based on the type of material.

[16] PSE&G's Gas Distribution Standards, Part Four, Chapter Seven, Inspections.
[17] Response to Discovery, OC-241.

- Distribution Leakage surveys of services is done every three years. Federal regulations allow every five years based on the type of material.
- A Winter Patrol Leakage survey is conducted during periods of severe winter weather over mains in business areas and other select locations. This survey is not required by federal regulation.
- Public Building Inspections are performed every three years versus five years for leakage surveys required by federal regulations. The inspections include the following actions that are not required by regulation:
  - Determination of curb valve accessibility.
  - Testing of atmosphere of the curb box with a combustible gas indicator.
  - Placement of the valve key on the outside shutoff to assure proper fit.
- House Heater Periodic Inspections are performed on customer owned equipment to ensure a safe operation.
- Transmission pipelines are surveyed for leakage twice a year versus once per year by federal regulations.
- PSE&G provides for material and construction quality control.
- Material Specification Compliance: 100% of the material test reports for steel piping materials are evaluated to ensure compliance with specifications. Steel piping is also visually inspected for quality and condition prior to coating.
- Steel and Plastic Joint Tests: PSE&G standards provide for the inspection of welded steel and fused plastic joints in pipeline construction activities. The federal code does not require joint testing on pipelines to be operated below 20% SMYS (Specified Minimum Yield Strength), which comprises 99% of all PSE&G pipeline construction activity.
- Gas odorant testing (odorant control) is conducted on a monthly basis.
- Gas analysis is conducted on a monthly basis to ensure gas quality from gas suppliers, system operations, and peaking plant operations.

22. Customer Service and Meter Reading

Customer Service, unlike many other back-office administrative functions, is part of the PSE&G organization. It is headed by Joseph Forline, Vice President – Customer Operations.

During the audit period, the matter that dominated the attention of this organization was the replacement of its 28-year-old legacy customer information system. After over two years of planning, PSE&G "cut over" to its new SAP-based customer information system in early 2009. This significant system conversion and its aftermath are discussed in more detail later in this chapter.

Summary of Findings

1. The Customer Operations organization of PSE&G encompasses most traditional customer service functions except for appliance services, which is housed within PSE&G Gas Delivery. The head of the Customer Operations organization reports to Ralph LaRossa, President & COO of PSE&G.

2. During merger negotiations with Exelon between 2004 and 2006, PSE&G and Exelon decided to abandon the PSE&G customer information system on a prospective basis and use Exelon's system instead. When the merger was called off in late 2006, PSE&G convened a team to look into its options with respect to the customer information system absent Exelon. The team recommended and management adopted a plan to pursue an integrated customer service platform. A major component of this project was the replacement of the legacy 28-year old PSE&G customer information system with a new system designed by SAP.

3. The integrated customer service platform project (commonly referred to as iPower) not only included the replacement of the customer information system but also the upgrade of the interactive voice response unit, a new self-service website, new hand-held devices for field collectors, and electric meter technicians and other systems enhancements.

4. The perceived success of the iPower project roll-out was mixed. Even though the company won industry awards and peer company accolades for its iPower implementation and successfully brought the project to conclusion under budget, the company was less effective in managing the expectations of key groups. Company management, the PSEG Board of Directors, customers, the news media, and BPU Staff all expressed various levels of displeasure with the iPower implementation and its effect on customers.

5. While customer service performance temporarily dipped due to the conversion to a new customer information system, many performance metrics have eventually returned to steady state levels.

6. Advanced metering infrastructure has been considered by PSE&G in the past, but current economic conditions have delayed a long-term, system-wide implementation of the technology.

7. As with other organizations within consolidated PSEG, the performance of Customer Operations is measured through a balanced scorecard process. Compared to other organizations such as Finance,

Customer Operations (as a whole) chose to report a significantly greater number of performance metrics.

8. Customer Operations' balanced scorecard results in 2009 showed many instances of under-performance. One likely explanation for this under-performance is the roll-out of the customer information system in April, 2009 and the subsequent "dip" in service.

9. Benchmarking of customer service functions was obtained from two different sources – a survey sponsored by PSE&G and another conducted by PA Consulting. Overall, we concluded that PSE&G's performance in both surveys was average at best. We attribute this to data that (at the time) did not reflect a resumption by PSE&G to steady-state performance post-iPower implementation, unfavorable cost comparisons that result from operating in a service territory with a high cost of living, and a relative lack of automation in terms of advanced metering infrastructure.

10. PSE&G contracts with two outside agencies to perform an assessment of customer satisfaction using two different measurements – a Customer Perception Survey and a Moment of Truth survey. While relative measurements of satisfaction based on residential customer perceptions slipped slightly in the third quarter of 2009 from previous years, they were much higher than the relative perceptions of small business customers. PSE&G was ranked below average in 13 of 33 categories by small business customers in the third quarter of 2009. PSE&G fared even worse with customers who reported their satisfaction based on actual experience with the call centers and customer service centers in the second quarter of 2009 (Moment of Truth surveys), the most recent data made available to us. PSE&G has assigned the task of improving customer satisfaction to Perception Working Teams.

11. While PSE&G attempts to read most meters on a monthly basis, it offers its customers the option of calling in their meter reads. Customer reads are generally subject to validation to ensure that the implied usage being reported is reasonable. Usually the customer is informed that this validation process has taken place before the customer-reported read is accepted, but in some cases, the customer is unaware that his/her reading will be rejected.

12. During portions of 2009 and 2010, PSE&G acknowledged that its interactive voice recognition system and website were not properly handling some customer-submitted meter read data. In those cases, the meter read data was not used for billing purposes. The company asserted that this system defect was corrected in November 2010. However, we did not independently verify this assertion.

13. PSE&G operates call centers from three locations in New Jersey. The General Inquiry Call Center, which handles emergency calls, operates form two locations. This reduces the risk that one event can render all call center functionality inoperable. Inbound overflow is handled by AT&T using a voice response unit. The number of personnel assigned to call centers has increased between 2007 and 2010 as the company attempts to minimize customer wait times.

14. PSE&G has taken several steps to ensure that customers who do not speak English as a first language are able to receive assistance in their native tongue when they call the company's call centers.

15. With the introduction of web self-service as part of the iPower roll-out, more and more customers are electing to receive their bills electronically. The company expects the number to double from 3.6 percent to 8 percent between mid-2010 and year-end.

16. The terms of deferred payment arrangements (DPAs) requested by residential customers are dependent on their payment history. Customers who have not broken a DPA in the previous twelve months are asked to make a down payment up to 25 percent of the outstanding balance. Customers who have broken a DPA in the previous twelve months but whose service has not been shut off must make a down payment of no less than 75 percent of the outstanding balance. A customer who has both been shut off and broken a DPA in the last twelve months will need to post 100 percent of the total outstanding balance in order for service to be restored. The duration of DPAs is more subjective and is based on such considerations as amount owed, prior payment history, and sources and timing of income.

Recommendations

1. The company should consider limiting the number of balanced scorecard metrics tracked for major functional areas (e.g., Finance, Customer Operations, etc.) to those most critical to the assessment of the entire organization.

2. In the short term, PSE&G should take the necessary steps to improve customer satisfaction so that it meets or exceeds levels measured prior to the iPower project implementation. In doing this, the underlying metrics that most impact customer perceptions (e.g., wait times, first call resolution, etc.) should also improve. In the long run, the achievement of top quartile ratings should be the goal as is the case for most operating statistics.

3. A meter reading submitted by a customer using the interactive voice response unit should either be subject to immediate validation (just as customer reads submitted on-line or with CSRs are), or the customer should be informed that his/her reading is subject to eventual validation and will not be used if it is unreasonable. Currently, PSE&G can reject a customer meter reading without the customer ever being informed of this decision.

Organization and Staffing

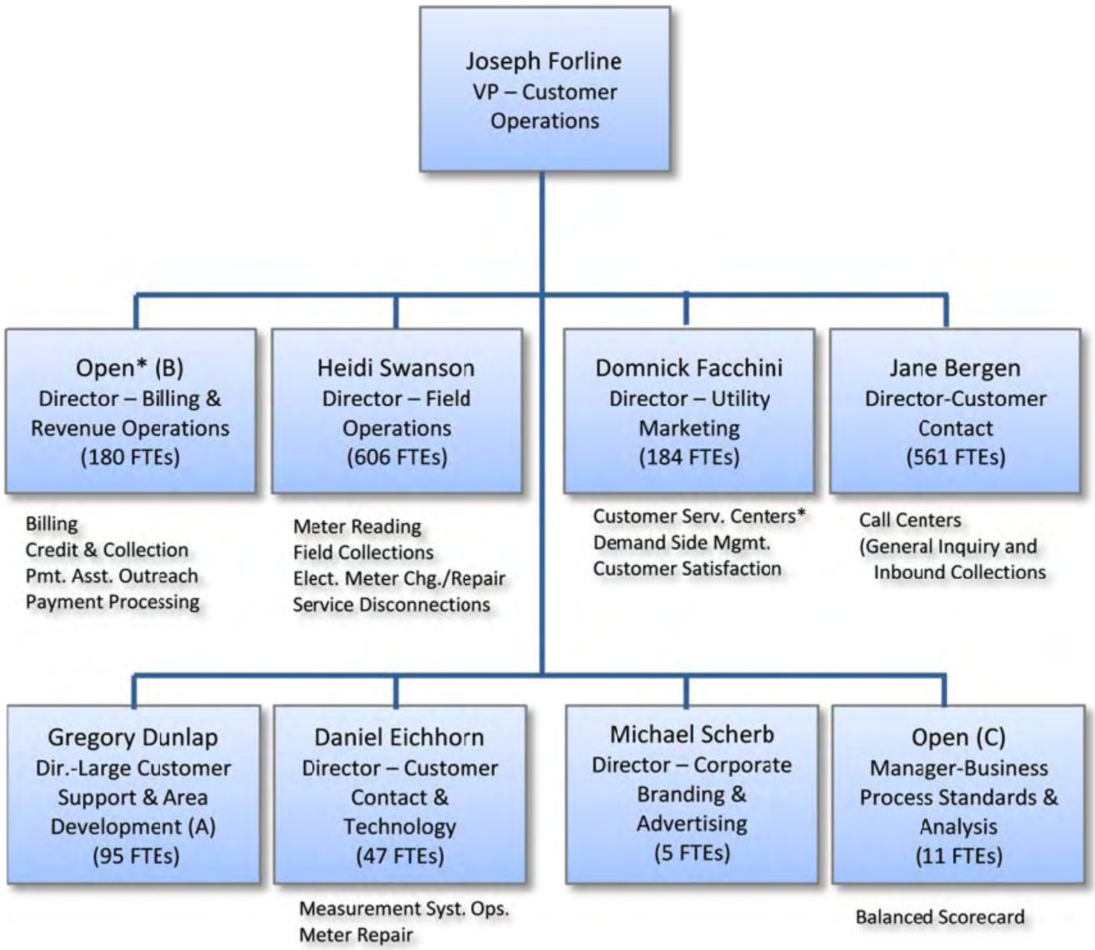
The Customer Service organization[1] is headed by Joseph Forline, Vice President – Customer Operations of PSE&G, who assumed his current responsibilities in December, 2006.[2] Mr. Forline reports to Ralph LaRossa, President & COO of PSE&G, who in turn reports to Ralph Izzo, Chairman, President & CEO of PSEG. The Customer Service organization as of September, 2010 was structured as follows:[3]

[1] The company refers to customer service as Customer Operations. These two terms are used interchangeably in this chapter.

[2] Executive profile posted on the PSEG website.

[3] Responses to Discovery, OC-1270 and OC-73 and interviews with Joe Bassolino, Manager – Business Development (Appliance Services) and Robert Blache, District Manager – Gas Distribution & Appliance Services, on August 19, 2010; and Vic Viscomi, Director – Projects, and Mike Kelly, Manager – Operations – Billing, on August 18, 2010; and Dave Daly, Vice President – Asset Management & Centralized Services, on September 2, 2010.

Table 22-1 – Customer Service Organizational Chart



*Domnick Facchini assumed responsibilities on a temporary basis.
(A) Area Development Department eliminated as of October 18, 2010 (per response to Discovery, OC-1213)
(B) As of July 7, 2011 Jane Bergen is Director – Billing, Revenue & Controls
(C) As of July, 7, 2011 Bill Sharlow is Manager – Business Solutions. Mr. Sharlow reports to Jane Bergen.

One group that has routine customer interaction that is not housed within Customer Operations is the PSE&G Gas Delivery organization which, among other things, has responsibility for gas safety (e.g., leak investigations) and appliance services.[4] This organization reports to Jorge Cardenas, Vice President – Gas Delivery, and Mr. Cardenas reports to Ralph LaRossa, President & COO of PSE&G.[5]

[4] Interview with Joe Bassolino, Manager – Business Development (Appliance Services) and Robert Blache, District Manager – Gas Distribution & Appliance Services, on August 19, 2010.
[5] Response to Discovery, OC-1270.

However, most of the focus in this chapter will be on the Customer Operations organization as it is defined by PSE&G. Appliance services, to the extent that it is considered a competitive business segment, will be addressed in our discussion of the company's compliance with EDECA.

Customer Service Functions

As organized by PSE&G, the principal Customer Operations departments in July 2010 were:[6]

- Billing & Revenue Operations Department – This department has responsibility for the company's revenue cycle processes which include billing, credit and collection, revenue integrity, payment assistance outreach, and payment processing. In doing so, this department strives to minimize bad debts and manage the overall health of the utility's receivables (180 full-time equivalents (FTEs)).

- Field Operations Department – This department is predominately made up of union members who are responsible for, among other things, reading customer meters, receiving payments tendered by customers, and disconnecting service at the meter in certain circumstances (606 total FTEs).[7]

- Utility Marketing Department – This department has overall responsibility for customer campaigns, demand side management programs and operations, customer/market research and analysis, customer regulatory strategy, and innovative customer-focused pilot programs (e.g., myPower). At the time the organization chart was produced, the head of this department, Dominick Facchini, had also temporarily assumed responsibilities associated with customer service centers and the aforementioned Billing & Revenue Operations Department (184 FTEs, excluding Billing & Revenue Operations).

- Customer Contact Department – General inquiry and inbound collections call centers located in Cranford and Bordentown, NJ (561 FTEs).

- Large Customer Support & Area Development Department – In September 2010, this department was responsible for, among other things, the formation and implementation of strategies to maintain and increase customer satisfaction among large and moderate-sized industrial and commercial customers (including governmental customers), developing and directing domestic and international business attraction efforts, and coordinating business advocacy and economic development efforts. The Area Development Department was eliminated subsequently (October, 2010).[8]

- Customer Contact & Technology Department – The head of this department, Daniel Eichhorn, was previously Director – iPower. iPower is the term used by the company to refer to its new

[6] Derived from responses to Discovery, OC-73 and OC-1270. Note that departmental names were derived from the job title of the leader except in the case of Daniel Eichhorn, Director – Customer Contact & Technology. His title listed in response to OC-1270 was for a position he had previously held (Director- iPower).
[7] Interview with Joe Bassolino, Manager – Business Development (Appliance Services) and Robert Blache, District Manager – Gas Distribution & Appliance Services, on August 19, 2010.
[8] Response to Discovery, OC-1213.

customer information system as well as several other systems that were implemented at the same time (2007-2009 timeframe). The iPower project management organization was disbanded in October, 2009.[9] The group which now reports to Mr. Eichhorn has documented responsibility for measurement system operations and meter repair.

- Corporate Branding & Advertising Department – This department's far-ranging responsibilities include generating marketplace awareness, designing and producing utility bill inserts, and managing the annual meeting (5 FTEs).

- Business Process Standards & Analysis Department – This department is responsible for leading the process improvement efforts and monitoring the standards and procedures of the Customer Operations organization. It is also responsible for developing and implementing initiatives to close balanced scorecard gaps and for analyzing and developing performance forecasts and explanations of results (11 FTEs).

Systems

Introduction - The primary information system supporting customer service operations is iPower according to the company.[10] However, iPower is not synonymous with PSE&G's customer information system. PSEG's newly-adopted customer information system, SAP's Customer Care System, is only one component of iPower. The iPower project also includes:[11]

- an upgraded interactive voice response unit,
- a new self-service website which permits customers to view and pay their bill on-line, sign up for paperless billing, start or transfer service, schedule service appointments, enroll in the Equal Payment Program, purchase service contracts, report power outages, etc.,
- new hand-held devices for field collectors,
- mobile computers for electric meter technicians,
- the replacement of PSE&G's Gas Service Information Management System,
- the upgrade of the company's Meter Data Repository, and
- the replacement of the information storage and report system with SAP's Business Warehouse reporting module.

However, due to the magnitude of the customer information system replacement, most of the focus of our discussion is on this aspect of the project. Because the iPower project was a major undertaking during the audit period and the company received criticism from numerous parties regarding its roll-out of the underlying systems, further review is warranted.

iPower Project Initiation - The genesis of the iPower project was, in some ways, the byproduct of the unraveling of the proposed PSEG-Exelon merger in late 2006. When PSEG and Exelon were investigating how they would combine the two companies, one joint decision made was to adopt Exelon's customer

[9] Response to Discovery, OC-1272.
[10] Response to Discovery, OC-430.
[11] Responses to Discovery, OC-346 and OC-598.

information system for the combined companies and thereby replace the 28-year old legacy system used by PSEG.[12] **[Begin Confidential]**

[End Confidential][13]

After initial approval, the company solicited separate competitive bids for the platform, the system integration design phase, and the system integration realization phase. Only two platform companies were solicited for bids, and PSE&G selected the lowest bid of the two, SAP America. According to the company, the bids requested five-year forecasted pricing inclusive of all software licensing, maintenance, and support costs.

For the two phases of system integration, the company solicited bids from a more extensive list of vendors. Eight vendors were contacted to bid on the design phase and six for the realization phase with three of these companies solicited for both phases. The request for the design phase work was structured to obtain not-to-exceed time and materials pricing to complete the scope of work. The solicitation for bids on the realization phase was for fixed price bids based on a proposed resource plan required to complete the scope of work. Quintel was ultimately selected to perform both phases of the system integration even though its bids were not initially the lowest in either phase. With respect to the design phase, the lower bids from Accenture and Tata were rejected for a variety of reasons including, but not limited to, lack of team experience, unrealistic timelines, a history of previous project overruns, over-dependence on sub-contractors, and firm reputation. Quintel was awarded the system integration realization phase work after a secondary solicitation was issued and one competing bid was rejected because of concerns about experience and ability to complete the project on a timely basis within budget and another bid was rejected because of pricing.[14]

<u>*iPower Implementation*</u> – To oversee the implementation of iPower, the company created an iPower Project Management Organization. This organization consisted of a dedicated team of employees from Information Technology, Gas Delivery, Electric Delivery, and Customer Operations as well as professionals from Quintel who worked from a common location at offices at 744 Broad Street in Newark, NJ. The Program Manager of this team was Dave Daly through January 2008 and then Daniel

[12] Interview with Dave Daly, Vice President - Asset Management & Centralized Services, on September 2, 2010.
[13] Response to Discovery, OC-926 (Restricted).
[14] Response to Discovery, OC-1273. Although requested, we were never provided a copy of these competitive bids. According to the company, "the responses to the various RFP's and RFI's for the new Customer Information System and the resulting contracts between PSE&G and winning bidders are subject to Confidentiality and Non-Disclosure Agreements. PSE&G is in the process of seeking authorization from each of the vendors who bid to disclose their proposals, which will be provided upon receipt of their authorization" (response to Discovery, OC-598 dated March 12, 2010).

Eichhorn.[15] The number of people assigned to the project team ranged from 48 employees and approximately 40 Quintel associates in 2007 to 82 employees and approximately 67 Quintel consultants in 2009.[16]

Ten key milestones were established for the two-year planned roll-out of the project, including a 9-month period of post-production support and performance metric evaluation.[17] In late 2008 (approximately 14 months after formal approval), the company decided to postpone the go-live date from January 5, 2009 to February 3, 2009 citing a readiness checklist which indicated that additional time was needed to ensure system functionality and performance were on target. When it became apparent that this new deadline was not achievable, the go-live date was delayed again.[18] The new customer information system was placed into service on April 1, 2009.[19] **[Begin Confidential]**

[End Confidential][20]

When converting customer information systems, the company decided not to run the new system parallel with the old system as a way of assessing the reliability of the new system. Management pointed to any of a number of reasons for its decision, including:[21]

- Quintel, the system integrator, recommended against the practice due to the significant costs and complexities that it would add,
- Approximately 100 temporary interfaces would have had to been built, tested, and implemented,
- The project schedule would have needed to be extended by six to eight months,
- The additional work and longer schedule would have added $30 - $40 million to the project cost, and
- Maintaining two production systems would have doubled the work for many associates and increased the challenges associated with change management issues.

Despite the delay in "going live", costs incurred on the iPower project totaled $155.1 million, which was $5.7 million less than the $160.8 million originally approved.[22] The $155.1 million included $119.1 million that the company capitalized and ultimately recorded to Property, Plant and Equipment and $36.0 million that was deferred in a regulatory asset account pending potential recovery in rates. The

[15] Response to Discovery, OC-927 and informal communications with company dated April 5, 2011.
[16] Response to Discovery, OC-1272.
[17] Response to Discovery, OC-83.
[18] Response to Discovery, OC-614 (presentations to the BPU dated December 10, 2008 and March 2, 2009).
[19] Response to Discovery, OC-598.
[20] Response to Discovery, OC-926 (p. 15 of 42) (Restricted).
[21] Response to Discovery, OC-1369.
[22] Response to Discovery, OC-1276.

latter amount consisted largely of training costs.[23] In the BPU Decision and Order Approving Stipulation and Adopting Initial Decision (Docket No. GR09050422), the company and other parties agreed and the Board approved a plan whereby PSE&G would be permitted to recover only $23.52 million of the deferred costs over a four-year period. This amount represented the deferred costs incurred during the test year.[24] The remaining deferred costs were written off by the company in June 2010 to Electric Other Deductions (Account No. 426.5.1) and Gas Other Deductions (Account No. 426.5.2).[25]

To understand how it is possible for the company to miss its self-imposed deadline while at the same time coming in under budget, it should be pointed out that the company built into its original cost estimates nearly $32 million for risk and contingencies.[26] In addition to this "cushion", the company was successful in prodding its two primary vendors, SAP and Quintel, to remediate underperformance by providing services at no extra charge (SAP) or providing services for an amount that was $5 million less than originally anticipated (Quintel).[27]

To address difficulties experienced during the roll-out of the new system, the company took a number of corrective actions. Four cross-functional teams were established to resolve iPower open performance gaps. These four groups were as follows:[28]

- Root Cause Analysis Team – systematic analysis and root cause identification; engaged experts from SAP, Quintel, and EDS
- Change Management Team – quality assurance and risk management on recommended solutions
- Implementation Team – testing and management of solutions into production
- Monitoring Team – enhanced measurement of performance and impact of solutions

Members of these teams were largely, if not completely, made up of information technology employees of the company supplemented with outside consultants.[29] **[Begin Confidential]**

[23] Response to Discovery, OC-928. Amounts capitalized included $3.0 of AFUDC.
[24] Response to Discovery, OC-1054 (pp. 3-4 of the Decision and Order).
[25] Response to Discovery, OC-1279. Given that the company represented that deferred costs related to iPower totaled $35.99 million and deferred costs permitted to be recovered in rates totaled $23.52 million, the amount to be written off should have been $12.47 million (35.99 -23.52). However, the company reported that it wrote off $14.11 million instead. Given the timing of this discovery, we were unable to determine the reason(s) for the discrepancy between these two amounts.
[26] Response to Discovery, OC-1276.
[27] Response to Discovery, OC-1286.
[28] Audit Committee meeting minutes dated July 21, 2009. **[Begin Confidential]** **[End Confidential]**
[29] Response to Discovery, OC-607.

[End Confidential][30]

Perceptions of the company's performance in implementing iPower were wide-ranging. Management directly responsible for the oversight of the project believed that they had performed admirably. It was pointed out more than once that the cut-over to the new customer information system was achieved as originally scheduled, and compared to similar conversions, the iPower project implementation was viewed as highly successful.[31] As noted above, the project came in under budget. **[Begin Confidential]**

[End Confidential][32]

On the other hand, other parties viewed the success of the iPower project implementation less favorably. Informal discussions with BPU staff indicated an overall concern with the timeliness of the roll-out of the new customer information system as well as with the responsiveness to customer concerns post-implementation. Local news media noted company customer billing system shortcomings in two stories released in October and December, 2009.[33] Executive management described the project implementation as "average", "fair", or "not up to standard".[34] Opinions of members of the PSEG Board of Directors, however, were generally more pointed. One agreed with company management and characterized the project implementation as "fair", but others labeled the project as a "problem" or an "embarrassment".[35]

The reality of the situation most likely lies in between these disparate views. CS Week and Electric Light and Power Magazine presented PSE&G its annual award in 2010 for Best CIS Implementation for a Large Utility over 11 other nominees.[36] **[Begin Confidential]**

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[30] Response to Discovery, OC-604 (Restricted On-Site Only).

[31] Responses to Discovery, OC-83, OC-598 and interview with Dave Daly, Vice President – Asset Management & Centralized Services, on September 2, 2010.

[32] Response to Discovery, OC-1368 (Restricted).

[33] "PSE&G Can't Get Billing Right", HeraldNews, October 13, 2009 and "PSE&G Rate Hike Request Draws Heat; Hearing in Hackensack", NorthJersey.com, December 11, 2009.

[34] Interviews with Caroline Dorsa, Executive Vice President & CFO, on October 19, 2010 and Ralph LaRossa, President & COO – PSE&G, on October 22, 2010.

[35] Interviews with various members of the PSEG Board of Directors.

[36] Response to Discovery, OC-1282.

[End Confidential][37]

Management reported that it had adopted an aggressive schedule involving a complex system and largely met its goals.[38]

On the other hand, while the system transition compared favorably to those of other companies, most management-identified performance measures for the Call Center, Billing, and Collections waned during the system transition and only gradually returned to pre-installation levels over the ensuing 12+ months as demonstrated in the following table:

[Begin Confidential]

Table 22-2 – Key Operational Metrics

Key Operational Metrics							
Description	Steady State	April 2009	July 2009	October 2009	January 2010	April 2010	May 2010
[redacted]							

[End Confidential]

A temporary "dip" in productivity was anticipated by management. However, its publicly stated objective was to eliminate it.[39] The improbability of attaining this goal may have ultimately played a role in the diverse opinions regarding the success of the project.

[37] Response to Discovery, OC-1143 ("iPower Update Report to the PSEG Board of Directors" dated June 15, 2010, p. 8) (Restricted On-Site Only).

[38] Interview with Dave Daly, Vice President – Asset Management & Centralized Services, on September 2, 2010.

iPower Project Aftermath – In implementing iPower, the company accomplished the following:[40]

[Begin Confidential]

[End Confidential]

The key lessons learned from this process were summarized in a presentation made by management to the PSEG Board of Directors in June, 2010. They are as follows:[41]

[Begin Confidential]

[39] Response to Discovery, OC-614 ("SAP CCS – New Customer System Update" dated May 12, 2008, p. 14).

[40] Response to Discovery, OC-1143 (Restricted On-Site Only).

[41] Response to Discovery, OC-1143 ("iPower Update Report to the PSEG Board of Directors" dated June 15, 2010, pp. 11-14) (Restricted On-Site Only).

[End Confidential]

Other Systems – Another productivity enhancement resulting from the iPower project was the introduction of global positioning system (GPS) technology to the service technician workforce. Among other things, GPS permits the company to locate the nearest technician when immediate assistance is needed, to conduct timesheet audits by comparing submitted time to "breadcrumb trails", to provide directions when technicians are operating outside of normal work districts, to optimize routes, and to monitor productive and down time.[42]

One technology that PSE&G has not adopted to date is an automated (advanced) metering infrastructure (AMI). While the advantages of AMI are numerous (ability to read meters remotely, to provide demand response solutions, to manage outages, etc.), deployment is complicated by the impact it would have on a union meter-reading workforce and the perception of some that the technology does not benefit all customers, especially those at lower income levels. As recently as 2008, the company was pursuing a long-term strategy of system-wide implementation of AMI. However, in November of that year, PSE&G informed the New Jersey BPU that it was suspending a pilot program which was intended to validate and compare different vendor solutions because of the then current financial climate. The suspension of this pilot effectively suspended the long-term system-wide implementation of the technology.[43] **[Begin Confidential]**

[End Confidential][44]

Performance Metrics

As mentioned elsewhere in this report, performance measurement of service company operations through the use of formal balanced scorecards began in 2008, approximately five years after they were implemented for utility operations. Customer Operations, as a part of utility operations, has had an overall balanced scorecard for several years as well as scorecards for some of its underlying sub-processes.[45] The balanced scorecard for the entire Customer Operations organization for 2008 and 2009 is as follows (as noted in elsewhere in this report, the major groupings of individual scorecard metrics changed between 2008 and 2009):

[42] Response to Discovery, OC-1235.
[43] Response to Discovery, OC-1274.
[44] Response to Discovery, OC-1233 (Restricted).
[45] Response to Discovery, OC-1220.

Table 22-3 – Customer Operations, Balanced Scorecard Results, 2008

Customer Operations Balanced Scorecard Results 2008			
Description	Target	Actual	Performance
People:			
OSHA Recordable Incidence Rate	1.60	1.22	+
OSHA Days Away Rate (Severity)	4.35	1.61	+
Motor Vehicle Accident Rate	3.29	3.58	-
Total Availability	96.7%	95.8%	-
Overtime	4.2%	6.1%	-
Employee Engagement Index	74%	72%	-
Total Staffing Levels	1,766	1,707	+
Wellness Participation Index	60%	50.4%	-
Employee Development Training – MAST	90.0%	96.1%	+
Employee Technical Training – BU	100%	107.1%	+
Employee Enhancement Training – BU	100%	96.0%	-
Customer Care:			
Moment of Truth Survey – CO	8.6	8.6	+
Perception Survey (Residential/Small Business)	75	75	+
Perception Survey (Large Business)	76	76	+
Constituent Satisfaction Index	7.6	7.2	-
New Business Construction Survey	7.9	8.3	+
Regulatory Inquiries – Non-Collections	1,487	921	+
Regulatory Inquiries – Collection	3,916	4,486	-
First Contract Resolution – Inquiry	86.0%	87.0%	+
Operations:			
General Inquiry Service Level (30 sec.)	75.0%	75.1%	+
Abandonment Rate – Inbound Collections	16.0%	10.9%	+
Total Actual Reads	89.5%	89.9%	+
Meters Not Read > 7 months (k)	54.0	65.1	-
MR Errors / 10,000 Reads	4.2	3.9	+
Accts Converted to Bills & Printed	98.6%	98.8%	+
Billing Exception Time	4.3	3.6	+
Payments Deposited within 1 Business Day	94.0%	94.9%	+
Total Appliance Service revenue ($M)	131.0	129.8	-
LCS Outdoor Lighting Sales ($M)	4.0	5.3	+
Client Value Assessment	8.4	8.3	-
Financial:			
Total CapEx ($M)	26.8	10.6	+
iPower – Capital ($M)	75.3	53.1	+
iPower – 2008 Realization Costs ($M)	90.7	66.4	+
Accountability O&M ($M)	164.9	161.6	+
Unbilled Revenue Recovery ($M)	28.8	32.2	+
Net Write-Offs ($/$100 billed revenue)	0.84	0.84	+
Days Sales Outstanding	35.9	35.4	+
Aged Receivables > 90 Days	14.1%	14.5%	-

Sources: Responses to Discovery, OC-86 and OC-1221.
+ = Met or exceeded targeted performance
- = Failed to achieve targeted performance

Table 22-4 – Customer Operations, Balanced Scorecard Results, 2009

Customer Operations Balanced Scorecard Results 2009			
Description	Target	Actual	Performance
People:			
OSHA Recordable Incidence Rate	1.15	1.10	+
OSHA Days Away Rate (Severity)	1.61	19.31	-
Motor Vehicle Accident Rate	3.21	5.24	-
Availability – Illness	97.3%	95.6%	-
Staffing Levels – Permanent	1,489	1,512	-
Overtime	2.6%	11.9%	-
Employee Technical Training – BU	100%	110.0%	+
Employee Development – MAST	95.0%	98.4%	+
Corporate Culture for Ethics and Compliance	62%	65%	+
Safe:			
Percent of Actual Meters Read	90.1%	88.5%	-
Meters Not Read > 7 Months (k)	55.2	Unknown	N.A.
MR Errors / 10,000 Reads	3.9	3.9	+
General Inquiry Service Level (30 secs.) (A)	51.0%	61.7%	+
Abandonment Rate – Inbound Collections	10.9%	16.7%	-
First Contact Resolution	Tracking	Unknown	N.A.
Accounts Converted to Bills and Printed	98.8%	Unknown	N.A.
Billing Exception Time	3.6	Unknown	N.A.
Payments Deposited within 1 Business Day	96.5%	99.0%	+
Participation in Auto-Pay	126,994	145,038	+
Cashier Errors	3.7	Unknown	N.A.
BPU Inquiry Rate – Collection	1.25	1.78	-
BPU Inquiries – Non-Collection	1,038	2,413	-
Perception Survey (Residential / Small Business)	76	74	-
Perception Survey (Large Business)	77	76	-
Moment of Truth Survey	8.7	8.2	-
New Business Construction Survey – CO	8.4	8.0	-
Client Value Assessment	8.4	8.9	+
Constituent Satisfaction Index	7.2	7.6	+
SOX Test Failure	2	5	-
Economic:			
CapEx ($M)	5.8	2.1	+
iPower CapEx ($M)	11.1	31.0	-
Accountability O&M ($M)	175.5	178.0	-
Net Write-Off ($/$100 billed)	0.82	1.24	-
Days Sales Outstanding	34.5	37.1	-
Aged Receivables > 90 Days	14.5%	20.0%	-
Notice Dollars Collected on RNP	70.1%	Unknown	N.A.
Dollars Treated by Field Collections	251.5	Unknown	N.A.
Unbilled Revenue Recovery ($M)	34.1	25.3	-
Delinquent Accounts Covered by Deposit	23.0%	17.4%	-
LCS Outdoor Lighting Sales ($M)	3.6	4.2	+
Contract Revenue ($M)	85.3	88.5	+
AWH Revenue ($M)	15.5	14.8	-
HVAC Revenue ($M)	29.1	25.2	-
Payment Assistance - # of Accounts	267,185	293,677	+

Customer Operations Balanced Scorecard Results 2009			
Description	Target	Actual	Performance
Payment Assistance – Dollars ($M)	167.8	205.1	+
Capital Projects' Results	95.0%	89.6%	-
Green:			
Web Transactions	3.0%	22.1%	+
Paperless Billing	2.5%	2.0%	-
Solar Loan Program Applications (MW)	19.0	20.1	+
Cost per Tier 1 Audit (Whole House Efficiency Sub-Program)	184	154	+
Carbon Abatement Committed Contracts ($M) (B)	12.0	13.7	+
Fleet MPG	8.9	8.9	+
Non-Hazardous Waste	69.5%	72.1%	+

Sources: Responses to Discovery, OC-86 and OC-1221.
+ = Met or exceeded targeted performance
- = Failed to achieve targeted performance
(A) Excluding first 10 days after the iPower "go-live".
(B) For warehouses and hospitals.
Note: In some cases, actual amounts are "unknown" because reports are under development.

When benchmarking data is available, balanced scorecard targets are set to achieve top quartile operational metrics and top decile safety metrics.[46] Otherwise, the company strives to achieve year-over-year improvement.[47]

In general, the Customer Operations organization was successful in adopting targets in 2009 that promoted continuous improvement. Compared to other significant service company organizations such as Financial Services (headed by Caroline Dorsa, Executive Vice President & CFO), Customer Operations had nearly twice the number of balanced scorecard performance metrics for the overall organization (53 vs. 28 in 2009).[48] Given the similar complexities of both organizations with multiple sub-processes reporting to one common executive, it would seem that the difference in the number of performance metrics tracked at a consolidated level between the two organizations was most likely due to management preference. One concern with the approach adopted by Customer Operations is that reporting and tracking so many different metrics at the consolidated level may render the failure of any one metric inconsequential.

A significant amount of Customer Operations' under-performance to expectations in 2009 can most likely be traced to the implementation of the new customer information system in April, 2009. As noted in our discussion of the iPower project implementation, steady state performance was not achieved, in many cases, until mid-2010.

[46] Response to Discovery, OC-1239.
[47] Interviews with Ralph Izzo, Chairman, President and CEO, on December 7, 2010 and Bill Nash, former Manager – Business Process, Standards & Analysis, on August 20, 2010.
[48] Derived from responses to Discovery, OC-1221 and OC-1271.

Benchmarking

When asked for post-2007 benchmarking data concerning the Customer Operations organization, we were provided two sources of information. They are summarized below:[49]

[Begin Confidential]

[49] Response to Discovery, OC-57 (Restricted On-Site Only). Comparisons made are to those who responded. In some cases, a survey participant may not have responded to every request for data.

[End Confidential]

PSE&G 2010 Peer Panel Benchmarking Study[50] - Participation increased to twelve companies in 2010. The study, which was based on 2009 data showed:

- For the first time since the peer panel was convened, PSE&G was not the utility with the most regulatory complaints. However, although one other company had more complaints, PSE&G's total complaints increased 35 percent over the previous year.

- PSE&G's relative ranking and its overall meter read error rate stayed constant with the previous year's results.

- PSE&G read 88.50% of all meters. This placed the company last among the 9 respondents to the survey. This relative poor performance may be due in part to the company's heavy reliance on manual meter reads compared to other companies that have employed a greater degree of mobile drive-by and remote one-way technology.

- PSE&G's relative ranking in General Inquiry statistics were similar to the previous year. PSE&G finished eighth out of ten in average speed of answer, ninth out of ten in average call handle time, and fifth out of six in percentage of call answered within 30 seconds.

- Unlike previous years, PSE&G did not report statistics concerning billing errors.

PSE&G participated in a separate benchmarking study conducted by PA Consulting in each of the three years 2007-2009. Results of these studies included:[51]

[Begin Confidential]

[50] Response to Discovery, OC-1024.
[51] Obtained or derived from response to Discovery, OC-57 (Restricted On-Site Only).
[52] Some participants were geographical segments of a larger company. For example, the Midwest and Southeast segments of one company were treated as two participants.

[53] The term "adjusted customer" refers to situations in which one customer takes both electric and gas service from the same utility. In these situations, the customer is counted twice because they have the potential to have twice the number of interactions with the utility as a customer who only has electric service or a customer who only has gas service. PSE&G believes that measurements incorporating "adjusted customers" are more meaningful (per response to Discovery, OC-57 Supplemental).

Table 22-5 – PA Consulting Benchmarking Survey

PA Consulting Benchmarking Survey (dated September 5, 2008)					
Description	1st Quartile	2nd Quartile	3rd Quartile	4th Quartile	Total
[redacted]					

[End Confidential]

While these various benchmarking studies cover a wide range of topics, some of which were not summarized above, the overall impression they leave is that PSE&G is performing, at best, average when compared to its peers.[54] However, it should be noted that data summarized in the studies above are generally from the previous year (e.g., a 2008 survey uses 2007 data, a 2009 survey uses 2008 data, etc.). As a result, they largely do not reflect the company's conversion to new customer service systems, and they most likely capture some of the inefficiencies realized by the organization during a period of intense transition. When coupled with the inherent disadvantage of operating in a high cost-of-living labor market and in a service territory in which automated metering infrastructure has yet to be implemented, it is easy to understand how the company does not compare favorably to other utilities.

[54] The company actually characterized the quality of customer services as a "consistent underperformer" in a presentation to the BPU Staff in May, 2008 (response to Discovery, OC-614).

Customer Satisfaction[55]

PSE&G Customer Operations incorporated measurements of customer satisfaction into its balanced scorecard in both 2008 and 2009. These measurements included both customer perception and transactional satisfaction.

Customers' perceptions are quantified through an aptly-named Customer Perception Index. This index measures perceptions related to three broad-based topics -- overall satisfaction with the company, how well the company is meeting expectations, and how the company compares to an ideal utility -- involving three distinct segments (residential, small business, and large business). This particular method of measuring satisfaction has been employed by the company since 2005 with 2004 serving as a baseline. The survey takes the form of randomly placed phone calls throughout the year with customers who may or may not have had specific transaction with PSE&G and covers a variety of subjects including reliability of service, power outage restoration and communications, price and value, trust, corporate citizenship and community involvement, telephone service, field service, environmental and energy efficiency efforts, past interaction with employees, and customer communications. The survey is the responsibility of by the Customer Assessment Group which reports to Dominick Facchini, Director – Utility Marketing. Both surveys are conducted by 3rd party vendors who publish the results quarterly.[56]

The Customer Perception Survey benchmarks PSE&G's performance on over 30 measures against the performance of more than 80 utilities. The third quarter 2009 survey showed that PSE&G achieved first quartile results in 26 of 34 residential measures. This appears to have reversed a trend that had shown general year-over-year improvement since 2005, although it is unclear whether the timing of a survey (e.g., third quarter vs. fourth quarter) impacts customer's perceptions to any significant degree.[57] In the third quarter 2009 survey, PSE&G's relative ranking for residential customers was lowest for a measurement concerning the reasonableness of electric rates for the value received (third quartile). Contrast that with PSE&G's performance as perceived by small business customers. In the third quarter of 2009, PSE&G only achieved a first quartile ranking in 4 of 33 small business measures. At the same time, it ranked in the third quartile in 13 of 33 measures, including overall satisfaction. Nine months earlier (at the end of 2008), PSE&G was not ranked in the third quartile of any small business measurement. No large business segment trend data was provided in this 2009 survey.

According to the company, residential and small business customers remain concerned about paying their bills, and those who are concerned about their bills have a lower Customer Perception Index (CPI). These concerns do not necessarily explain the declines in PSE&G's relative ranking with respect to other utilities (i.e., it would be expected that residential and small business customers nationwide would have similar concerns), but they do shed some light on the year-over-year decline in raw CPI data that PSE&G tracks for purposes of its balanced scorecard (see Tables 22-3 and 22-4 above). Key drivers of the

[55] Response to Discovery, OC-88.

[56] Responses to Discovery, OC-88 (p. 306 of 385) and OC-1270 (p. 9 of 116).

[57] Except for third quarter 2008 data, all other trend data presented in the survey was as of year-end. 2006 year-end results showed PSE&G achieved first quartile results in 29 of 33 measurements. At year-end 2007 and in the third quarter of 2008, PSE&G achieved first quartile results in 29 of 34 measures. (response to Discovery, OC-88 (pp. 331 and 332 of 385).

decline in overall small business customer perception included, but were not limited to, concerns about electric rates, billing, energy efficiency assistance, communications, telephone support, and minimizing power interruptions. With that being said, it is likely that the difficulties experienced by the company in rolling out iPower had a negative impact on customer perceptions as measured in this survey. The company said as much when it identified the iPower implementation and the unstable economic environment as "challenges" faced by the company in this survey.

The other primary measurement of customer satisfaction focuses on transactional performance and is captured in Moment of Truth surveys. These surveys are conducted throughout the year with randomly selected customers and cover such topics as call centers, walk-in customer service centers, electric field services, gas distribution field service, appliance service repairs, and appliance service emergencies. For purposes of assessing the Customer Operations organization, the survey results are limited to the first two groups listed -- call centers and walk-in customer service centers. As with the perception surveys, these surveys are conducted by and outside vendor working for the Customer Assessment Group.

With respect to Customer Operations, the most recent quarterly survey provided was that from the second quarter of 2009, the first three months after the conversion to the new customer information system. Residential and small business customers were surveyed for their thoughts on call centers and the walk-in customer service centers. The key findings were as follows:

- Overall satisfaction with the Customer Operations process is significantly lower than 2008 second quarter measurements, 2008 year-to-date measurements, or 2009 first quarter measurements. Customer dissatisfaction involved both call centers and customer service centers.

- Both year-to-date and year-over-year declines in satisfaction with the call center inquiry process involved all aspects of interaction including wait times, first call resolution, satisfaction with company personnel, and satisfaction with the voice recognition unit.

- Customer service center satisfaction was lower on both a year-to-date and quarterly basis due to dissatisfaction with representatives, with first contact resolution, and with perceived wait times.

- From the first quarter of 2009 to the second quarter, customer-reported hold times to the call center for inquiries increased from 3.4 minutes to 5.2 minutes, and total time on a call increased from 5.6 minutes to 6.7 minutes.

- On average for those customers who did not receive first call resolution, it took 2.9 calls to resolve issues raised by both residential and business customers in the first half of 2009. This is consistent with the 2.8 calls measured year-to-date for 2008.

- Approximately one in 10 customers reported that the voice recognition unit routed them to the incorrect person or department in the first half of 2009. Between the first quarter and second quarter of 2009, the number of customers who reported that the voice recognition unit had the appropriate number of prompts decreased from 79% to 65%. In most cases, they felt that there were too many prompts.

- Fewer customers in the first half of 2009 visited walk-in customer service centers to pay their bills (38% vs. 51%). However, between the first quarter of 2009 and the second quarter, the percentage of visitors addressing collection matters increased from 24% to 32%.

- Wait time at customer service centers increased from 11.5 minutes in the first quarter of 2009 to 18.9 minutes in the second quarter. Wait times of 10 to 15 minutes were assumed to meet targeted satisfaction.

- Customer service center satisfaction appears to be tied to how busy a location is. For purposes of the 2009 second quarter survey; Burlington, Jersey City, Newark, Trenton, and West Orange were among the lowest.

Given that the timing of this particular survey coincided with the aftermath of the roll-out of the new customer information system, it is not entirely unexpected that glitches with the system and delays associated with the transition would have negatively impacted customers' experiences with the company. As we have previously noted, the company attempted to respond to these concerns directly by increasing the number of call center employees to alleviate wait times. At the same time, teams were created to identify the causes of system problems and to correct them. While we were not provided Moment of Truth surveys after the second quarter of 2009, we observed that the Customer Operations Moment of Truth survey score as reported in the balanced scorecard metrics had increased slightly from 8.2 in 2009 to 8.3 in July 2010, although it still was below targeted levels of 8.7 and pre-iPower implementation levels noted in 2008 of 8.6.[58]

According to management, the company's action plans to improve performance in the customer satisfaction surveys (both Perception and Moment of Truth) are documented in Perception Working Team Dashboard Reports.[59] A copy of the most recent report dated August 18, 2010 is provided in Attachment 22-1. This report shows that call center telephone service trails targeted levels in four of seven key metrics tracked, and customer service centers are deficient in one of two key metrics tracked.[60]

Meter Reading

PS&EG does not have a system-wide advanced metering infrastructure, so it relies on its 370-member union workforce to perform most of its meter reading. According to the company, out of 3.8 million electric and gas meters, approximately 450,000 are read through automation.[61] **[Begin Confidential]**

[End

[58] Response to Discovery, OC-1271.
[59] Interview with Jane Bergen, Director – Customer Contact, on August 18, 2010.
[60] Response to Discovery, OC-1225 ("Customer Perception Lead Updated" dated August 18, 2010, pp. 5 and 8).
[61] Response to Discovery, OC-84.

Confidential][62] Another portion of meters in any given month cannot be accessed by company personnel because the meters are located inside customer premises.[63] The usage on these meters must be estimated if customers do not provide the necessary information, and bills generated by this process are marked as averaged.[64] The number of meters that are not read in a given month has hovered around 10 to 11 percent in recent years, although this percentage has been as low as 9.2 percent (April 2008) and as high as 20.3 percent (February 2010).[65]

Meter reading statistics for the past four years are summarized in the following table:

Table 22-6 – Meter Reading Statistics

Meter Reading Statistics				
Description	2007	2008	2009	2010
Actual Reads	36,427,068	36,168,175	36,184,254	35,977,421
Customer Reads	167,124	146,043	99,885	112,930
Walk-By Remote	1,247,094	1,417,703	1,580,593	2,003,612
Drive-By Remote	3,389,531	3,585,841	3,646,074	3,698,096
Estimates	5,367,972	5,470,535	5,500,833	5,417,357
Total	46,598,789	46,788,297	47,011,639	47,209,416
Source: Response to Discovery, OC-1483.				

Customer reads decreased in 2009 due to the compressed meter read schedule in preparation for the conversion to the company's new customer information system. Walk-by remote reads are on the increase because of new meter purchases equipped with Itron Remote Modules.[66]

As stated in its electric and gas tariffs, PS&EG reserves the right to discontinue utility service when a meter reading is not obtained for eight consecutive billing periods, and after written notice has been sent to a customer in the fifth and seventh months explaining that a meter reading must be obtained. PSE&G makes a good faith effort to read customer meters, offering to come by in the evening or on Saturday, setting up special appointment times, or accessing private property by using customer-provided keys or combinations. Despite these efforts, some customers receive service even though they do not comply with these policies. Presumably, these customers are paying their estimated bills on a timely basis or are protected under the New Jersey BPU's Winter Termination Program. In 2007, 2008, and 2009, the number of customers who did not comply with the PSE&G's meter reading policy totaled 62,389; 65,096; and 85,770; respectively.[67]

Customers can submit meter readings either on-line or by phone if they have had fewer than twelve consecutive estimates. Readings must be submitted between seven days and one day prior to a

[62] Derived from response to Discovery, OC-608 (Internal Audit Report on PSE&G Metering dated February 25, 2008) (Restricted On-Site Only).
[63] Approximately 54 percent of the company's meters are located inside (response to Discovery, OC-618).
[64] Response to Discovery, OC-612.
[65] Response to Discovery, OC-610 (Update).
[66] Response to Discovery, OC-1483.
[67] Responses to Discovery, OC-612 and OC-84.

scheduled meter reading date.[68] Customer meter reads are accepted indefinitely as long as they are not preceded by twelve consecutive months of estimated reads.[69] Based on a review of the current tariffs of other New Jersey electric and gas utilities, we noted no instances in which the policy with respect to customer meter reads was more restrictive than PSE&G's. Customer reads submitted on-line are subject to validation, just as those reads collected by company meter readers. If a read submitted on-line does not fall within an expected "window" of acceptable readings, the read is rejected and the customer receives a message to verify and re-enter. The same would take place if a customer talks to a representative over the phone and submits an unusual read. However, if the interactive voice response system is used by the customer to submit data, the read is not immediately questioned or rejected. Instead, it is subject to validation when the billing routine is run. If it fails validation at that point, an estimate is used instead, but the customer is not formally notified that his/her read was not used. According to the company, a system enhancement "is under consideration" to add the validation step to the interactive voice recognition process.[70]

At a minimum, a customer should be informed when submitting a meter read using the interactive voice recognition system that his/her submission is subject to validation and may not be used if found to be outside the parameters of reasonableness. However, a much better solution would be to validate the submission immediately just as is done on-line.

Also noteworthy, PSE&G acknowledged a system defect had been identified in August 2010 that relates to customer read submissions. Meter read data sent by customers via the web or the PSE&G interactive voice recognition system that were five days or less before the customer's billing date were being recorded on the account, but the reads were not being used for billing.[71] This corresponds to first-hand reports raised by New Jersey BPU staff.[72] According to the company, a system fix was being designed to correct this situation and was expected to be implemented in late 2010.[73] The company was unable to quantify the number of customers who were affected by this system glitch. The company asserts that the matter was subsequently corrected in November 2010.[74] However, we did not independently verify that a system-wide correction had been made.

Meters are tested in accordance with prior BPU orders and allowed tolerance is +/- 2 percent. Testing programs approved by the BPU in previous orders include selective sample programs, year-in-service tests based on meter type and size, and differential field testing for rotary-type meters.[75] When meters are found to be outside of acceptable tolerances, PSE&G follows New Jersey law which states that

[68] Per review of PSE&G's website.
[69] Response to Discovery, OC-1498. However, this policy is under review for possible change.
[70] Responses to Discovery, OC-611 and OC-1216.
[71] Response to Discovery, OC-1216.
[72] In addition to ignored customer meter read data, New Jersey BPU staff also reported continuing first-hand accounts of other issues associated with PSE&G's meter reading activities. Time constraints prevented us from verifying these reports or determining the extent of these matters.
[73] Response to Discovery, OC-1216.
[74] Response to Discovery, OC-1485.
[75] Response to Discovery, OC-84.

customers are given credit for half of the time the meter was in service for over-billings to original customers.[76] For under-billed readings, commercial and industrial customers are billed for the correction, and residential customers are not billed.[77]

Call Centers

PSE&G operates three call centers – two in Cranford, NJ (Northern) and one in Bordentown, NJ (Southern). One call center in Cranford handles the new business. The other call center in Cranford handles both general inquiries and inbound collections. General Inquiry is operated 24 hours per day and 7 days per week while Inbound Collections operates 5 days per week during normal business hours. The general inquiry call center in Cranford and Bordentown operates as one virtual site. The Bordentown site also has a new business call center.[78]

The call centers were staffed with a predominately union workforce at the following levels:

Table 22-7 – Call Center Force Levels

Call Center Force Levels				
Description	December 31, 2007	December 31, 2008	December 31, 2009	July 31, 2010
General Inquiry:				
Cranford	246	307	337	315
Bordentown	57	62	65	62
Total	303	369	402	377
Inbound Collections:				
Cranford	87	104	110	98
Total Call Center:				
Cranford	333	411	447	413
Bordentown	57	62	65	62
Total	390	473	512	475
Source: Response to Discovery, OC-1215.				

The workforce levels in the table above reflect a decision to add twenty positions to Inbound Collections in late 2007 and early 2008 to improve service levels as well as the ramp-up in General Inquiry needed for the transition to and stabilization of the new customer information system that occurred in 2009.[79] In 2010, as the need for customer service representatives diminished, the workforce levels dropped through natural attrition.[80] PSE&G does not use contractors to staff its call centers. Outsourcing of

[76] For customers who are not the original customer, credit is given for the entire time up to half the time the meter was in service (see response to Discovery, OC-91).
[77] Response to Discovery, OC-91 (pursuant to New Jersey Administrative Code 14:3-4.6).
[78] Response to Discovery, OC-1214.
[79] According to an newspaper article in the Herald News (dated October 13, 2009), the company hired 30 new CSRs in July 2010, intended to hire an additional 50 CSRs (at the time of the article), and would redeploy between 25 and 35 employees from other divisions of the company.
[80] Response to Discovery, OC-1215.

some call center operations has been considered in the past, but it has never gotten beyond preliminary discussions. According to management, the BPU has been consulted when these deliberations have taken place in the past.[81]

One reason the company has opted to operate from two different locations is to minimize the possibility that one event can render all call center functionality inoperable (natural disaster, black-out, etc). A second benefit is that the Bordentown office is located in an area of the state that is viewed by some employees as more desirable, which should aid in employee retention.[82]

Call center employees primarily handle inbound calls. Occasionally, these employees will make outbound calls to set up appointments and check on power outage resolution. The call centers do not make marketing calls. A third party, Varolii, has been retained by PSE&G to make automated outbound reminder phone calls. Inbound overflow calls to the PSE&G call centers are handled by AT&T using a voice response unit. The call centers do not handle any calls for PSE&G affiliates, such as PSEG Power.[83]

Customer service representatives (CSRs) are trained to handle all types of calls. However, calls are routed to CSRs based on their experience and proven ability to successfully resolve similar matters. For instance, the most experienced CSRs are given the responsibility of handling small business billing matters as these tend to be the most complex. One exception is that calls from large business customers can be immediately routed to the large business center.[84]

PSE&G's call centers support Spanish speaking customers and have the ability to service other languages either directly (such as Portuguese and Italian) or through Language Line, a third party that provides translation services.[85]

Customers who call into the company are routed to CSRs by an interactive voice recognition (IVR) system which was upgraded with the implementation of iPower. In mid-2010, menu options of the new IVR included, but not limited to:

- Gas Leak / Power Failure / Life-Threatening Conditions
- Billing
- Account Information
- Make a Payment
- Repairs
- Moving
- Something Else

[81] Interview with Jane Bergen, Director – Customer Contact, on August 18, 2010.
[82] Interview with Jane Bergen, Director – Customer Contact, on August 18, 2010.

[83] Response to Discovery, OC-1214 and interview with Jane Bergen, Director – Customer Contact, on August 18, 2010.
[84] Interview with Jane Bergen, Director – Customer Contact, on August 18, 2010.
[85] Language Line is also used by English speaking CSRs to provide Spanish translation services when the need arises (see response to Discovery, OC-1214).

- Appliance Protection Plan
- Street Light
- Report a Meter Reading
- Hear Next Meter Read Date
- Previous Menu

Calls reporting gas leaks, other emergencies, or no power receive priority treatment and are moved to the front of call queues. Among the other options available to customers through the IVR, bill payment is a new feature of the upgraded system.

As noted previously, the call centers' recent performance has not met customer expectations or other peer companies' achievements. 2009 below-par performance can largely be attributed to the growing pains associated with undertaking a massive computer system conversion. More recent under-performance is more concerning. PSE&G should take the necessary steps to address these areas so that it can achieve at a minimum the top quartile standards that it strives to meet in all areas of its operations.

Billing, Payment Processing, and Credit & Collections

While the vast majority of customers receive mailed copies of their bills, beginning with the roll-out of the new customer information system and associated website enhancements, customers for the first time have the option of receiving electronic bills. In mid-2010, 3.6 percent of customers had opted to receive electronic bills. This number was expected to increase to 8 percent by the end of the year.[86]

According to management, there is approximately an 80 percent overlap in customers who receive both electric and gas service from PSE&G. In the vast majority of cases, these customers are billed for both services on the same bill. BPU regulations allow customers to receive separate bills if they so choose, but this is rarely requested.[87]

In late 2009, PSE&G received criticism in the local media for billing errors related to the implementation of the new customer information system. While not synonymous with billing errors, according to management, the open volume of "billing exceptions" has decreased from pre-iPower levels of 16,000 – 20,000 to 8,000 in August, 2010 after having briefly escalated to 50,000 at the time of system implementation.[88]

PSE&G has sixteen customer service centers located throughout its service territory. These sites are open during normal business hours and offer customers the opportunity to pay bills, arrange for service,

[86] Interview with Vic Viscomi, Former Director – Billing and Revenue Operations, and Mike Kelly, Manager – Operations: Billing, on August 18, 2010.
[87] Interview with Vic Viscomi, Former Director – Billing and Revenue Operations, and Mike Kelly, Manager – Operations: Billing, on August 18, 2010.
[88] Responses to Discovery, OC-1484 and OC-1499 and informal e-mail correspondence with company personnel dated June 3, 2011.

learn about programs available to them, and receive information on energy conservation among other things. PSE&G also accepts payments from customers at Western Union sites.[89]

Besides in-person payments at customer service centers and Western Union, customers can pay by phone and through the company's website. PSE&G accepts payment in cash (at customer service centers and Western Union locations only), by customer check, money order, one-time or recurring electronic funds transfers, or credit card (one-time only). Unlike other forms of payment, credit card payments incur a $4.95 per transaction fee, which represents a pass-through cost according to company representatives.[90] Previously, some check payments had also incurred a fee, but this was eliminated when servicing was brought in-house from JP Morgan.[91]

PSE&G also offers an Equal Payment Plan to customers who are current on their account. This plan allows customers the option of spreading their annual energy costs equally to each month, thus avoiding the spikes in invoiced usage that would otherwise occur during a typical year. Registering for the plan commits the customer to an equal payment for both electricity and gas when both services are offered. Under the plan, a true-up occurs once a year to balance the amount paid to the amount that is owed based on the energy used.[92]

For customers who need assistance in paying their energy bills, CSRs are trained to notify customers of a number of programs for which they may be eligible, including:

- Temporary Relief for Utility Expenses (TRUE) Grant
- Low Income Home Energy Assistance Program (LIHEAP)
- NJ Universal Service Fund (USF)
- NJ Lifeline Credit Program
- NJ SHARES

In addition to these programs, PSE&G also offers Deferred Payment Arrangements (DPAs) to customers who are having difficulty paying their bills. Minimum down payments in arrangements with residential customers are dependent on PSE&G's past experiences with the customer. Generally speaking, if a customer has not broken a DPA within the past twelve months, the minimum down payment is an amount up to 25 percent of the total outstanding balance. If a customer is not shut off but has broken one or more DPAs within the past twelve months, the minimum down payment is an amount no less than 75 percent of the total outstanding balance. Finally, if a customer is shut-off for non-payment and has broken a DPA within the past twelve months, the minimum payment is 100 percent of the total outstanding balance to restore service. The duration of a residential customer's DPA is more subjective

[89] Interview with Vic Viscomi, Former Director – Billing and Revenue Operations, and Mike Kelly, Manager – Operations: Billing, on August 18, 2010.

[90] Obtained from company's website and from interview with Vic Viscomi, Former Director – Billing and Revenue Operations, and Mike Kelly, Manager – Operations: Billing, on August 18, 2010.

[91] Response to Discovery, OC-1214.

[92] Obtained from company's website and from interview with Vic Viscomi, Former Director – Billing and Revenue Operations, and Mike Kelly, Manager – Operations: Billing, on August 18, 2010.

and is a function of amount owed, prior payment history, and sources and timing of income. In the case of a commercial account with residential end use (e.g., apartment building), one DPA can be granted in a rolling 12-month period. The minimum down payment is 50 percent of the total outstanding balance and the remainder must be paid over a 3-month period.[93] According to management, if a customer offers an acceptable down payment, he/she cannot be terminated if no DPA has recently been broken.[94]

The extent to which customers have entered into DPAs is summarized in the following table:

Table 22-8 - SE&G Deferred Payment Arrangements

SE&G Deferred Payment Arrangements (DPAs)			
Description	December 31, 2007	December 31, 2008	October 31, 2009
Number of DPAs	20,103	24,431	38,635
Value of DPAs	$11,200,000	$14,000,000	$19,300,000
Source: Response to Discovery, OC-90.			

The increase in the number and amount of DPAs is most likely due to the general downturn in the economy.

Customers who are delinquent in paying for their service and who do not make alternative arrangements to correct the situation are subject to cancellation.[95] Different steps are taken by the company depending on the type of customer involved. For residential customers, the following dunning process is followed:[96]

- Reminder Message (Level 10): delinquent amount between $30.00 and $59.99 – reminder on invoice – Creditworthiness Score (CRW) less than 109 – CRW increases by 10 points,
- Reminder Message (Level 20): delinquent amount greater than $59.99 – reminder on invoice – CRW less than 109 0 CRW increases by 10 points,
- Soft Disconnect Notice (Level 21): delinquent amount greater than $60.00 – CRW between 109 and 283 – disconnect notice on invoice – CRW increases by 15 points,
- Hard Disconnect Notice (Level 22): delinquent amount greater than $60.00 – CRW greater than 283 – disconnect notice on invoice – CRW increases by 20 points,
- Call Campaign (Level 30): delinquent amount greater than $60.00 – eight days after Levels 21 or 22 – CRW does not increase, and

[93] Response to Discovery, OC-90.
[94] Interview with Vic Viscomi, Former Director – Billing and Revenue Operations, and Mike Kelly, Manager – Operations: Billing, on August 18, 2010.
[95] Subject to the rules of the BPU which protects specific categories of customers from losing their electric or gas service during the period from November 15 to March 15 (Winter Termination Program).
[96] Response to Discovery, OC-1230.

- Field Disconnect Notification Created (Level 40): delinquent amount greater than $199.99 – eight days after Level 30 – CRW greater than 499 – CRW by 25 points.

The dunning process for non-residential customers is more accelerated. PSE&G skips sending reminder notices and soft disconnect notices and immediately begins with sending a hard disconnect notice.

Accounts that the company is unable to collect are eventually written off. Accounts which have been written off and which have an outstanding balance of between $50 and $14,999 are sent to outside collection agencies for recovery. PSE&G uses four different collection agencies – Alliance One, ER Solutions, CBCS National, and NCO Group, Inc. Recent experience shows that these collection agencies generally recover less than 6 percent of all accounts assigned to them.[97]

PSE&G also has sold uncollectible receivables to third parties in the past to offset some of its write-offs. In 2008, it sold $63,450,404 of receivables for $1,586,260 (equates to $0.025 per dollar) to Asset Acceptance. Approximately two years later, PSE&G sold $71,559,570 of uncollectible receivables to the same vendor for $912,385 (equates to $0.01275 per dollar).[98]

[97] Response to Discovery, OC-1231.
[98] Response to Discovery, OC-1232.

Customer Perception Lead Update

August 18, 2010

Perception Focus Areas

Accountability lies with lines of business to implement and achieve results

Business Area	Lead
Gas Delivery	Mike Schmid
Electric Delivery	Bill Ruffle
Telephone Service	Jane Bergen
Billing	Mike Kelly
CO Field Operations	Heidi Swanson
Customer Service Center	Rich Foley
Small Business Perception	Greg Dunlap
Communications	Mike Scherb
Web	Dan Eichhorn
Training	Tom Robinson
Energy Efficiency & Renewables	Ray Fernandez
Public Affairs & Sustainability	Vaughn McKoy
Information Technology	Bob Czyzewski

Mike Schmid

Dashboard – Gas Delivery

Status:

Key Milestones / Deliverables	Start	End	% Complete	Status
Review and Modify Customer Value Scorecard	Feb	Feb	100%	Closed
Deploy energy savings tips to Gas Delivery Customers and Share with other LOB's	Feb	May	100%	Closed
Social Media Communications initiatives	March	Nov	70%	
Deploy Appliance Service Initiatives	Feb	Dec	75%	
Deploy Gas Distribution initiatives	March	Dec	75%	
Customer Communication Literacy Assessment	April	Oct	25%	
Review metrics and benchmark data and adjust initiatives as needed to improve results	Feb	Dec	65%	
Communicate "in case you are asked"	Jan	Dec	Ongoing	

Major Activities Completed

- Revised the Gas Customer Value Scorecard to include new measures
- Developed and deployed Summer savings YouTube video
- Developed and deployed the Summer Energy Savings Trifold
- Deployed to all customer touching employees- MOT key drivers presentation after mid-qtr results from each qtr
- Partner with Customer Operations - GD view of MOT impacts by CO
- Best Practices Seminar – May 17 and 18
- Modified MOT – Restoration question and trifold dissemination
- Key Driver Tip Sheet stickers for AS and Distr bution
- Deployed a share point site where all customer perception and communication information is housed
- Activated outbound dialer for potential missed appts
- Implemented an electronic construction board and created MOT question for feedback
- Daily Fix-It-Right reviews in Appliance Service
- Appliance Service and Gas Distribution- Soft Skills Program
- Customer Contact Information Sheet to gauge customer communications
- Provided input to the customer satisfaction portion of the BU appraisal
- CGI and Unworkable Process

Key Metrics	Status	Target	2010 YTD (8/1)	July 2010	Q2'10	2009 YE
Gas Delivery – Res Perception	⇧	90	90	90	91	90
Gas Delivery – SB Perception	⇧	89	88	90	88	89
Gas Delivery MOT Process	⇧	9.3	9.2 (Q2YTD)	NA	9.3	9.1
% FIR (MOT)	⇧	NA	85% (Q2YTD)	NA	86%	89%
Appointments Kept	⇔	92%	90%	90%	91%	N/A
BPU Inquiries	⇧	140	75	14	25	204

Major Activities to be Completed

1) Appliance Service- Response times (Schedule optimization – In Progress)
2) Gas Distribution- Job Site Management – Signage/literacy campaign (In Progress)
3) Appliance Service- Appointments Kept (In Progress)
4) Appliance Service- Technician Scorecard
5) Partner with New Business Development organization regarding Small Business/Green programs
6) Youtube video for small business energy savings tip (In Progress)
7) Revisit ChildWatch Program to increase Community presence awareness
8) Develop Carbon Monoxide and gas safety messages for Fire Prevention Week (10/3 thru 10/9). Solicit current volunteer firefighters and EMTs to incorporate information into their community Fire Prevention Week activities.
9) Ensure that Gas Delivery participates in upcoming home/trade shows (such as Trenton Home Show on 10/1 thru 10/3)

All work activities and milestones on track

Some work activities/milestones off schedule, work around plans in place to close gaps, overall schedule on track

Some work activities and / or milestones off schedule, achievement of overall schedule / objectives at risk

Closed

Bill Ruffle

Dashboard – Electric Delivery

Status:

Key Milestones/Deliverables	Start	End	% Comp	Status
Revisit call back process for reliability and meter operations and to further institutionalize the process.	Jan	Sept	80%	
Identify and implement when customer appointments are required	Apr	Sept	80%	
Deliver training to field reps on appropriate positive attributes	Mar	May	100%	
Correct VRU issues.	Jan	Dec	N/A	
Review the estimated restoration time (ETR) process and improve steps to establish, communicate, and update ETR's.	Jan	July	40%	
Identify and implement opportunities to improve visibility and usefulness and more details of the outage map.	Mar	July	90%	
Partner with Customer Operations to support on-going positive customer messages about Electric Delivery Results / Initiatives. On-going initiative.	Jan	On-going	On-going	
Evaluate and support recommendations and provide support in evaluating social networks. Partner with Corporate Communications and Twitter Team.	Jan	Dec	On-going	

Key Metrics	Status	Target	2010 YTD (8/1)	July 2010	Q2'10	2009 YE
Res Perception -- Elec Delivery	⇔	85	83	81	83	84
Res Perception – Outage Info	⇧	77	76	77	75	77
SB Perception – Elec Delivery	⇔	84	82	82	81	82
SB Perception – Outage Info	⇩	76	72	74	70	73
Electric MOT	⇩	9.0	8.6 (Q2YTD)	NA	8.3	8.7
% callbacks		90%				
BPU Inquiries	⇩	215	251	55	88	163

Major Activities Completed

- Identified major 2010 initiatives
- Institutionalized POR call-back process
- Develop tree trimming policy sheet for Customer Ops; Resolve street light calls / OMS / iPower Coding- draft prepared. Policy issued to I.T. for inclusion on website. Presentation and policy completed.
- Support best practice symposium – completed.
- Revised A & I appointment policy with agreement from Customer Operations
- Completed MOT training.
- Posted 28 Twitter postings during July 5th heat storm

Major Activities to be Completed

- Met with Asset Mgmt and O&R Mgrs. Use OMS to collect RFU, RFO, etc call back data. Need to use CAD to capture data. Issues with using OMS & Cad to capture data.
- Meet with Meter departments, discuss A&I process, identify what scenarios require customer to be home, publish agreed upon guidelines for appointments for these scenarios, check against gas A&I process, check that communication on head end of process is aligned with guidelines Appts: Indentify when customer appointments are required. Review is in progress. Conf calls on 6/15/2010 on process.
- Prepare a document that explains the scheduling/appointment process for other types of Electric Customer interface work, check that communication on head end of process is aligned wi h guidelines
- Draft a model for the a phase improvement in communication of ETRs, get consensus and implement. Updated ETR's in march storm.
- Met with the team working on BPU requested website improvements, agree on what part of those improvements should be made available to customers.
- Document funding status and timeline for system changes to address VRU issue

Key Issues Log

- Identify proactive ED actions to influence perception survey
- Set up meetings to review outage maps, outage center and website design. Support goals & objectives. - completed
- Set up meetings to with Twitter Team to support goals & objectives.
- VRU issues postponed until 2011.

All work activities and milestones on track	Some work activities/milestones off schedule, work around plans in place to close gaps, overall schedule on track	Some work activities and / or milestones off schedule, achievement of overall schedule / objectives at risk	Closed

Jane Bergen

Dashboard – Telephone Service

Status:

Key Milestones / Deliverables	Start	End	% Complete	Status
iPower enhancement items (billing screen, C&A,, MO web etc.)	Jan	Aug	70%	
iPower Bill Print enhancements	Feb	TBD	40%	
IVR modifications and tuning	Jan	Dec	60%	
Call Quality (Monitoring and exception reporting)	Jan	Dec	Ongoing	
Training – (continual – transactional and soft skills)	Jan	Dec	Ongoing	
FCR Reporting	Mar	Dec	80%	
Automated Call Back System	Jan	Nov	50%	

Key Metrics	Status	Target	2010 YTD (8/1)	July 2010	Q2'10	2009 YE
Inquiry MOT	↑	8.5	8.4 (Q2YTD)	NA	8.2	8.1
Abandon Rate	↔	5%	5.7%	8.4%	5.2%	15.1
Residential Perception -- Telephone	↑	82	81	83	79	81
Residential Perception -- Easy to Reach by Phone	↓	81	77	74	78	78
Small Business Perception – Telephone	↓	78	72	69	72	75
Small Business Perception -- Easy to Reach by Phone	↓	75	70	68	71	72
Non-Collection BPUs-Inquiry	↓	170	229	29	79	530

Major Activities Completed

Call Monitoring and Tracking being performed – meeting target

- AINV training and reduction in generation
- Training : IA BP name change, Eabico, High Bill Complaint, Web Energy Analyzer, WH, Renewables, SAP enhancements, electronic payments, AC
- July – Bill Print change to eliminate multi bills for cancel/rebills
- First SAP enhancements went live in March – PDFs & C&A; second in May – billing screen, notes history, code 1, call coding

Major Activities to be Completed

- Training: Soft Skills, Renewables, MIMO controls & CSC referrals, weekly huddles, (to be developed – electric fundamentals)
- Phone Pro – began in May – scheduled through September
- Next front office enhancements to go into production August 21
- Increase the amount of representatives listening to recorded calls with a senior or supervisor to focus their attention on how they sound

Key Issues Log

- Analytical support
- Automated Call Back Project – most hardware installed, T1 lines installed, currently finalizing design and testing

All work activities and milestones on track

Some work activities/milestones off schedule, work around plans in place to close gaps, overall schedule on track

Some work activities and / or milestones off schedule, achievement of overall schedule / objectives at risk

Closed

Mike Kelly

Dashboard – Billing

Status:

Key Milestones / Deliverables	Start	End	% Complete	Status
1. Communication plan for multiple bill recipients	Jan 2010	Feb 2010	100%	On going
2. Follow up communication for completed ITMS	Jan 2010	March 2010	100%	On going
3. Feedback to customers with misapplied payments	March 2010	April 2010	100%	On going
4. Billing training targeting high bill explanation	March 2010	April 2010	100%	
5. Compress turnaround time for BEs and all customer support work	Feb 2010	May 2010	100%	On going
6 - Support of system enhancements in the billing and bill print areas	Jan 2010	Dec 2010		
7 – Correspondence tracking via sharepoint	May 2010	June 2010	100%	On going

Key Metrics	Status	Target	2010 YTD (8/1)	July 2010	Q2'10	2009 YE
Res Perception – Billing Index		84	83	84	83	82
SB Perception – Billing Index		81	75	76	75	78
BPUs - Billing		604	390	46	137	604
First Call Resolution		Tracking				

Major Activities Completed

1 – Process established…customers called monthly (200-250)

2 – Process established and ~100 calls take place daily

3 – Process established - letter campaign – 221 letters in April

4 - High-bill focused billing training for contact areas complete

5 – On target to achieve better than pre-iPower performance

- BEs ~2800 per day , ~10K pending
- ITMS ~550 pending (2 days)
- AINV/XMtrs are within 30days ~100 pending
- Sundry work order requests within 3 days ~75 pending
- Long-term rebills within 30 days <50 pending

6 – 10 of the 11 top system break fixes for Billing are in production

7 – Process in place to track and report on high level correspondence

Major Activities to be Completed

5 - Reduce all work volumes to meet or exceed pre-iPower levels

Continue to identify, track, and drive resolution for system and process issues preventing billing

Key Issues Log

All work activities and milestones on track

Some work activities/milestones off schedule, work around plans in place to close gaps, overall schedule on track

Some work activities and / or milestones off schedule, achievement of overall schedule / objectives at risk

Closed

Gerso Quintana

Dashboard – Field Operations

Status:

Key Milestones / Deliverables	Start	End	% Complete	Status
Develop and implement a comprehensive action plan to reduce the District Account Investigation (AINV) Backlog	Jan	Dec	100%	
Develop and implement a comprehensive action plan to Improve Meter Reading Rate	Jan	Dec	100%	
Development and implement tools and guidelines to Reduce Meter Reading Errors	Jan	Dec	90%	

Key Metrics	Status	Target	2010 YTD	Q2'10	Q1'10	2009 YE
Res Perception: Meter Reading	↑	81	80	80	81	80
SB Perception: Meter Reading	↓	81	77	76	77	80
Statewide AINV Backlog	↑	1,000	908	1,129	4,994	3,900
% Meters Read	↔	90.3%	88.0%	87.9%	86.1%	88.5%
Manual MR Error Rate	↑	3.9	2.8	2.8	3.4	3.9
BPUs – Meter Reading	↑	200	119	60	47	339

Major Activities Completed

AINV:

- Conducted FSR Summit to identify performance gap. Developed and documented Process, Procedures and Guidelines. Created a guide of SAP screens and transactions
- Developed and deliver a bi-monthly report to identify potential training opportunities for the CSCs, Inquiry and Billing. Continued performance management of weekly results by FSR / Location
- AINV pilot completed and SubClass/Root Cause identified. High Bill Refresher Training conducted by Districts and Billing.

MR Rate:

- MR Action Plan Developed and bi-weekly review meetings conducted. Joint Process Owner/Meter Reader review and validation team
- District and individual Read Rate targets reset and communicated
- ERT – Chronic Meter and "Safety" policy implemented

MR Errors:

- Error Report now available and reviewed by local supervision for accuracy
- Hi-Low enhancement scoped and moved into produc ion on 5/15.
- Error accountability guidelines rolled out,

Major Activities to be Completed

AINV:

- Call Center & CSC – Continue to monitor 'High Bill' calls/interviews to determine root cause and improve FCR.

MR Rate: System generated monthly MR performance report card in development; Research and validate Web, E-Mail, and other system application opportunities

MR Errors: Coordinate and schedule formal MR refresher training with ETDC as needed

Key Issues Log

AINV: Continual monitoring of unnecessary AINVs issued to the Districts. Reinforce first call resolution of high bill inquiries and related calls
MR Rate: Removal of Vacant/Boarded & unsafe premises' meters from count
MR Errors: Availability of the MR trainer and Camstown

All work activities and milestones on track

Some work activities/milestones off schedule, work around plans in place to close gaps, overall schedule on track

Some work activities and / or milestones off schedule, achievement of overall schedule / objectives at risk

Closed

Dashboard – Customer Service Centers

Rich Foley

Status:

Key Milestones / Deliverables	Start	End	% Complete	Status
Billing refresher training	3/10	4/10	100	
MOT meeting with Supervisors and Denise Kassick	3/10	3/10	100	
Obtain monthly results by CSC as well as verbatims	3/10	3/10	100	
Trainers spending time in CSCs to reinforce training message and work with employees that are lagging behind	4/10	12/10	50	
Conduct Service Pro training for CSC associates	4/10	9/10	100	
Convert digital signage into entertainment system to show movies.	3/10	12/10	10	
Creation and implementation of CSC MOT task force	3/10	12/10	100	
Utilize newly created FCR reports to hold employees accountable for performance	7/19	12/10	0	
MOT Training session with Senior CSRs	4/10	5/10	100	

Key Metrics	Status	Target	2010 YTD (8/1)	July 2010	Q2'10	2009 YE
CSC MOT		9.1	8.3 (Q2YTD)	NA	8.2	8.5
BPU Inquiries		45	28	2	7	49

Major Activities Completed

- All supervisors and Senior CSRs have gone through Service Pro training as well as Coach the Coach sessions
- Mentoring and monitoring sessions are being conducted to ensure Service Pro procedures are adhered to
- Billing refresher training is complete
- Supervisors have met with Denise Kassick to get a better understanding of the survey and weights associated with the questions and each CSC.
- Monthly results will now be obtained for each CSC
- FCR reports have been complete

Major Activities to be Completed

- Billing refresher training is completed
- 95% of CSRs and tellers have been trained in Service Pro, with the remainder to be complete by June 15.

Key Issues Log

- Supervisory staffing levels need to be addressed

All work activities and milestones on track

Some work activities/milestones off schedule, work around plans in place to close gaps, overall schedule on track

Some work activities and / or milestones off schedule, achievement of overall schedule / objectives at risk

Closed

Greg Dunlap

Dashboard – Small Business

Status:

Key Milestones / Deliverables	Start	End	% Complete	Status
PSE&G executive meetings and conferences	3/10	12/10	60	
Outbound Email Call Campaign	4/10	12/10	60	
Technical and soft skills training	04/10	12/10	60	
Marketing campaign leveraging AS and RES efforts	07/10	12/10	20	
Expansion of E-Link Newsletter and Execute Bill Insert Campaign	3/10	12/10	50	
Small business gate performance improvement	3/10	12/10	60	
Offer flexible payment options, deferred payment options and payment assistance	3/10	12/10	60	
Conduct Monthly Webinar Series	3/10	12/10	50	
Promotion and expansion of energy efficiency and renewable programs	3/10	12/10	35	
Outreach Campaign targeting trade associations	6/10	12/10	25	
Better understanding of regional and east external factors driving perception	07/10	08/10	100	

Key Metrics	Status	Target	2010 YTD (8/1)	July 2010	Q2'10	2009 YE
SB Perception (CPI)	⇔	76	74	74	74	74
SB Benchmarking (% in 1st Quartile)	⇓	50%	3% (Q2YTD)	NA	NA	24%
SB (Inquiry) MOT	⇔	8.5	8.3 (Q2YTD)	NA	8.1	7.8
Non-Collection BPU Complaints		NA	121	21	44	201
Collection BPU Complaints		NA	92	53	53	185

Major Activities Completed

- SB Deferred Payment Arrangements – 1,400 offered monthly
- Monitored SB Gate calls for effectiveness – opportunities reviewed with manager.
- Monthly review of BPU inquiries – conducted follow up calls to determine level of satisfaction.
- 140,000 customers called via Davox campaign for email addresses
- Increased Chamber of Commerce membership at the local level and identified PSE&G employees for participation
- Expansion of EnergE Link newsletter to small business customers.
- Trained 178 SB Gate associates on rates, special provisions, meter to cash process and green program offerings
- Email and green programs instruction given to CSR's. Revised CCE's accordingly
- Leveraged J.D. Power award into small business messaging

Major Activities to be Completed

- Execute marketing campaign highlighting customer service improvement. Seek synergies with AS and RES marketing efforts, website enhancement.
- Ongoing efforts to increase email addresses – list to InfoUSA
- Aggressive performance improvement for SB Gate (training and monitor calls for effectiveness).
- Implement employee level monthly SBG scorecard.
- Continue to run new outbound call campaign and new SB Gate infomercial
- Implement new 800 number for small businesses and enhance SB call routing.
- Understanding of SB call activity, i.e. MR errors, LPC, Final Transfer.
- Monthly review of SB specific complaints to understand root cause and identify opportunities for improvement (Initial review completed)
- Ensure participation with Chambers and Trade organizations. Assess feasibility of using outbound campaign and infomercial for SBA, SBDC, UCEDC.

Key Issues Log

- Not at this time

All work activities and milestones on track

Some work activities/milestones off schedule, work around plans in place to close gaps, overall schedule on track

Some work activities and / or milestones off schedule, achievement of overall schedule / objectives at risk

Closed

Mike Scherb

Dashboard – Communications

Status:

Key Milestones / Deliverables	Start	End	% Complete	Status
Develop a comprehensive customer communication strategy to positively impact customer perception.	Jan 1	April 30	100%	
Implement communications tools which help customers understand their bill, positively recognize community and environmental efforts, save money and manage their energy costs and mitigate the impact of rate changes.	Jan 1	Dec 31	50%	
Implement plans to communicate and promote the self service web, billing options and other service enhancements.	Jan 1	Dec 31	50%	
Develop a case to reinstate advertising dollars to influence customer perception.	Jan 1	March 31	NA	

Key Metrics	Status	Target	2010 YTD (8/1)	July 2010	Q2'10	2009 YE
Communications Index (Residential)		78	76	77	75	76
Communications Index (Small Business)		73	69	69	69	70
Energy Efficiency Index (Residential)		73	72	78	71	70
Energy Efficiency Index (Small Business)		69	66	65	65	66

All work activities and milestones on track

Some work activities and / or milestones off schedule, achievement of overall schedule / objectives at risk

Some work activities/milestones off schedule, work around plans in place to close gaps, overall schedule on track

Closed

Major Activities Completed

- Paperless Billing/Web Self Service promotion through: eFYI's, bill inserts, bill messages, service reps, MIMO scripting, website, tips handouts, bill envelope message, WF/ODL DM envelopes, email campaigns, telemarketing, one-pagers for events, small business insert, Outlook Online, Outlook, press releases
- Paperless web survey complete, findings incorporated into campaigns
- Paperless Sweepstakes campaign June/July promoted via bill inserts/messages, website, direct mail 6/9, email campaigns, Service Reps, press release
- Paperless campaigns to AutoPay, Pay by Bank and AnyTime Pay complete.
- JD Power promo on bill envelope
- Field tri-fold handout developed and distributed
- Bill & electronic newsletter articles on "Understanding Your Bill" - Summer Tips (& YouTube promo) – and "What PSE&G is Doing to Control Costs"
- Bilingual tips handout for CSC's, website tips updates, bill message re: pseg.com/saveenergy, Home Energy Toolkit article in Bill Newsletter and May press release
- Small Business perception collateral for contacts/resources including 3 bill inserts, one-pager handout with JD Power promo, bill message. Collateral provided for C of C mtgs, paperless campaign to small bus customers
- Implemented communications plan to mitigate impact of rate increase and leverage positive impacts of MTC and supply decreases including press releases, June eFYI "Lower Gas Bills, Stable Electric Bills"
- High summer electric bill communications included press releases, ta king points for media, bill messaging, on-hold messaging, web site home page (and ICYA and OLOL internally)
- ICYA for customer contact education on Paperless sweepstakes and campaigns, Cap Trans Update, Elec Rate Case decision/impacts, cool customer initiatives, heat wave, gas rate reduction, higher summer bills due to weather
- Solar 4 All press releases, Solar Loan Spanish brochure (non-res), Ad in NJBIZ
- DR – revised web page; development of program collateral for use by AS techs

Major Activities to be Completed

- Paperless campaign targeting remaining My Account customers and unresponsive previously contacted customers to launch with "Plant A Tree" incentive
- PURPA – "Understanding Your PSE&G Energy Bill" insert to run in September
- Understanding Your Bill video/tutorial planned for web and YouTube
- "New improved pseg.com" to announce via insert in September, leveraged with web self-service promo
- Communication of Fall gas supply decrease (October bill newsletter, messaging, website)
- Residential Whole House direct mail in August
- Fall edition of Residential EnergeLink with energy efficiency info in August

Dan Eichhorn

Dashboard – Web

Status:

Key Milestones / Deliverables	Start	End	% Complete	Status
Benchmarking: Identify industry benchmarks/best practices	Jan	Dec	90%	
Work Action Plan items	Jan	Dec	60%	
Improve analytics, including transactional, and MOT survey	Jan	May	80%	
2010 Web promotion plan	Jan	March	50%	
Ease of Use improvements – Spanish, Deep Linking, Web MI/MO	Jan	Aug	80%	
Investigate Apogee commercial energy too kit	April	Dec	0% due to budget	
Move Direct Debit customers to Paperless Billing via Opt-out campaign	May	July	100%	
Use log-in process to promote Paperless Billing, enhance existing program	June	Q4	20%	
PSEG.com Re-design and corresponding changes to MyAccount	Jan	Q3	80%	

Key Metrics	Status	Target	2010 YTD (8/1)	July 2010	Q2'10	2009 YE
Res Perception - % accessed web		NA	NA	NA	25%	21%
Res Perception - % who found info/performed service		NA	NA	NA	79%	72%
Number of Web Accounts Initiated		NA	154434	21638	58814	439103
Number of Active Web Accounts		NA	585160	NA	564015	433897
# of Web Transactions Complete		NA	1566536	238084	1328448	1795469

Major Activities Completed

- Established Web Trends analytics for My Account
- Established additional automatic contacts for web transactions, leading to early identification of 2 system defects
- Completed E Source benchmark review of MyAccount – Action plan developed
- Spanish modules of web experience correctly integrated
- Web promotion plan finalized; advertising campaign is on hold due to cost reductions, while lower-cost items are being completed.

Major Activities to be Completed

- Finalize technical design and content of MOT survey
- August Release to reduce security pop-ups to improve overall site credibility
- PSEG.com re-design on track for August deployment with other MyAccount fixes and the Web MI/MO enhancement
- Business requirements identified and approved for paperless billing enhancement s
- Payment Options Matrix draft to be ready in August

Key Issues Log

- Apogee energy toolkit being considered for 2011
- E Source membership lapsed due to cost considerations

All work activities and milestones on track

Some work activities/milestones off schedule, work around plans in place to close gaps, overall schedule on track

Some work activities and / or milestones off schedule, achievement of overall schedule / objectives at risk

Closed

Tom Robinson

Dashboard – Training

Status:

Key Milestones / Deliverables	Start	End	% Complete	Status
Develop and conduct enhanced training to support Call center and CSCs with iPower	Feb	Jun	100	
Develop and conduct enhanced customer satisfaction training for utility employees including building into all programs and an annual training and assessment of knowledge	Feb	Sept	50	
Build a "customer care" component into all hiring processes	Feb	Sept	10	
Post and provide key customer messages (billing, energy efficiency, etc) throughout Edison Training Center for external visitors (could be part of communications plan)	Feb	Dec	40	

Key Metrics	Status	Target	2010 YTD (8/1)	July 2010	Q2'10	2009 YE
Res Perception-Employee		85	83	83	84	84
SB Perception - Employee		81	78	77	77	79
CO MOT- Inquiry		8.5	8.4 (Q2YTD)	8.2	8.2	8.1
CO MOT – CSC		9.1	8.3 (Q2YTD)	8.2	8.2	8.5
Reduction of AINVs		1,000	919	919	1,129	3,900

Major Activities Completed

- Incorporated 3 presentations from 2009 Employee Experience team into existing training modules
- **Completed enhanced billing training for CSC reps- 10 sessions, 77 participants, Overall Feedback 91% favorable**
- **15 follow-up onsite training/coaching days in CSC's by ETDC instructors**
- Analysis of AINV "top generator" list- one on one follow-up
- CSC new hire training class - Completed
- System review sessions with 50 LCS/CI employees
- **Phone Pro/Service Pro (Customer Interaction) training-Positive feedback** - Over 400 CSR's from CC's and CSC's attended
- Preliminary discussion with UWUA leaders re: training assessments

Major Activities to be Completed

- Instructor onsite follow-up coaching & needs analysis of high priority areas
- **Interaction monitoring processes being improved and implemented**
- Instructor to work with Customer Relations as form of needs analysis
- Supervisory CCS training
- Updated training modules including revised assessments

Key Issues Log

- Training and hiring assessments- Topic deferred until 2011 negotiations w/UWUA
- Identify contacts for training needs assessment from each LOB
- Scheduling and availability of employees for training
- **Reinforcement of the customer interaction training content through effective ongoing transaction mentoring and monitoring processes**

All work activities and milestones on track	Some work activities/milestones off schedule, work around plans in place to close gaps, overall schedule on track	Some work activities and / or milestones off schedule, achievement of overall schedule / objectives at risk	Closed

Dashboard – Renewable & Energy Solutions

Ray Fernandez

Status:

Key Milestones / Deliverables	Start	End	% Complete	Status
Complete 12 formal sessions/appearances with outside stakeholders (developers, municipalities, media, etc) where PSE&G renewable and efficiency programs are promoted.	1/10	12/10	100%	Closed
Develop and submit for approval new programs to address customer segments not included in current program portfolio.	2/10	12/10	75%	Awaiting BPU guidance or request
Partner with Utility Marketing to utilize multiple mechanisms of communication and outreach to promote the availability of energy assistance programs and services.	2/10	12/10	50%	Overall schedule on track
Conduct Tier 3 participation research to determine if improvements can be made	4/10	6/18	100%	CLosed

Key Metrics	Status	Target	2010 YTD (8/1)	July 2010	Q2'10	2009 YE
Energy Efficiency Index (Residential)	↑	73	72	78	71	70
Environment Index (Residential)	↑	74	75	75	76	74
Average Time To Approve Residential Solar Loan	↑	46	NA	NA	61	NA
Milestones Completed	⇔	70%	NA	NA	65	NA
Solar4All Investment Cost/Watt	↑	$6.50	NA	NA	7.59	NA
EE Productivity (total program cost/lifetime kwhr)	⇔	$.036	NA	NA	.034	NA

Major Activities Completed

- AC Cycling Program provided 64 MW of Demand Response to PJM July 7
- BPU approved removal of 500kw cap for Comm. Solar Loan providing 3MW of new applications
- Numerousl public affair initiatives announcing EE and Solar projects were supported . YTD = 32 initiatives.

Major Activities to be Completed

- Collaborate with utilities to submit recommendations for future EE Programs to BPU after senior mgmt. approval in August
- Further develop Marketing Plan for Whole House and AC Cycling program
- Process new Solar residential projects received in July

Key Issues Log

- Collaborate with Bill Ruffle on dual funding of common IT projects for 2011
- Validation of Customers in AC Cycling program database versus SAP billing data base and correct billing (credits) discrepancies by Oct. 1, 2010.
- Implement Solar Loan origination database
- Develop Communication Plan for each EE Program with Mike Scherb & Program Leader

Programs	AC Cycle	Thermostats	Whole House UEZ	Muni	Small Business UEZ	Multifamily	Hospitals	Data Centers	Solar Loans	Solar 4 All (Poles)
# of Customers	120,000	20,000	3500	220	170	25	19	10	33Comm 66Res	33,500
Energy Savings	64 MW	6.4 GWH	6.8 GWH	7.4 GWH	6.5 GWH	0 GWH	38 GWH	0 GWH	15 MW	67 MW

Vaughn McKoy

Dashboard – Public Affairs & Sustainability

Status:

Key Milestones / Deliverables	Start	End	% Complete	Status
Continue to obtain earned media issues addressed in the perception survey	2/10	12/10	50%	
Develop & execute on-line newsletters with key opinion leader	2/10	12/10	55%	
Execute/promote community programs that demonstrate PSEG's corp. citizenry	2/10	12/10	55%	
RPA: develop process/criteria to determine participation organizations; enhance employee participation on boards	3/10	5/10	100%	
RPA: integrate Small Businesses into sponsorship criteria	3/10	5/10	100%	
Foundation: Engage grantees through 5 workshops and training opportunities	2/10	12/10	60%	
RPA: Implement 8 regional public affairs forums with key municipal stakeholders	1/10	12/10	50%	
Conduct 2 surveys to gauge perceptions on PSEG thought leadership and measure community/environmental awareness.	3/10	12/10	55%	
Leverage media opportunities to publicize and PSE&G Offering and Programs	2/10	12/10	55%	
Partner with PSE&G Community Development to maximize exposure of upcoming NRTC grant presentations	3/10	12/10	55%	

Key Metrics (Residential Perception)	Status	Index Target	2010 YTD (8/1)	July 2010	Q2'10	2009 YE
Company you can trust	⇧	82	82	83	81	83
Good corporate citizen in the communities	⇔	82	80	81	80	81
Protecting the environment	⇧	74	78	75	78	76
Supporting alternative energy sources	⇧	74	73	75	73	71

Major Activities Completed

- Support Center for Non-profits Corp., Ask the Funder Sessions
- Dana Christmas Scholarship Fund Dona ion $50,000
- PSEG Crisis Fund Sof ball Game
- Lincoln Park Music Festival – Haitian Pavilion
- Center for Hispanic Policy Interns Leadership Day at PSEG
- Statewide Hispanic Chamber of Commerce Scholarship Gala. LaRossa, co-chair
- Taping of Giants Commercial wi h PSE&G Children's Specialized Hospital
- Marion P. Thomas Charter School
- Graduation Guest Speaker, Gray Charter School
- Energy & Environment Advisory Committee meeting with groups
- Hispanic Policy, Research and Development Gradua ion Ceremony
- Non-profit and Advocacy Groups Outreach Plan
- Opinion Elite Survey – Wave 1 Completed: 87 surveys of Opinion Elite (defined as leaders in business, government, education, non-profit and community organizations across New Jersey) yielded the following results:
- PSEG continues to be the top mentioned company among Opinion Elites in Q2'10 on perceptions of its commitment to he environment and has increased it proportion of the total mentions from 29% in 2009 to 40% in Q2'10. The current level is above the 2010 target for this measure (29%).
- Perceptions of PSEG being the most respected company for its commitment to good corporate citizenship have rebounded from the decline measured in Q4'09 (19% from 8%) and is above the 2010 target level of 14%.

Major Activities to be Completed

- Media - Obtain 20 stories in weekly papers; Obtain 15 successes in NJ daily papers/magazines; Execute 1 blogger event; Obtain 5 executive appearances on NJ/Philly TV
- Public Affairs - Coordinate and support 15 NJ speaking opportunities for PSEG executives; executive 5 stakeholder briefings; communicate at least 10 times wi h NJ thought leaders
- Somerset Patriots Softball Game, Hoskins throwing out 1st pitch, 8/30
- Sustainability Report to live online—stakeholders notified via newsletters and press release
- Executive Women Luncheon – Commissioner Lori Grifa – 9/10
- NJ After 3 After Conference, 9/23
- EDC recognition ceremony for PSE&G support for housing, 9/24; Governor's Conf., 9/28
- Environmental Stakeholder mtg, 9/29; Non-Profit Briefing, 9/30;
- United Way and Environmental Education Grants and Check Presentation, 10/1-15
- PSEG QLF Meeting & Volunteer activity; 10/1
- NJPAC Gala, Ralph Izzo Co-Chair, 10/2
- New Jersey Inventors Hall of Fame, R. Izzo, 10/14
- Power Lunch at Public Service, 10/15; Naval Academy Outreach and Recruitment, 10/ 19-23
- PSEG Children's Specialized Hospital Game Day @ Giants Stadium, 10/17
- PSE&G Children's Specialized Hospital and Giants Game Day, 10/17
- Bethany Cares 10th Anniversary, Ralph Izzo, Honorary Chair, 10/24
- PSEG Institute of Sustainability Studies –Fall Conference 10/25

All work activities and milestones on track	Some work activities/milestones off schedule, work around plans in place to close gaps, overall schedule on track	Some work activities and / or milestones off schedule, achievement of overall schedule / objectives at risk	Closed

Bob Czyzewski

Dashboard – IT

Status: Green

Key Milestones / Deliverables	Start	End	% Complete	Status
Complete 38 iPower enhancement projects on time and on budget.	Jan	Dec	88%	Green
Provide technical and consulting services for social networking (Blog, Facebook, YouTube, Twitter) solutions.	Jan	Dec	40%	Green
Develop and deliver BPU Storm Dashboard and proposal for updated customer outage map.	April	Dec	25%	Green
Implement Web utilization plan, IVR improvements, and other system enhancements identified throughout Customer Perception Plan.	Jan	Dec	20%	Green
Deliver eApps strategy and 5-year investment plan to support Customer Perception objectives in 2010 and beyond.	May	Sept	10%	Green

Key Metrics	Status	Target	2010 YTD (8/1)	July 2010	Q2'10	2009 YE
Percent iPower enhancements in production.	⇧	NA			16%	N/A

Major Activities Completed

- 24 iPower enhancements in production with 16 additional items staged and ready for July release.
- Gas Appliance Service MDT synch time improvements.

Major Activities to be Completed

- Mobile VPN pilot to improve Gas Appliance Service productivity (MDT connectivity and application issues).

Key Issues Log

- None

All work activities and milestones on track

Some work activities/milestones off schedule, work around plans in place to close gaps, overall schedule on track

Some work activities and / or milestones off schedule, achievement of overall schedule / objectives at risk

Closed

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23. Salary, Wage and Compensation, and Benefits

Introduction

Human Resources (HR) management focuses on hiring, developing, motivating, evaluating and compensating employees. HR functions are important both in terms of direct costs and corporate performance.

Our review encompassed the full range of HR functions and is divided into four chapters. This first chapter addresses the following areas.

- Compensation
- Employee Benefits

Chapter 24 addresses:

- Productivity Analysis
- Staffing Levels
- Human Resources Strategy

Chapter 25 addresses:

- Leadership and Employee Development
- Training
- Performance Evaluation
- Recruitment and Hiring

And finally, Chapter 26 addresses:

- Labor Relations
- Equal Employment Opportunity Programs
- Affirmative Action Programs

Summary of Findings

1. PSEG's compensation philosophy is designed to foster a "Total Rewards Mentality".
2. Merit Increases Support Competitive Compensation Objectives.
3. Lump Sum Payments in lieu of base pay adjustment are an important tool to reward solid performers high in the range of their position.

4. Cash bonuses recognize contributions of employees below officer level.
5. Equity Adjustments address inconsistencies between employees in base salaries.
6. Job Evaluation / Market Pricing result from the creation of new positions or changes in responsibility of existing positions.
7. PSEG uses a Suite of Surveys for compensation data and targets the 50th Percentile for its employees.
8. The system utilized to perform Non-Represented Employee Performance Evaluations, Empower, is very effective.
9. Role of Human Resources in Organizational Structure and Position Descriptions is advisory and consultative.
10. Three separate incentive programs cover non-union, non-executive staff; executive staff; and the most senior executive staff.
11. PSEG Senior Management Incentive Compensation Program is designed to foster the attainment of financial and operating objectives among executives and other important positions.
12. Performance Incentive Plan for Certain Employees is designed to foster financial and operating objectives among employees.
13. Public Service Enterprise Group Incorporated Management Incentive Compensation Plan is designed for key officers and executive level employees.
14. Public Service Enterprise Group Incorporated 2004 Long-Term Incentive Plan is designed to attract and retain best personnel in substantial positions.
15. Despite the number of plans and the benefits provided, PSEG compares favorably with its Peers regarding the cost of its benefits programs.

Recommendations

1. While structured and effective, Empower needs simplification for employees receiving less than satisfactory evaluations.
2. While the performance evaluation processes for Represented Employees also are strong, there is a need for clarification and simplification of the forms related to the electrical and gas delivery evaluations.
3. PSE&G should develop an organizational manual and reconsider some spans of control.
4. Position descriptions should be expanded and provided for all positions.
5. The large number and wide variety of PSEG benefits programs are difficult to follow and presumably to administer. The company could benefit from a summary document of these various programs by type, eligible employee, and benefits provided.

Executive Compensation

Comparison to Peer Group

Compensation Philosophy and Program. PSEG indicates it has designed an Executive Compensation Program (Program) to attract, motivate and retain high-performing executives who are critical to our long-term success. They have structured the Program to link executive compensation to successful execution of their strategic business plans and meet their financial, operational and other corporate goals. This design is intended to provide executives increased compensation when the company does well as measured against its goals and delivers on shareholder expectations and to provide less compensation when the company does not.

In setting compensation for a particular executive, the company's philosophy is to use the median of compensation of similar positions within an identified peer group of energy companies as a reference point, which is then adjusted based on the performance and experience of the individual, the individual's ability to contribute to long-term success and other factors, such as relative pay positioning among executives.

The philosophy and objectives of the Program are reviewed at least annually and any proposed changes are presented to the Organization and Compensation Committee of the Board of Directors (the Committee) for its approval. The compensation philosophy, strategy and programs are reviewed to ensure they accomplish the following objectives:

- Drive and reward performance;
- Align with long-term shareholder value creation;
- Allow PSEG to attract and retain the talent needed to effectively execute its strategy; and
- Provide a competitive total compensation opportunity without encouraging excessive risk.

Compensation Consultant. In September 2009, the Committee retained CAP, an independent executive compensation consulting firm, to provide information, analyses and advice regarding executive and director compensation. Prior to that time, the Committee engaged Mercer to provide these services. The consultant who performs these services reports directly to the Committee and the Committee has established procedures that it considers adequate to ensure that CAP's advice to the Committee is objective and is not influenced by management. These procedures include: a direct reporting relationship of the consultant to the Committee and an agreement specifying what information can and cannot be shared with management. CAP provides only executive and outside director compensation consulting services.

Peer Group. The company sets executive compensation to be competitive with other large energy companies within an identified peer group. They consider 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. The current peer group was first used in 2008. They review the peer group each year and believe it continues to reflect their industry competitors in the market from which they recruit executive talent. This peer group is used as a reference point for setting competitive executive compensation and was developed to reflect similarly-sized energy companies with comparable businesses. The Committee targets the median (50th percentile) of this peer group for positions comparable to those of PSEG officers for Total Direct Compensation. The peer group is also used for comparison in assessing their performance under the long-term incentive plan as well as an overall validation of the alignment between pay and performance.

The peer companies are as follows:

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.

Table 23-1 shows a comparison to PSEG's peer companies based on the most recently available financial data.

Table 23-1 – Comparison of PSEG Peer Companies

Comparison of PSEG Peer Companies (Millions)			
Description	2008 Revenue ($)	2008 Net Income ($)	Market Cap at 12/31/08 ($)
Peer Group 75th Percentile	16,320	1,447	19,384
Peer Group Median	13,848	1,302	13,640
Peer Group 25th Percentile	12,621	1,079	10,517
PSEG	13,807	1,192	14,763

The data used for the comparisons below are from the most recent data available for the companies in the peer group. The Committee considers a range of 85% to 115% of the 50th percentile of comparable positions to be within the competitive median.

For 2009, base salary, target Total Cash Compensation and target Total Direct Compensation of each of the Named Executive Officers (NEOs) included in the Proxy Statement (except Mr. O'Flynn whose employment terminated in April 2009) as a percentage of the comparative benchmark levels of the peer group was as shown in Table 23-2 below:

Table 23-2 – Percent of Comparative Bechmark Levels

Percent of Comparative Benchmark Levels					
Name	Izzo	Dorsa	Levis	Mehrberg	LaRossa
Base Salary	77	98	101	132	95
Total Cash Compensation	89	92	101	136	92
Total Direct Compensation	96	91	103	116	99

For 2010, base salary, target Total Cash Compensation and target Total Direct Compensation of each of the NEOs included in the Proxy Statement as a percentage of the comparative benchmark levels of the peer group are as shown in Table 23-3 below:

Table 23-3 – Percent of Comparative Benchmark Levels

Percent of Comparative Benchmark Levels					
Name	Izzo	Dorsa	Levis	Mehrberg	LaRossa
Base Salary	78	102	93	106	107
Total Cash Compensation	91	96	93	110	105
Total Direct Compensation	94	88	92	101	105

All of the NEOs, except Mr. Mehrberg, were at or below the comparative benchmark levels for 2009. Mr. Mehrberg began his employment in September 2008. The changes from 2009 to 2010 reflect additions in responsibilities assigned to Mr. Mehrberg and compensation changes at the peer group companies, as all components of NEO salaries were frozen for 2010.

Total compensation figures for FY 2007-2009 for the top five executives of PSEG along with their positions are presented in Table 23-4.[1]

[1] Definitive Proxy Statement, Schedule 14A Information, March 2, 2010.

Table 23-4 – Summary Compensation

Summary Compensation Table									
Name and Principal Position (1)	Year	Salary ($) (2)	Bonus ($)(3)	Stock Awards ($)(4)	Option Awards ($)(5)	Non-Equity Incentive Plan Compensation ($)(6)	Change In Pension Value and Non-Qualified Deferred Compensation Earnings	All Other Compensation ($)(8,9,10)	Total $
Ralph Izzo Chairman of the Board, President, and CEO	2009	946,450	-	2,360,804	2,362,241	1,345,000	1,585,000	116,475	8,715,970
	2008	944,342	-	2,530,763	2,537,424	1,000,000	878,615	232,099	8,123,243
	2007	845,388	100,000	5,042,288	4,332,688	1,282,500	665,930	208,405	12,477,199
Caroline Dorsa Executive Vice President and CFO	2009	386,589	204,322	1,045,027	780,117	277,300	1,871,000	46,095	4,610,450
	2008								-
	2007								-
Thomas M. O'Flynn Executive Vice President and CFO	2009	265,220	-	-	-	101,589	657,000	2,014,648	3,038,457
	2008	614,932	-	483,294	483,472	384,800	308,650	44,983	2,320,131
	2007	596,034	50,000	1,170,184	1,121,828	540,000	170,363	67,028	3,715,437
Randall E. Mehrberg Executive VP (Strategy and Dev. Serv.); President and COO	2009	542,963	250,000	399,267	399,931	357,100	452,000	118,931	2,520,192
	2008								-
	2007								-
William Levis President and COO (Power)	2009	543,960	-	474,359	475,300	374,000	471,000	156,490	2,495,109
	2008	543,285	-	509,418	510,272	355,700	182,000	616,433	2,717,108
	2007	491,657	516,667	4,219,732	891,590	454,200	1,710,000	70,153	8,353,999
Ralph A. LaRossa President and COO (PSE&G)	2009	464,728	-	375,458	374,808	285,500	1,728,000	39,449	3,267,943
	2008	422,471	-	401,657	403,072	286,100	231,000	60,031	1,804,331
	2007	377,431	-	783,237	756,740	342,000	195,000	48,474	2,502,882

Regular Compensation

[Begin Confidential]

Table 23-5 – Salary and Incentive Structure for 2009

[redacted]

[2] Response to Discovery, OC-142.

[3] Response to Discovery, OC-142.
[4] Response to Discovery, OC-142.

Table 23-6 – Merit Pay Decision Guide for the 2009 Compensation Structure

[redacted]

[5] Response to Discovery, OC-142.
[6] Response to Discovery, OC-142.

[7] Response to Discovery, OC-142.
[8] Response to Discovery, OC-142.

[End Confidential]

Surveys Used for Compensation Data

PSE&G uses a Suite of Surveys for compensation data and targets the 50th Percentile for its employees. For middle and upper level positions, the company uses national level data for comparison purposes and regional and local area data is used for lower level positions. PSE&G targets the 50th percentile of the peer group of energy services companies for targeting compensation levels and managing pay delivery. The primary source of competitive compensation for PSE&G's positions is the Towers Watson's (TW) suite of surveys for executive and non-executive[11] positions.

Employee Evaluation and Performance

Non-Represented Employee Performance Evaluations

The system utilized to perform non-represented employee performance evaluations, Empower, is very effective. The HR system utilized by PSEG for employee performance evaluations of non-represented employees is entitled "Empower". The system is purchased from a vendor named SuccessFactors, which provides the technology for Empower. According to PSEG literature "The Performance Partnership discussion provides the opportunity:

- for ***formal*** performance feedback to employees at mid-year and again at year-end to reinforce on-going feedback throughout the year
- to discuss employee development - targeted job knowledge, skills enhancement - and progress against specific goals
- to discuss performance rating level and, if necessary, address the need for a Performance Management (improvement) Plan
- to agree on goal outcomes/areas for balance of calendar year (year-end) if applicable."

[9] Response to Discovery, OC-142.
[10] Response to Discovery, OC-142.
[11] Responses to Discovery, OC-57, OC-31, and OC-663.

Further, the system is touted for its ability to:

- Strengthen the link between individual performance and PSEG business goals and initiatives.
- Enhance communication between managers and employees.
- Improve managerial planning and coordination.
- Shift the focus from a single event to an ongoing process that supports the company's culture and enhances results.
- Balance results with desired behaviors and continued growth and development of employees.

A schematic of the Performance Partnership Workflow is presented in Table 23-7 and a summary and timetable of the process for 2009 is presented in Table 23-8.[12]

[12] Response to Discovery, OC-152.

Table 23-7 – Performance Partnership Work Flow for 2009

Table 23-8 - Summary and Timetable of the Process for 2009

Step	Start	End	Action Required
Self-Evaluation	1-Dec-09	15-Dec-09	Employees submit self-evaluation to their managers (Step 5)
Manager Assessment	15-Dec-09	4-Jan-10	Managers enter and submit ratings and comments and send to HR to be review ed during cal bration (Step 6)
Calibration - I	16-Dec-09	11-Jan-10	Cal bration - I - Organizations manage their cal bration process and dates and complete the preparation necessary for form Cal bration II - CEO direct report level calibration (Step 7)
Calibration - II	11-Jan-10	15-Jan-10	Cal bration - II - CEO-direct report's review and cal bration of ratings (Step 7 cont'd)
Calibration - III	18-Jan-10	22-Jan-10	Cal bration - III - CEO overall review and approval of ratings (Step 7 cont'd)
Discussion	25-Jan-10	1-Mar-10	Managers discuss performance and ratings w ith employees (Step 8) after CEO approval
Option: Discussion pay and performance	23-Feb-10	26-Feb-10	Managers discuss performance and ratings w ith employees and share total compensation statement w hen available on or after 2/23/2010 (Step 8) after CEO approval
Acknow ledge Receipt and Close Out	2-Mar-10	12-Mar-10	Employees acknow ledge receipt of form and Managers sign form electronically

Our review of the Empower system caused us to agree with many of the assertions made in the PSEG literature regarding the system. For example, we found that Empower specifies the PSEG values of accountability, continuous improvement, customer focus, diversity, integrity, respect and safety. Further, Empower details the behavioral standards expected to be exhibited by each level of employee (individual contributors, supervisors/managers, and directors/executives) related to each of the values.

Other claims regarding Empower in the PSEG literature that we were able to verify include the following.

> *The performance partnership process is designed to assist managers and employees with a bi-annual assessment of an employee's performance by a performance goal setting and goal monitoring process, a values and behaviors evaluation, and evaluation of the employee's execution of overall job responsibilities. The Performance Management Toolkit is a document which is made available to PSEG employees which describes the process which is used throughout PSEG for all MAST employees' performance*

evaluations. The bi-annual assessment is carried out by both employee and immediate manager jointly. The referenced toolkit provides guidelines, examples, definitions and explanations of the various aspects of the assessment process and format including such components as the PSEG Performance Partnership Form and Values and Behavioral Standards. Employees and managers are also provided with the description of Performance Levels and the basis for their application. There are Performance levels or performance ratings, namely: Exceptional, Exceeds Expectations, Fully Meets Expectations, Partially Meets Expectations, and Unsatisfactory. There are two additional designations but they are not true measures of actual performance: New (employee is new to PSEG without sufficient service time to warrant a valid assessment) and Unable to Rate (usually reflective of an employee on long term leave (disability, military). [13]

The Values and Behavioral Standards define the seven PSEG Values on which the PSEG behavioral model is based. Behaviors are given significant importance in the performance partnership to support the management philosophy that the way in which results are achieved are just as important as the results themselves. While Performance Partnerships have a required frequency of twice a year, the PSEG is committed to continuous improvement through continuous feedback and manager coaching. The Performance Partnership Discussion Toolkit is designed to give managers guidance and support for the most optimal ways to conduct performance discussions, to keep performance directed in a positive direction, to identify performance issues early and drive to performance recovery quickly. The overall objective of the Performance Partnership process is to build high performing teams by building up individual performance.

[Begin Confidential]

[13] Response to Discovery, OC-152.

[End Confidential]

Need for Clarification and Simplification of Forms

While the performance evaluation processes for Represented Employees also are strong, there is a need for clarification and simplification of the forms related to the electrical and gas delivery evaluations. The Evaluation philosophy for represented employees is as follows:

- Consistent appraisals will communicate to the employee if management's expectations are met and recognize and sustain good performance.
- A comprehensive appraisal will help the employee to the best of their abilities.
- An honest, objective appraisal will give the employee areas in which they need improvement or further development.
- A thorough appraisal will help the employee set "long term" career goals.
- Complete appraisals will help supervisors select the most competent employees for promotions.
- Accurate appraisals are key to ongoing performance management.

During the review meeting, the employee and the evaluator should discuss specific strengths and improvement opportunities, citing specific examples and the employee is encouraged to write in comments. At the completion of the review meeting, the evaluator and employee sign and date the evaluation form. A completed copy of the employee's performance evaluation is provided to the employee and the original is placed in the employee's personnel file.[15]

Customer Operations

Our evaluation of the Customer Operations Appraisal Form is as follows:

- Thorough document
- Clear, specific, explicit instructions to the evaluator
- Drives interaction between employee and supervisor
- Clear and explicit guidance related to the 5 performance levels

[14] Response to Discovery, OC-152.
[15] Response to Discovery, OC-152.

- Significantly exceeds standard
- Above Standard
- Meets standard
- Marginal
- Below standard

- Clear and concise definition of areas to be rated, e.g., quality of work, productivity/quantity of work, customer/client relations
- Drives "forward vision" by insistence on addressing areas such as "Performance objectives for next appraisal cycle" and "Employee Career Interest".

Electric and Gas Delivery Appraisal Form

Electric Delivery Appraisal and Gas Delivery Appraisal Form. Our evaluation of the Electric Delivery and Gas Delivery Appraisal Forms is as follows:

- Instructions not as clear and detailed as for Customer Operations
- Instruction #4: It is required to write in every comment section" implies a level of perfunctory performance or forced interest on the part of the evaluator
- Definitions in Instruction #6 are not clear
- Evaluation format less structured and explicit than customer operations or non-represented employees. More judgment left to the evaluator regarding what goes into the evaluation than other systems/methodologies reviewed.

Organizational Structure & Position Descriptions

Need for Organizational Manual

PSE&G should develop an organizational manual and reconsider some spans of control. At the highest level the PSE&G organization is broken into eight organizational units as shown in Table 23-9. Each of these is further subdivided. For example, Customer Operations is divided into eight sub-units as shown in Table 23-10. One of these subunits (Customer Relations and Community Relations) is divided into Customer Service Centers and Customer Operations Administrative Support (Table 23-11). The Customer Service Centers is subdivided into 16 regional Customer Service Centers (Table 23-12). Similar structures exist for the eight organizational units shown in Table 23-9.[16]

While we will not present the entire 40 pages of organizational charts for PSE&G that was provided to us, we will discuss those elements that raise concerns. First, there is no organizational manual that provides mission, functions, and activity statements which must make it difficult to ensure that good organization principles are observed. For example, are similar functions grouped together?, is there overlap between the functions of distinct organizational units, are similar functions grouped together or in different units?, are all important functions address by an organizational unit?, are dissimilar functions grouped inappropriately in the same organizational unit?, is there duplication of functions?

[16] Response to Discovery, OC-156.

Without an organization manual, such analysis would have to be performed using the position descriptions making it difficult and inefficient.

Another question raised by the organization chart for the Customer Service Centers is whether the span of control (16) is too broad for one manager to oversee. A similar question arises for the Southern Division Gas Distribution AS (80000806). (See Table 23-13). The opposite question occurs in reviewing the Office of the Corporate Rate Counsel: (30000427) (Table 23-14). In this case there is one office overseeing just one office which again oversees just a single office.

Position Descriptions

Position descriptions should be expanded and provided for all positions. We reviewed in excess of 500 position descriptions provided by PSEG for non-represented position at the manager or above level. These documents were presented in chart form and were brief and in a summary format. We had a number of concerns regarding the format and content presented to us. First, a few position descriptions were not available. In lieu of the position description, there was an explanation that the position was being researched or the document was inexplicably unavailable or simply didn't exist. Of the first 41 positions reviewed, 11 (27%) were not initially available. PSEG later provided a supplemental document that showed position descriptions for several positions where a position description was not originally available. However, several position descriptions are still missing for high level positions, e.g., Dir Design Eng, Eng & Operations Svcs; and Dir Employee Relations & Enterprise Outreach. We do not offer this as a representative sample, but we do think it indicates that a few position descriptions are missing throughout the documents provided.[17]

Other concerns with the position descriptions presented are:

- Such brief description could make it difficult to identify overlap and duplication among functions or identify required functions that may not be assigned to anyone;
- Similarly, the brevity of the description (or no description) can make it difficult for an employee, especially a new one to fully understand, take responsibility for, and perform all of the duties that is expected;
- Such brief descriptions, and certainly missing descriptions make it difficult to objectively and adequately evaluate employee performance.

HR Role

Role of Human Resources in Organizational Structure and Position Descriptions is advisory and consultative. Human Resources (Client Relations) assists line managers in the design of organizational structure if a particular organizational unit is initially being structured or if it is being restructured. Line managers have the primary responsibility for structuring organizational units. Human Resources' role is advisory, providing principles and concepts for use by the line manager. HR looks at the proposed structure for rationality. Line managers are required to consult Human Resources. HR takes a more

[17] Response to Discovery, OC-73 and OC-73 SUPPLEMENTAL.

active role if staff is being increased or reduced. If staff responsibilities are being changed, HR Compensation must become involved in determinations. HR Client Relations checks new position descriptions to ensure there is no duplication or dysfunctional assignments. For very large reorganizations (e.g., the one involving the Safety Reorganization), the President of the Line of Business will approve.

In addition, cross functional reviews are completed throughout the organization on a regular basis. The most recent one was completed in the first quarter of 2010 and resulted in documentation. That review looked at all organizational structures across the company. Finally, an Organizational Effectiveness Initiative is performed on a periodic basis since the merger with Exelon failed.

Similarly, position descriptions are a shared function between Compensation (HR) and the involved line of business. The description is developed by the line of business; Compensation ensures consistency within the company (market pricing). A position description is required for new positions or positions that have significant responsibility changes; a lengthy Position Description Questionnaire must be completed.[18]

We believe the relationship between Human Resources and Line managers to be one of strength within PSE&G. Line managers are responsible for developing and modifying organizational structure while Human Resources serves in a consulting/advisory role. This gives Line Management ownership of new and revised structures which is important since they have the responsibility to make it work.

[18] Interviews with Vince Labbatte and Randi Casey 4/12/2010 and with Christine DeStefano on April 26, 2010 at 2:00 PM.

Table 23-9 - High Level Organizational Structure of PSE&G

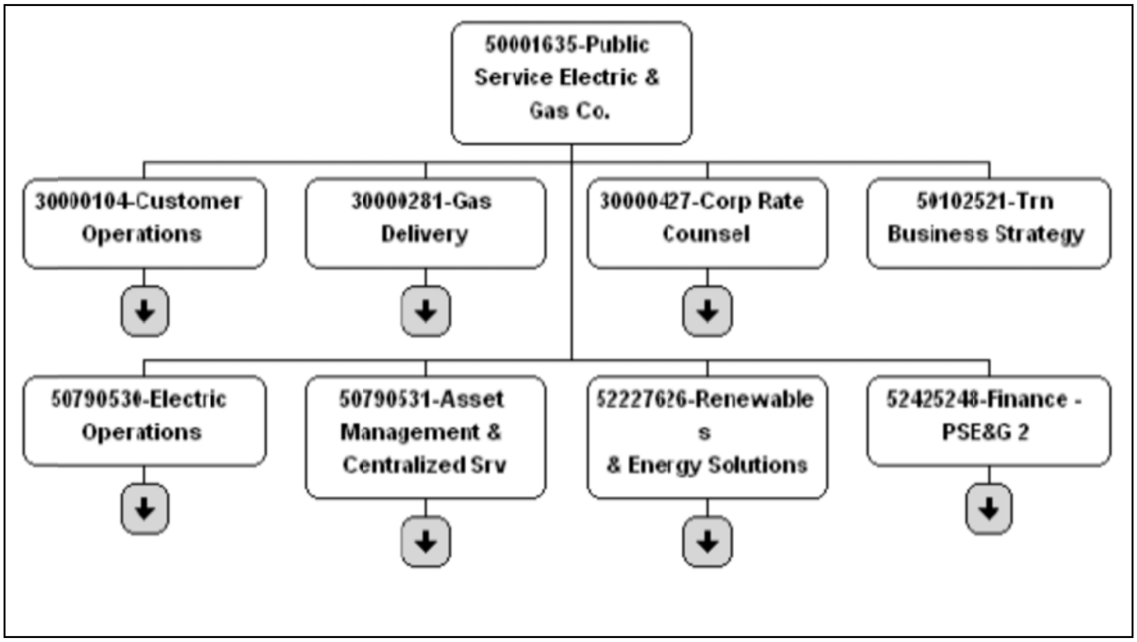


Table 23-10 - Organizational Structure for Customer Operations

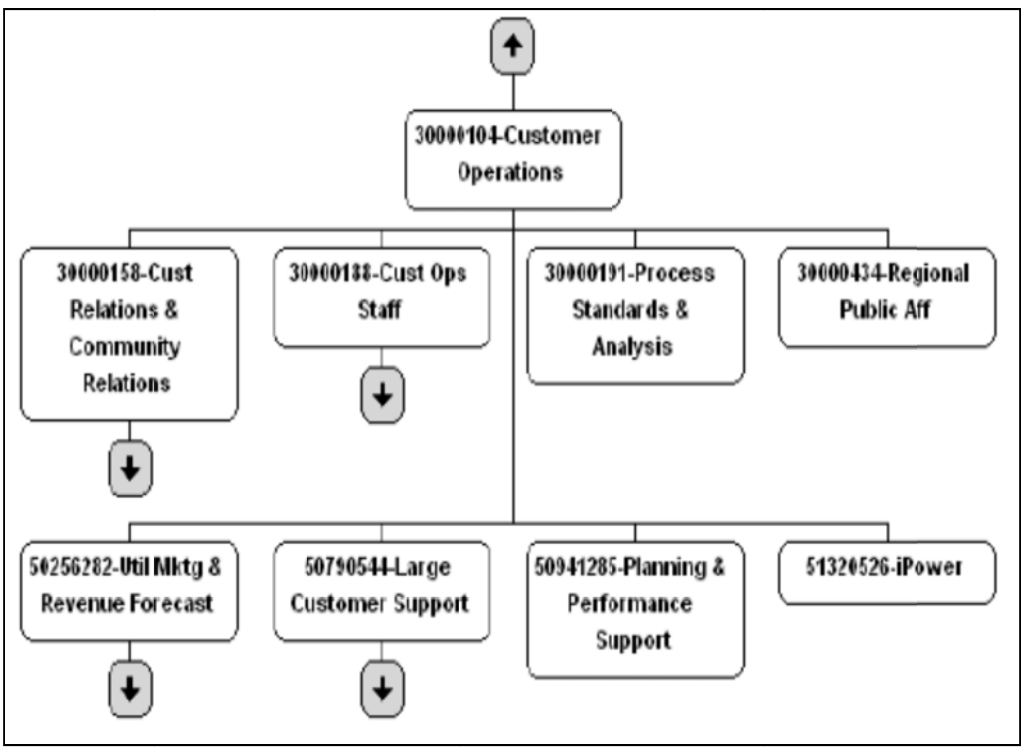


Table 23-1 . - Organizational Structure for Customer Relations and Community Relations

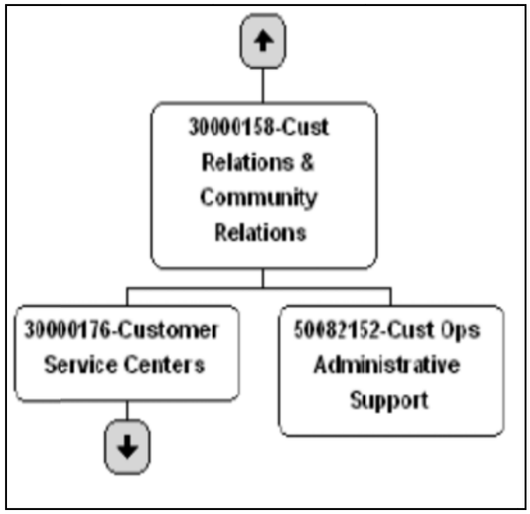


Table 23-1 - Organizational Structure for the Customer Service Centers

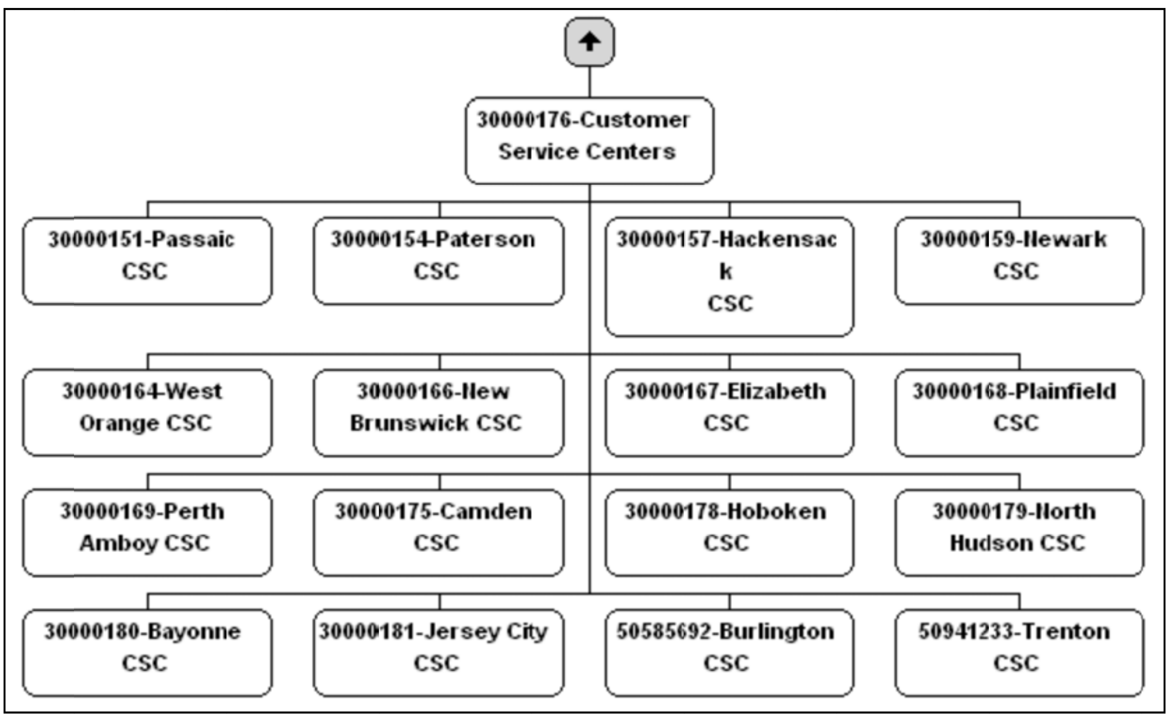


Table 23-13 - Organizational Structure for the Southern Division Gas Distribution AS

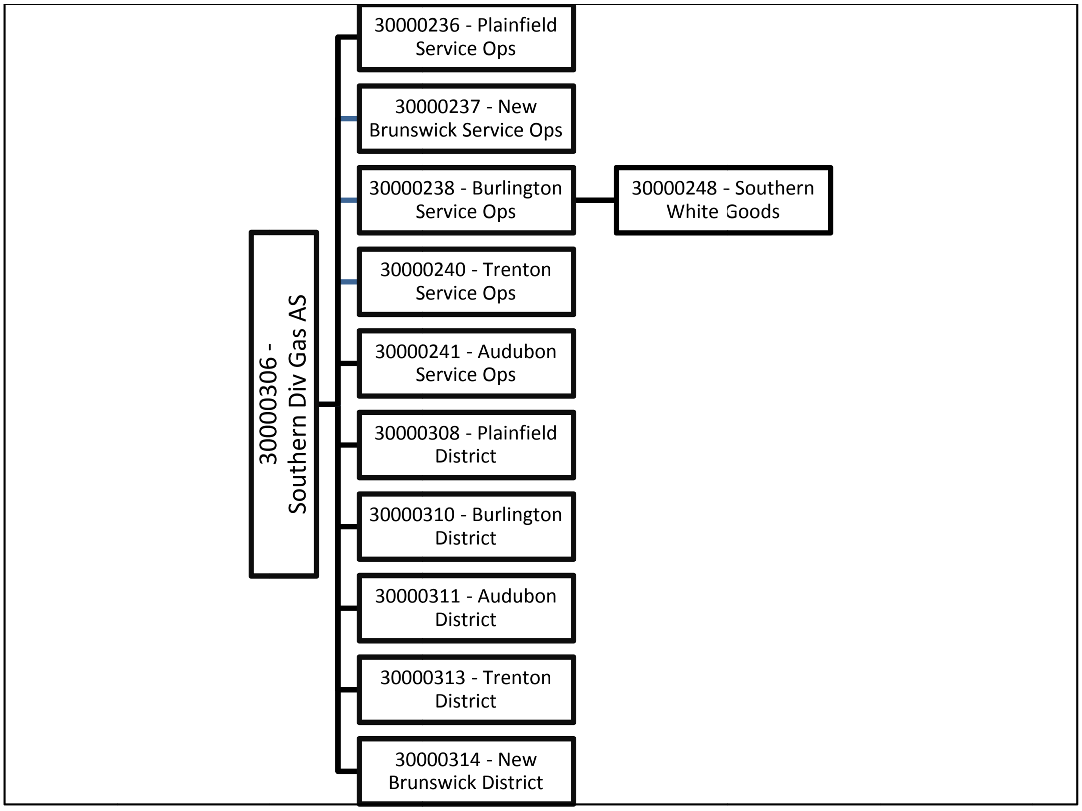
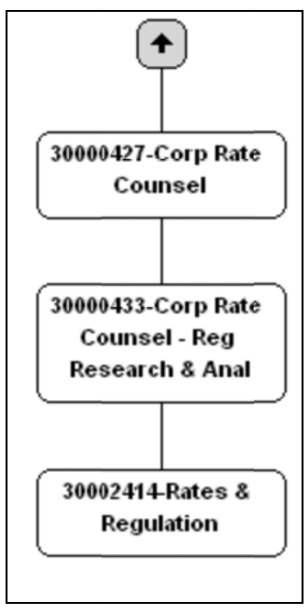


Table 23-14 - Organizational Structure for the Office of the Corporate Rate Counsel



Incentive Programs

Three Separate Incentive Programs

Three separate incentive programs cover non-union, non-executive staff; executive staff; and the most senior executive staff. The performance programs under executive management review covering PSEG's non-union, non-executive employee group (MAST) are titled "Performance Incentive Plan" or PIP. There are four plans that cover MAST employees with a separate plan for PSE&G, PSEG Power, PSEG Services and PSEG Holdings. These plans are identical in basic design and differ only with respect to several administrative requirements.

An executive level program, under the management of the Organization and Compensation Committee of PSEG's Board of Directors, is entitled the Senior Management Incentive Compensation Plan or SMICP. This plan, along with MICP and PIP, are annual cash incentive compensation programs that provide variable pay opportunity for plan participants based on meeting corporate and business level goals and objectives. The plans are designed to provide, at targeted results, a level of total cash compensation that is competitive with what other large companies provide similar positions in the energy sector.

Another performance program is PSEG's long-term incentive compensation program, specifically, performance shares and restricted stock shares. Performance shares are granted annually to executive level participants and any payout from any given grant is dependent on achieving two financial measures over a three year performance measurement period. Awards are dependent on meeting financial targets and the award can range from no award to 2x the original grant level. For example, an executive receiving a grant of 1,000 performance shares can expect to receive a final award ranging from zero shares to 2,000 shares based on results against goals.

Performance shares were reintroduced in 2007 with the first payout scheduled for March 2010. The measures used to determine payouts with respect to the most recent grant of performance shares are based on Total Shareholder Return (TSR) relative to a 16 company peer panel and Average Return On Invested Capital (ROIC) vs. plan.[19]

[Begin Confidential]

[19] Response to Discovery, OC-134.

Table 23-16 – Performance Units/Shares

[redacted]

Table 15 (continued)

[redacted]

[End Confidential]

PSEG Senior Management Compensation Program

PSEG Senior Management Incentive Compensation Program is designed to foster the attainment of financial and operating objectives among executives and other important positions. This Plan is designed to provide for awards to executives, who, individually or as members of a group, contribute in a substantial degree to the success of the Company and its Participating Affiliates, and who are in a position to have a direct and significant impact on the growth and success of the Company and its Participating Affiliates, thus affording to them a means of participating in that success and an incentive to contribute further to that success. This Plan also serves to supplement the Company's and Participating Affiliates' salary and benefit programs so as to provide overall compensation for such executives which is competitive with corporations with which the Company and its Participating Affiliates must compete for executive talent and to assist the Company and its Participating Affiliates in attracting and retaining executives who are important to their continued success.

The Plan was adopted as the Management Incentive Compensation Plan effective January 1, 2001. It was amended, effective January 1, 2009, to change its name to the Senior Management Incentive Compensation Plan. It affects the following employees:

(a) Those Employees who are subject to Section 16 of the Securities Exchange Act of 1934, as amended, and those Employees who are key officers or management Employees of the Company, a Subsidiary or an Affiliate who, in the opinion of the Committee, are in a position to have a direct and significant impact on achieving the Company's long-term objectives are eligible to participate in the Plan.

(b) The Committee may select such Employees of the Company or Participating Affiliate (individually or by position) for participation in the Plan upon such terms as it deems appropriate, due to the Employee's responsibilities and his/her opportunity to contribute substantially to the attainment of financial and operating objectives of the Company or Participating Affiliate. A determination of participation for a Plan Year shall be made no later than the beginning of that Plan Year. Provided, however, that an Employee whose duties and responsibilities change significantly during a Plan Year may be added or deleted as a Participant by the Committee. Provided further, the Committee may prorate the Incentive Award of any Participant if appropriate to reflect any such change in duties and responsibilities during a Plan Year.

In each Plan Year, an Award Fund is established equal to 2.5% of Net Income. No amounts are paid under the Plan for any Plan Year unless the Company has Net Income. However, the Committee shall have the right to decrease the amount of the Award Fund in any Plan Year.

The chief executive officer of the Company can receive an award not to exceed 10% of the maximum Award Fund for that Plan Year. All other Participants can receive an award not to exceed that amount which is 90% of the maximum Award Fund for that Plan Year divided by the number of Participants, other than the chief executive officer, in the Plan for that Plan Year.

The committee can pay the chief executive officer less than 10% of the maximum Award Fund, and pay to the other Participants, less than that amount which is 90% of the maximum Award Fund divided by the number of Participants, other than the chief executive officer, in the Plan for that Plan Year.

All such determinations, except in the case of the award for the chief executive officer, are made after considering the recommendations of the chief executive officer and such other matters as the Committee deems relevant. In making such determinations, the Committee may, in addition to achievement of short-term business objectives, take into account achievement by key executives of long-term goals of the Company. All awards are charged against the Award Fund and are made in one lump sum cash payment as soon as practicable after determined by the Committee.[20]

[20] Response to Discovery, OC-32.

Performance Goals

For each Plan Year, the performance goals of each Participant shall be approved within 90 days of the beginning of the Plan Year (or, for Participants joining the Plan during a Plan year, within 90 days of participation), by the CEO or such of his/her direct reports who is the Participant's manager. These performance goals shall be performance measures or objectives, whether quantitative or qualitative, which must be achieved in order to earn an Award under this Plan. The CEO or such direct report shall approve the specific targets for any such selected performance goals. These targets may be set at a specific level or may be expressed as relative to the comparable measure at comparison companies or to a defined index. Such performance goals shall include a corporate goal or goals related to the performance of the Company and may include (i) an employer goal or goals related to the performance of a Subsidiary or organizational business unit and (ii) an individual goal or goals related to the individual performance of the Participant in his/her position.

The CEO shall determine the substance and weighting of each goal of a Participant who is his/her direct report. The CEO may determine the substance and weighting of each of the goals of other Participants or may delegate the determination of the substance and weighting of these goals to such of his/her direct reports with respect to such person's relevant business units and direct reports.

The respective portions (corporate, business unit financial, business unit scorecard and individual) of each Participant's Target Incentive Amount shall then be multiplied by the Corporate Factor, the Business Unit Financial Factor, the Business Unit Scorecard Factor and the Individual Factor to determine the Participant's Incentive Award. For example, assume (i) a Target Incentive Amount of 40.0%, (ii) a Corporate Goal weighting of 35%, (iii) a Corporate Factor of 0.95, (iv) a Business Unit Financial Goal weighting of 35%, (v) a Business Unit Financial Factor of 1.25, (vi) a Business Unit Scorecard Goal weighting of 20%, (vii) a Business Unit Scorecard Factor of 0.75, (viii) a Strategic Goal weighting of 10% and (ix) a Strategic Factor of 1.1:

1. Corporate Portion = 0.95 x .35 x 40.0% = 13.30%
2. Financial Portion = 1.25 x .35 x 40.0% = 17.50%
3. Scorecard Portion = 0.75 x .20 x 40.0% = 6.0%
4. Strategic Portion = 1.10 x .10 x 40.0% = 4.4%

INCENTIVE AWARD = 13.30% + 17.50% + 6.0% + 4.4% = 41.2% x Salary
Notwithstanding anything contained in this Plan to the contrary, unless the CEO shall specifically so determine and the Committee affirm, a Participant's Final Incentive Award shall not exceed 2.0 times such Participant's Target Incentive Amount for the Plan Year to which it relates. Unless otherwise determined by the Committee or the CEO, the Employer Factor to be applied in determining a Participant's Final Incentive Award shall be that of the Subsidiary/ Business Unit/ Practice Area of which

the Participant was a member on the last day of (or, for terminated Participants eligible for Awards, on the last day of employment in) the Plan Year to which the Award relates.[21]

Performance Incentive Plan

Performance Incentive Plan For Certain Employees is designed to foster financial and operating objectives among employees. The purposes of this Plan are to foster attainment of the financial and operating objectives of the Company and its Subsidiaries by providing incentive to employees who contribute significantly to attainment of those objectives; to promote both individual and shared accountability for achieving annual performance and operating goals; to supplement salary and benefit programs so as to provide overall compensation for employees which is competitive with corporations with which the Company and its Subsidiaries must compete for talent; and to assist the Company and its Subsidiaries in attracting and retaining employees who are important to continued success.

Determination of Performance Goals

> *(a) Corporate Goals - Within 90 days of the beginning of each Plan Year, the CEO and PSEG's Organization and Compensation Committee shall approve such Corporate Goals as are deemed to be appropriate as well as the percentage of each Participant's Target Incentive Amount that shall be subject to the achievement of these Corporate Goals.*
>
> *(b) Business Unit Financial Goals. Within 90 days of the beginning of each Plan Year, each Employer shall approve such Business Unit Financial Goals as are deemed to be appropriate as well as the percentage of each Participant's Target Incentive Amount that shall be subject to the achievement of these Business Unit Financial Goals.*
>
> *(c) Business Unit Scorecard Goals - Within 90 days of the beginning of each Plan Year, each Business Unit leader shall establish from one or more Business Unit Scorecard Goals for his/her organization as well as the percentage of each Participant's Target Incentive Amount that shall be subject to the achievement of these Business Unit Scorecard Goals. The designation of business units and the adoption of Business Unit Scorecard Goals shall be subject to the approval of the Employer.*
>
> *(d) Strategic Goals - Within 90 days of the beginning of each Plan Year, each Business Unit leader shall establish one or more Strategic Goals for his/her organization as well as the percentage of each Participant's Target Incentive Amount that shall be subject to the achievement of these Business Unit Goals. The designation of business units and the adoption of Business Unit Goals shall be subject to the approval of the Employer.*
>
> *(e) Notwithstanding the foregoing, however, for any Plan Year, the Committee or the Chief Executive Officer may, as deemed to be appropriate, elect to adjust the applicable weightings of the Corporate Goals, the Business Unit Financial Goals, the Business Unit*

[21] Response to Discovery, OC-32.

Scorecard Goals and the Strategic Goals as part of the criteria for determining Awards for any Participant or group of Participants in this Plan.

Determination of Final Incentive Award

A Participant's Final Incentive Award will be determined as follows:

(a) Within 60 days of the end of each Plan Year, the Chief Executive Officer or the President of the Company shall certify the achievement of the Corporate Goals, the several Business Unit Financial Goals, the several Business Unit Scorecard Goals and the several Strategic Goals for the Plan Year.

(b) The result of such certifications shall be the Corporate Factor, the Business Unit Financial Factor, the Business Unit Scorecard Factor and the Strategic Factor, respectively.

(c) The respective portions (corporate, business unit financial, business unit scorecard and strategic) of each Participant's Target Incentive Amount shall then be multiplied by the Corporate Factor, the Business Unit Financial Factor, the Business Unit Scorecard Factor and the Strategic Factor to determine the Participant's Incentive Award. For example, assume (i) a Target Incentive Amount of 20.0%, (ii) a Corporate Goal weighting of 30%, (iii) a Corporate Factor of 0.95, (iv) a Business Unit Financial Goal weighting of 20%, (v) a Business Unit Financial Factor of 1.25, (vi) a Business Unit Scorecard Goal weighting of 40%, (vii) a Business Unit Scorecard Factor of 0.75, (viii) a Strategic Goal weighting of 10% and (ix) a Strategic Factor of 1.1:

1. *Corporate Portion = 0.95 x .30 x 20.0% = 5.70%*
2. *Financial Portion = 1.25 x .20 x 20.0% = 5.00%*
3. *Scorecard Portion = 0.75 x .40 x 20.0% = 6.00%*
4. *Strategic Portion = 1.10 x .10 x 20.0% = 2.20%*

INCENTIVE AWARD = 5.70% + 5.00% + 6.00% + 2.20% = 18.90% x Salary

A Participant’s Incentive Award is subject to further adjustment by application of an Individual Performance Modifier to determine Participant’s Final Incentive Award. The Individual Performance Modifier shall range from -50% to +50% based upon the recommendation of the Participant’s Business Unit Leader and subject to the approval of the President of the Participant’s Individual Employer to reflect such Participant’s contribution to the achievement of the Corporate, Financial, Scorecard and Strategic Goals for that Plan Year. Provided, however, that the total of all awards for a Business Unit that adjusts any individual’s Incentive Award by an Individual Performance Modifier shall not exceed the total of all awards for that Business Unit had no individual’s Incentive Award been adjusted pursuant to this Subsection.

Notwithstanding anything contained in this Plan to the contrary, a Participant's Final Incentive Award shall not exceed 2.25 times such Participant's Target Incentive Amount for the Plan Year to which it relates.[22]

Long-Term Incentive Plans

Public Service Enterprise Group Incorporated 2004 Long-Term Incentive Plan is designed to attract and retain best personnel is substantial positions. The purposes of the Plan are to promote the growth and profitability of the Company and its Subsidiaries by enabling them to attract and retain the best available personnel for positions of substantial responsibility; to motivate Participants, by means of appropriate incentives, to achieve long-range goals; to provide incentive compensation opportunities that are competitive with those of other similar companies; and to align Participants' interests with those of the Company's shareholders and thereby promote the long-term financial interest of the Company and its Subsidiaries, including the growth in value of the Company's equity and enhancement of long-term shareholder return.

The type and number of shares of Common Stock for which Awards may be granted under the Plan shall be determined as follows:

(A) The shares of Common Stock with respect to which Awards may be made under the Plan shall be shares authorized but unissued or currently held or shares reacquired by the Company and held as treasury shares, including shares purchased in the open market or in private transactions, all at the time of the Award.

(B) Subject to adjustment, the maximum number of shares of Common Stock available for issuance to Participants under the Plan (the "Share Authorization") shall be the 12,975,150 authorized shares of Common Stock not issued or subject to outstanding awards under the Prior Plans as of the Effective Date and (b) any shares of Common Stock subject to the 8,864,265 outstanding awards as of the Effective Date under the Prior Plans that on or after the Effective Date cease for any reason to be subject to such awards (other than by reason of exercise or settlement of the awards to the extent they are exercised for or settled in vested and non-forfeitable shares), up to an aggregate maximum of 20,000,000 shares of Common Stock**.**

(C) The following additional maximums are imposed under the Plan:

> *(1) The maximum number of shares of Common Stock that may be issued by Options intended to be Incentive Options shall be one million (1,000,000) shares.*
> *(2) The maximum number of shares of Common Stock that may be issued by Options that are not intended to be Incentive Options shall be, in the aggregate, fifty percent (50%) of the total shares reserved for Awards pursuant to paragraph (B) above.*

[22] Response to Discovery, OC-134.

(3) The maximum number of shares of Common Stock that may be issued in conjunction with Awards granted pursuant to Section 9 (relating to Other Stock Awards) and Section 10 (relating to Performance Shares) shall be, in the aggregate, fifty percent (50%) of the total shares reserved for Awards pursuant to paragraph (B) above.

(4) The maximum number of shares that may be covered by Awards granted to any one individual pursuant to this Plan shall be one million (1,000,000) shares during any 36 month period.

(5) For Cash Awards that are intended to be "performance-based compensation," the maximum Awards payable in cash to any one individual for a 36-month performance period shall not exceed ten million dollars ($10,000,000). Such maximum shall be reduced proportionately in the case of a performance period of less than 36 months and shall be increased proportionately for a performance period of longer than 36 months (but no further adjustment shall be made in the case of a performance period of greater than 60 months). If, after an amount has been earned with respect to a Cash Award, the delivery of such amount is, any additional amount attributable to earnings during the deferral period shall be disregarded for purposes of this limitation.

(D) Shares of Common Stock covered by an Award are only counted as used to the extent they are actually issued and delivered to a Participant, or, if permitted by the Committee, a Participant's designated transferee. Any shares of Common Stock related to Awards which terminate by expiration, forfeiture, cancellation, or otherwise without the issuance, are settled in cash in lieu of shares, or are exchanged with the Committee's permission, prior to the issuance of the Common Stock, for Awards not involving shares of Common Stock, shall be available again for grant under the Plan. Moreover, if the Exercise Price of any Option granted under the Plan or the tax withholding requirements with respect to any Award granted under the Plan are satisfied by tendering shares of Common Stock to the Company (by either actual delivery or by attestation), or if an SAR is exercised, only the number of shares of Common Stock issued, net of the shares tendered, if any, will be deemed delivered for purposes of determining the maximum number of shares of Common Stock available for delivery under the Plan.

The Committee has full and complete authority, in its discretion, subject to the provisions of the Plan, to grant Awards to Participants consisting of Options, Stock Appreciation Rights, Restricted Stock, Stock Units, Performance Shares, Cash Awards or any combination thereof, subject to such terms and conditions as the Committee deems appropriate. Awards may be granted singly, in combination or in tandem so that the settlement or payment of one automatically reduces or cancels the other. Awards may also be made in combination or in tandem with, in replacement of, as alternatives to, or as the payment form for, grants or rights under any other compensation plan of the Company or any Subsidiary, including the plan of any acquired entity. The Committee may permit or require that any Award be prorated to the date of any termination of employment.

Performance Awards

The Committee may make Awards consisting of Performance Shares, containing such terms and conditions, and subject to such restrictions and contingencies as the Committee shall determine, subject to the provisions of the Plan. Performance Awards shall be conditioned on the achievement of Performance Goals, based on one or more Performance Measures, as determined by the Committee, over a performance period (not less than one year) prescribed by the Committee. For Awards intended to be "performance-based compensation", the grant of the Awards and the performance goals shall be made during the period required under Code section 162(m). In the event that a Change in Control occurs after a Performance Award has been granted but before completion of the performance period, a pro rata portion of such Award shall become payable as of the date of the Change in Control to the extent otherwise earned on the basis of achievement of the pro rata portion of the Performance Goals relating to the portion of the performance period completed as of the date of the Change in Control. Unless otherwise directed by the Committee, as a condition of receiving an Award consisting of Performance Shares, a Participant must waive in writing the right to make an election under Section 83(b) of the Code to report the value of the Performance Shares as income on the Date of Grant.

The only significant change to PSEG's executive compensation program since January 1, 2007 involved the separation of the Management Incentive Compensation Plan (annual incentive compensation) (MICP) into two plans, the MICP and the Senior Management Incentive Compensation Plan (SMICP), and the modification of the performance measures under each plan, which became effective January 1, 2009. The change impacted the calculation of annual awards by identifying four individual incentive components that are additive with respect to determining a payout under the new incentive program. In addition, the 2009 change included the introduction of balanced scorecards as one of the four compensation design components for compensation purposes. The scorecard includes such measures as electric system reliability, a number of customer service related goals and other employee, operational and cost measures. Financial and operating results are also components of the overall incentive program. The four incentive components are weighted differently and set primarily by organizational level. Further, certain performance measures for performance shares under the long-term equity compensation program were revised to add Return on Invested Capital as a performance measure.[23] These changes are shown schematically in Tables 23-16 and 23-17 below.

[23] Response to Discovery, OC-134.

[Begin Confidential]

Table 23-1[illegible] – Overview – Incentive Plans – What's Changed for 2009

[redacted]

Table 23-17 – Weighting for 2009 Annual Incentives by Goal Component, by Org. Level

[redacted]

[End Confidential]

Benefits Programs

PSEG Benefits Programs

The large number and wide variety of PSEG benefits programs are difficult to follow and presumably to administer. The company could benefit from a summary document of these various programs by type, eligible employee, and benefit provided. A list the various benefits programs is provided below:

- Cafeteria Plan of Medical, Dental, Disability, and Other Benefits
  - Selectline (Non-Represented)
  - Choices (Represented)
  - Benefits 2000 Non-Represented
  - Benefits 2000 Represented
- Adoption Assistance Plan
- Group Term Life Insurance Plan for Non-Represented Employees
- Group Term Life Insurance Plan for Represented Employees[24]
- Post Retirement Supplemental Health Benefits Plan (VEBA)
- Travel Accident Insurance Plan
- Short Term Disability Plans:

[24] This document indicates PSEG Services Corporation but the plan is the same for all groups.

  - Short Term Disability Benefits Program for Choices and Selectline Participants
  - Short Term Disability Benefits Program for Benefits 2000 Employees
- Defined Contribution Benefit Plans:
  - Thrift and Tax Deferred Savings Plans (Non-Represented)
  - Employee Savings Plan (Represented)
- Separation Allowance Benefits Plans:
  - Separation Allowance Benefits Plan for Non-Represented Employees
  - Separation Allowance Benefits Plan for Represented Employees
- Defined Benefit Pension plans:
  - Pension Plan (Final Average Pay) for Selectline and Choices
  - Cash Balance Plan for Non Represented Employees
  - Cash Balance Plan for Represented Employees
- Non-Qualified Benefit Plans
  - Deferred Compensation Plan For Certain Employees
  - Retirement Income Reinstatement Plan
  - Mid-Career Hire Supplemental Retirement Income Plan
  - Limited Supplemental Benefits Plan
- Retired Employees Benefit Plan Documents
  - Medical Benefits Plan for Retired Employees
  - Dental Benefits Plan for Retired Employees
  - Group Term Life Insurance for Retired Employees[25]

Comparison to Peers

Despite the number of plans and the benefits provided, PSEG compares favorably with its Peers regarding the cost of its benefits programs. The Hewitt Benefit Index Reports for New Hires (Benefits 2000) and Grandfathered Employees (Legacy Benefits Plan) compare PSEG to Industry Peers. Both reports are as of the first quarter 2009. In the study, Public Service Enterprise Group's grandfathered salaried employee benefit program is compared to a norm of the grandfathered salaried benefit programs of the following 15 utility companies chosen by PSEG:

- American Electric Power Company, Inc.
- Consolidated Edison Company of New York, Inc.
- Constellation Energy Group
- Dominion Resources, Inc.
- DTE Energy Company
- Duke Energy Corporation
- Edison International
- Entergy Corporation
- Exelon Corporation
- FirstEnergy Corp.

[25] Response to Discovery, OC-144.

- FPL Group Inc.
- Pacific Gas & Electric Company
- Progress Energy, Inc.
- Sempra Energy
- Southern Company

Benefit Areas Included. The benefits included are those which have substantial value and which can be fairly compared. Additional forms of direct compensation and government-required programs are not included. The benefits are grouped as shown below. Benefits not included in this index are severance pay, supplemental unemployment benefits, travel accident, extra individual accident coverage, tuition refund, matching donations, work and family benefits, and government-required programs.

- Retirement
  - Primary
  - Matched Savings
- Death
- Disability
- Health Care
- Time off with Pay

As shown below, PSEG ranks at the median of its 15 peers in terms of the total value of all benefits and slightly above the middle of its 15 peers in terms of the employer-paid value of all benefits for grandfathered employees.[26]

[26] Response to Discovery, OC-1307.

[Begin Confidential]

Table 23-18 - Public Service Enterprise Group Grandfathered Programs as of February 2009

[redacted]

Table 23-1[illegible] - Public Service Enterprise Group New Hire Programs as of February 2009

[redacted]

[End Confidential]

24. PRODUCTIVITY AND UTILIZATION LEVEL OF THE WORKFORCE

Introduction

This Chapter addresses the following human resources functions:

- Productivity Analysis
- Staffing Levels
- Human Resources Strategy

PSEG's other human resources functions are addressed in Chapters 23, 25, and 26.

Summary of Findings

1. PSE&G utilizes several mechanisms to manage employee productivity.
2. HR plays a key role in the strategic direction of the company.
3. The Workforce Planning Process is well-defined and effective.

Recommendations

1. It appears that spans of control can be improved by decreasing some, but mostly, by increasing many.

Employee Productivity

PSE&G Mechanisms to Manage Employee Productivity

PSE&G utilizes several mechanisms to manage employee productivity. PSE&G Electric Delivery focuses on overall efficiency in terms of the strategy achieving 1st decile safety results and at least first quartile reliability and operational results while meeting financial requirements. The approach to improving employee productivity is to (1) use an Asset Management philosophy to prioritize the work so that only the highest-value work mix is undertaken; (2) use the Operational Excellence Model to identify and improve Critical Functions, Processes and Procedures; and (3) use the Balanced Scorecard to assess results and identify areas needing improvement. Continuous improvement is embedded in the goals and scorecards, and is driven through various initiatives that include balanced scorecard metrics, operational / process efficiency drivers including the use of new technologies and materials, benchmarking, and use of available work management systems. Cross functional teams composed of line management, bargaining unit representatives, subject matter experts and support personnel, as needed, meet regularly to review practices, procedures, material and equipment, share proven practices and promote consistency across the organization.

The Electric Delivery Balanced Scorecard contains measures linked to employee productivity with targets established for continuous improvement. The specific metrics include staffing, overtime, availability, and 'hours to work' which is an aggregate indicator of hours worked on a representative mix of specific tasks. The Work Management Systems capture data on a daily basis and provide daily, weekly and monthly reporting which is used to monitor and develop initiatives to drive improvement to achieve scorecard targets. Reports are shared with PSE&G associates by management and the unions on an ongoing basis so associates know of gaps between target and actual performance. Evolving technology in the form of new tools, equipment, materials, and process are deployed to provide associates the most safe and efficient work methods.[1]

PSE&G Gas Delivery's approach to improving employee productivity is driven through various initiatives that include balanced scorecard measures, operational / process efficiency drivers including the use of new technologies and materials, benchmarking, and use of available work management systems. Cross functional teams within Gas Delivery for Construction Efficiency and Appliance Service Efficiency comprised of line management, bargaining unit representatives, subject matter experts and support personnel meet regularly to review practices, procedures, material and equipment, share proven practices and promote consistency across the organization.

The Gas Delivery Balanced Scorecard contains measures linked to employee productivity with targets established for continuous improvement. Work Management Systems capture data on a daily basis and provide daily, weekly and monthly reporting which the Efficiency Teams monitor and use to develop initiatives to drive improvement to achieve scorecard targets. Reports are shared with PSE&G associates by management and the unions on an ongoing basis so associates know of gaps between target and actual performance. Evolving technology in the form of new tools, equipment, materials, and processes are deployed to provide associates with the most safe and efficient work methods in Gas Distribution and Appliance Service.

The Gas Delivery Training Committees, comprised of management and the union personnel, continuously work to identify workforce training needs and play a key role in developing new training curriculums consistent with evolving business requirements.[2]

PSE&G Customer Operation's approach to improving employee productivity includes utilizing the balanced scorecard, performance management process, operational efficiency initiatives, process improvement and the use of new technology. Cross functional teams are also established within the organization that focus on making process improvements that are aligned with the balanced scorecard.

During the business planning process, goals are established to support reaching 1st decile safety results and achievement of at least first quartile operational results based on benchmarking best in class businesses. Specific initiatives are also established to support accomplishment of employee productivity targets.

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[1] Response to Discovery, OC-150
[2] Response to Discovery, OC-150

The Customer Operations Balanced Scorecard contains measures linked to employee productivity with targets established for continuous improvement. Specific metrics include safety, availability, staffing levels, training and employee development and employee overtime. The PSEG Services Corporation Scorecard contains measures linked to employee productivity with targets established for top quartile performance and/or continuous improvement. The balanced scorecard is used to assess results and identify areas needing improvement. Continuous improvement is driven by initiatives and/or projects designed to improve metric performance. The specific metrics include succession planning, employee development, and availability. The succession planning goal measures how robust succession plans are, and encourages dialogue regarding development activities for succession candidates. The employee development goal drives participation and completion of development plans to enhance skills. The Services Corporation tracks data related to the achievement of employee development goals, and results are published in relationship to targets on a quarterly basis. These results are used to monitor and develop initiatives to drive improvement to achieve scorecard targets. Availability drives productivity by ensuring that employees are returned to work and productivity as soon as medically recommended.[3]

Our review of the elements of the productivity management system included sample Balance Scorecards, Operational Excellence Models and Work Management Systems. We found them to be in place and effective.

HR Role in Strategic Direction of the Company

[Begin Confidential]

[3] Response to Discovery, OC-150

4 Response to Discovery, OC-995
5 Response to Discovery, OC-995

[End Confidential]

We take no issue with HR's alignment of its strategic priorities with those PSEG's strategy.

[6] Response to Discovery, OC-995

Table 24-1 - The Workforce Planning Process is well-defined and effective

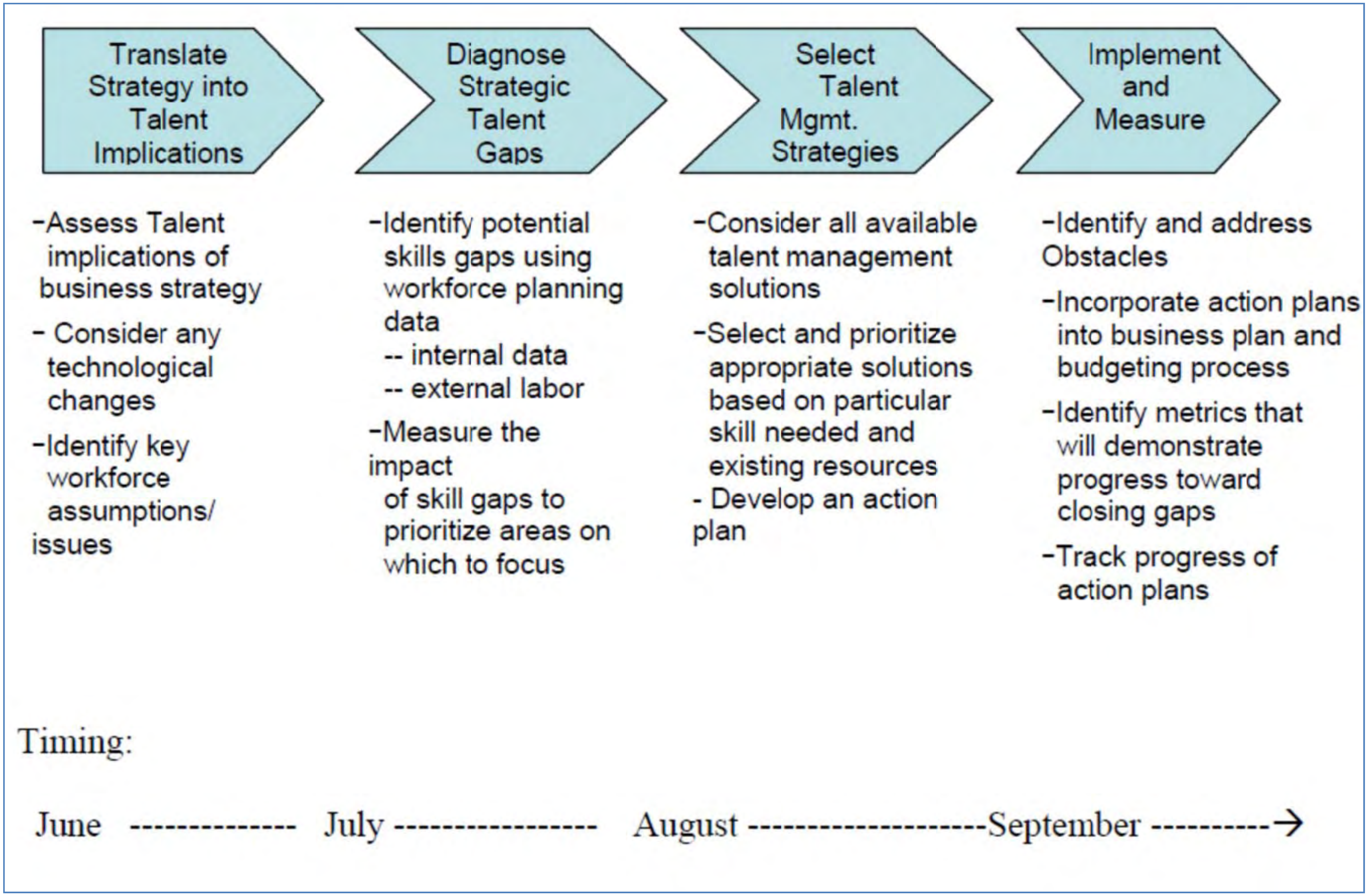

Table 24-1 above is a schematic of the workforce planning process.[7] Before beginning the workforce planning process, the main drivers for workforce planning are reviewed. These drivers set the context for everything that is considered. These four main drivers are:

Organization/ Departmental Direction. This includes strategic plans, budget forecasts, new technology, working practices and organization culture. Internal Labor: This includes a review and analysis of internal labor and includes, but is not limited to: retirement eligibility by job classification/ critical positions projected out for 10 years, projected retirement based on historical trending projected out for 10 years, and market pull analysis for previous 10 years. This analysis is done by department and by position, with a specific focus on critical positions, especially those positions that have a long lead time for development. Critical positions are defined as those positions that have a direct impact on business strategy implementation/ business performance. Typically, the incumbents have a specialized skill or knowledge that require a long lead time for training. Career paths are also analyzed to determined how employees move through the organization and the impact that this may have when combined with all other information. External labor: Review of supply data by review EMSI data base by occupations. In addition, have further discussion with managers and staffing/ recruiting to provide insights into labor market supply risks that might impact our ability to hire.

Business Change: Technological changes are leading to changes in the way work is done, and the skills needed in the workforce. What changes to competencies or skills for positions are needed currently or will be needed in the future.

Diagnosing Strategic Talent Gap. It is important to identify all factors that could influence future demand for products and services, as well as the competencies of the internal and external supply of labor. There are four data points that provide key workforce information needs. They include: Organization direction and environmental factors (demand analysis); internal and external labor (supply analysis).

Suggested checklist for Organization Direction:

- Strategic Plan/ Business priorities
- Internal or External data that could affect business outcomes (e.g. INPO/ BPU)
- Five year Budget
- Plans for new technology
- Employee survey results
- Organizational culture
- Changing skills in mission critical positions
- Events that may influence turnover
- Environmental Factors
- Changes in economic forecast

[7] Response to Discovery, OC-155

Suggested checklist for internal labor profile information: (See appendix A)

- Identification of critical positions
- Retirement eligibility for all positions – 10 years
- Retirement eligibility for critical positions – 10 years
- Retirement projections for all positions – 10 years
- Retirement projections for critical positions – 10 years
- Market Pull Analysis for critical positions for previous 10 years[8]
- Market Pull Analysis for all positions for previous 10 years[9]
- Process/ Program Risk Ranking Assessment[10]
- Single Point Vulnerability Assessment[11]
- Skill deficits that are evident today
- Robustness of the succession plan (two replacements deep for all critical positions)
- External labor profile information
    - Labor trends for all positions
    - Labor trends for critical positions
    - Trends in student graduation rates at university / colleges where we recruit from
    - Acceptance rates

Gap Analysis. One of the most useful outcomes of this process is the identification of potential workforce problems or issues facing the organization; identification of the gaps that need to be filled to meet the future workforce demands and to insure a sufficient pipeline of talent. The gap analysis should consider the following questions:

- What attrition and retirement can be expected over the next ten years?
- What types of positions will need to be filled and by when?
- How long is the lead time needed for training for these positions?
- What are the succession planning implications?
- Any redeployment concerns or issues with current staff?
- How can training help?
- What are the potential sources of staffing for these positions?
- Are the positions hard to fill?

There are several factors that may impact the success of workforce planning initiatives, and must be considered when conducting the gap analysis. Although workforces are aging, organization cannot predict with certainty when employees will actually retire due to factors that may delay retirement. Projected retirements are based on historical analysis, however, factors such as health care costs, and economic environment may impact when employees will actually retire. Therefore, there may be a need to determine a best case and worst case scenario when developing action plans. One other factor to

[8] This term refers to the historical statistical analysis by year identifying terminations by critical position, other than for retirement reasons. Critical position is defined as a position that has a long lead time for training and/or qualification.

[9] This term refers to the historical statistical analysis by year identifying terminations of employees leaving PSEG, other than for retirement reasons.

[10] This term refers to a process that ranks the potential business impact of the loss of critical knowledge in the organization.

[11] This term refers to an assessment that determines if a critical process or business task is only known by a single person.

consider is the inability of organizations to identify, prioritize and implement action plans. Effective prioritization to ensure the most critical gaps must be addressed first. A commitment from senior management to implement the action plans is also critical for success. One way to accomplish this is to ensure that the actions plans are incorporated into the business planning and budgeting processes.

Select and implement gap closure/ talent management strategies. After analyzing, forecasting and planning, an implementation plan must be put in place to carry out the planned activities included in the workforce plan. This is a process of using all the information gathered up to this point in developing a plan to close the gaps. There are a few critical components to be considered prior to implementation. They include:

- Ensuring organization buy-in and support - Allocating necessary resources to carry out the plan
- Clarifying roles and responsibilities in implementing action plans
- Establishing milestones
- Determining performance measures
- Feasibility of implementation

Monitoring and Evaluating the Action Plans. Ongoing tracking of the process against action plan objectives is critical for success. In addition, evaluation of workforce plan is imperative in determining if the action plans are addressing the identified gaps. Below are some questions that should be asked to determine effectiveness of the strategies:

- Are there any needed adjustments to the plan?
- Were the plans completed?
- Are the assumptions of the need and supply analysis still valid?
- Have there been any new workforce and / or organizational issues that have occurred?

Action plans should be integrated into budget plans and future year's business planning process. Updates for the action plans should be provided quarterly to senior management.

Staffing Levels and Spans of Control

It appears that spans of control can be improved by decreasing some, but mostly, by increasing many. The rationale for the level of staffing is based upon business needs, both historical and projected. Each year during the business planning process, each PSEG company reviews its current staffing levels for both Management, Administrative, Supervisory, and Technical (MAST) and Union employees and determines if these levels are sufficient to meet their specific business operating needs. Staffing levels are planned during the annual business planning process. Staffing levels, both permanent, temporary and seasonal, are based on such things as projects, outages, safety, reliability, and other unique business requirements.[12]

[12] Response to Discovery, OC-156

Based upon the organization chart dated 11/9/2009, for the most part, the number of direct reports appears on the high side of normal:

- PSE&G -8 direct report units
- Customer Operations--8
- Southern Division Gas--10
- Electric Operations—7
- VP Finance – PSE&G--9[13]

Though the number of direct reports in some cases appears much too small:

- Customer Relations and Community Relations---2
- Customer Operations staff--3
- Billing and Revenue Operations-3
- Billing Division and Technical Services--2
- Trn Plt and Engineering—Svc and Support--2
- Southern Division Engineering--2
- Metropolitan Overhead Construction--2
- Metropolitan Operations and Resources--1

And others appear much too large:

- Customer Service Centers--16[14]

[13] Response to Discovery, OC-1270 and OC-1379. The Corporate Rate Counsel function was subsequently (in October 2010) moved to the Service Corporation and split between the Law Department and Finance.

[14] Response to Discovery, OC-156

Appendix A - Workforce Planning Guide 24-1

No.	Report Name	Description	Timeframe	Detailed Breakdown
1.	Current headcount vs. Approved headcount	Critical position analysis showing actual headcount vs. approved headcount	Monthly	1. Critical positions for Salem, Hope Creek, Common and Nuclear and PSE&G
2.	Current headcount (qualified and non qualified) vs. approved headcount	Same report # 1 with actual headcount indicating timing when incumbent becomes fully qualified for critical position	Quarterly	1. Critical position for Salem, Hope Creek, Common and Nuclear and PSE&G
3	Total Attrition	Breakdown of attrition by all categories (both voluntary and involuntary attrition)	Yearly – past 10 years (every July)	1. PSEG 2. PSE&G 3. Services 4. Power 5. Nuclear 6. Fossil
4	Voluntary turnover – excludes retirements (Market Pull Analysis)	Includes breakdown of resignations only (to be used for KT&R process risk ranking process)	Yearly – past 10 years (every Mar.)	1. PSEG 2. Nuclear by position 3. PSE&G
5	Average age of workforce by year	Average age for past 8 years	Yearly (every July)	1. Total 2. Union & Mast; 3. PSEG 4. Services 5. Power/ Nuclear & Fossil 6. PSE&G
6	Average age groupings	Breakdown by age categories/ groupings	Yearly (every July)	1. Total 2. Union & Mast; 3. PSEG 4.Services 5. Power/ Nuclear & Fossil 6. PSE&G
7	Years of Service distribution	Breakdown by years of service groupings	Yearly	1. Total 2. Union & Mast; 3. PSEG 4. Services 5. Power/ Nuclear & Fossil 6.PSE&G
8	Retirement eligibility	Retirement eligibility over next 10 years – early retirement/ most likely to retire (age 58) and late retirement	May and December	1. Total 2. Union & Mast; 3. PSEG, 4. Power/ Nuclear & Fossil 5. Nuclear critical positions 6. PSE&G

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25. Development, Training, Evaluation, and HR Ability to Access Personnel Information and Perform Assigned Duties

Introduction

This Chapter addresses the following human resources function:

- Leadership and Employee Development
- Training
- Performance Evaluation
- Recruitment and Hiring

PSEG's other human resources functions are addressed in Chapters 23, 24, and 26.

Summary of Findings

1. PSEG has a very structured process for recruiting and hiring its employees.
2. PSEG has effective training, development, and evaluation techniques. They are used in a variety of training programs for employees at all levels.
3. Access to Personnel information is adequate through the use of SAP and Empower.
4. Functional Areas of Human Resource Management seem adequate, but there are some areas of concern.

Recommendations

1. In order to expand its recruitment efforts PSEG should continue and increase its outreach to students.
2. PSEG should also make greater use of technology in its recruitment efforts.
3. In addition to its current practice to support employee development, PSEG should consider establishing mentorship programs for high potential employees.
4. PSEG should develop an organizational manual and develop position descriptions for all significant positions.

Recruitment and Hiring

PSEG has a very structured process for recruiting and hiring its employees. PSEG's practices related to recruiting and hiring staff are well documented and clearly laid out in its Human Resources Practices #710-2 and #710-2-1.

The Company states that Human Resources' approach to staffing ensures that "we select the best candidate for the job, through fair and consistent processes". PSEG's Staffing Practice describes the procedures used by candidates to express an interest in an open position. The Staffing Practice also describes the process for accommodations, the use of search firms, advertising for positions, job offers and pre-placement physicals and drug screenings. The PSEG Hire process describes the steps that must be taken to begin the staffing process. It details a "step format" as to how to initiate a new posting and the selection process. Human Resources Practice #710-2 indicates that procedures are designed to ensure cost efficiency, fairness, and effectiveness in identifying qualified candidates for job vacancies.

PSEG receives at least 20,000 resumes each year. The number of resumes received often exceeds that amount. The procedures require that external applicants must submit resumes through CareerLink on www.pseg.com. Internal candidates bid for jobs through CareerLink on the PSEG Intranet[1].

The Company believes that its practices ensure that it selects the best candidate for job, through fair and consistent processes. The Director of Talent Acquisition advised that there are sometimes complaints from hiring managers that the process is too long and that you can't just hire the person that you know. There are basic requirements that must be met. There are metrics used (for example, Days to accept). The Company looks at its peers. It uses Saratoga Studies (an affiliate of PricewaterhouseCoopers) to compare PSEG against other companies. The Director of Talent Acquisition stated that PSEG does well when compared to other companies on Saratoga. The drawback to the process is that it takes time, such as the time required for background checks. Human Resources reviews the processes used by Talent Acquisitions. The processes used by Performance and Development are also reviewed. The processes used are reviewed at least once a year. Additionally, the Business Operations Group has the responsibility for looking at the processes used on an annual basis.[2]

The Company believes the process used for recruitment and hiring helps selects the best candidate for the job—compliant with Office of Federal Contract Compliance Programs (OFCCP). It complies with government requirements. It ensures that you don't just hire a friend. The average number of days to accept a position is 45 days. In comparison to its peers, it is very good—better than the median and close to the top quartile.

The responsible manager or supervisor looks to be sure that processes used in recruitment and selection are consistent with the outside world, goals and accomplishments. The process owner also tries to make the processes more efficient. The Business Operations Group oversees the Operational Excellence Model. In that connection, it reminds the process owner to review their policies and procedures and to make sure that all steps are taken.[3]

[1] Response to Discovery, OC-143.
[2] Interview on April 14, 2010 with Vincent Labbate, Director Performance and Development, Randi Casey, Director Talent Acquisition and Tom Frye, Director, Human Resources, PSE&G.
[3] Interview on April 14, 2010 with Vincent Labbate, Director Performance and Development, Randi Casey, Director Talent Acquisition and Tom Frye, Director of Human Resources, PSE&G.

Recommendations

1. In order to expand its recruitment efforts PSEG should continue and increase its outreach to students in community colleges and four year colleges regarding employment opportunities at PSE&G and it should also participate in job fairs.

2. PSEG should also make greater use of technology in its recruitment efforts and should continue to use LinkedIn and other technology to increase public awareness of job opportunities at PSEG.

PSE&G Training, Development, and Evaluation Techniques

PSE&G has effective training, development, and evaluation techniques. They are used in a variety of training programs for employees at all levels. PSE&G's technical and safety training is managed by the Utility Operations Support Department. The Technical Training Department of Utility Operations Support, is a permanently assigned group of 40 individuals that plan for and deliver all technical and safety training for PSE&G. In addition, individual locations provide "on the job" training as support to the formal program, to maintain and develop skills in a cost effective manner while allowing for maximum scheduling flexibility.4

As noted above, the Technical Training Department is comprised of a staff of forty employees, including a small administrative and facilities maintenance group. Training takes place in two state-of-the-art technical training complexes in Edison, New Jersey. One, the Edison Training and Development Center, also doubles as a conferencing facility. The other, the Gas Learning Center, is used predominantly for Appliance Services courses. PSE&G tracks the number of students that attend the courses.

Additionally, enhancement and refresher training is provided to associates in journeyman classifications in a formalized manner at the training facility and at the operating field.

The Technical Training Department provides technical training to over 6,000 employees of its Electric Delivery, Gas Delivery and Customer Operations. The core curriculum for technical training is principally contractually negotiated apprentice programs for craft employees, running the gamut of nomenclatures such as lineman/linewomen, street mechanic, division mechanic, substation operator, appliance service apprentice, service dispatcher, meter technician, equipment operator, etc.[5]

Training is delivered through various means, traditional instructor/student, face to face in the classroom, using a staff of subject matter experts, full time instructors, operational line of business experts acting as instructor adjuncts; contract adjuncts and out-sourced training. Alternative computer based training supplements the classroom instruction. Offerings in these areas are programmed to meet or exceed all legal and regulatory requirements and standards, and in accordance with all Union agreements.

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[4] Interview on April 14, 2010 with Vincent Labbate, Director Performance and Development, Randi Casey, Director Talent Acquisition and Tom Frye, Director of Human Resources, PSE&G).

[5] Response to Discovery, OC-145.

Since the training in all these areas is 'hands-on', every effort is made to utilize experienced in-house PSE&G trainers. Occasionally, a need arises to bring in special expertise, in which case a 'train the trainer' approach is generally preferred.

PSE&G Customer Operations employees get health and safety training as part of their initial employment technical training. All training is conducted by certified and trained PSE&G instructors. Training is typically delivered, as required by regulation or by company policy, in classrooms or on-line and can be a single session or initial plus annual refresher. Decisions for new training are based on needs assessment or hazard analysis.

All new employees receive their training through subject matter experts on the job or at the company's technical training facility. Entry level positions in Customer Operations are typically in meter reading or the inquiry center, and training for those positions is determined by the skills needed. Health and Safety training is incorporated in the technical training and is based on the hazards faced.[6]

PSE&G has apprentice programs which it states are designed to incrementally build the skill levels of the apprentice. The initial training programs cover basic tools, equipment and work practices focusing on safety and personal protective equipment required to perform the tasks. Subsequent training programs raise the level of skills and knowledge that is required to progress. PSE&G has a structured program for employees who attend the apprentice program. If an employee satisfactorily completes the program, they progress to the journeyman classification. Recruitment is done in-house following a contractually agreed upon posting process with the unions. When there is a lack of interest from existing employees, the Company will post positions externally.

All training programs for represented employees are contractually agreed upon with the Unions. The time and duration of a program is also covered by union contracts. The material provided in these programs is developed with input from training committees that provide an avenue for management and represented employees to determine the material to be covered.

From time to time, it is necessary to bring in some special expertise, in such cases, a 'train the trainer' approach is generally preferred. The need to hire an outside vendor is based on the expertise required. One example is the training required to obtain certification for a license to operate hydraulic cranes. The training is very intensive and requires an individual with experience and expertise to provide the in depth knowledge needed to pass the written and practical test required. It is noted that since the training is delivered to a very limited number of crane operators and is only required once for the individual, it is far more cost effective to hire an outside Certified Instructor to provide the program.[7]

[6] Response to Discovery, OC-145.
[7] Response to Discovery, OC-1316.

The training in all areas is 'hands-on' and specific to PSE&G requirements, practices and procedures. Accordingly, training is kept physically in-house and every effort is made to utilize experienced in-house PSE&G trainers. It is noted that when the need does arise the cost differential is generally $500 per day for outside versus internal instructors.

Training records for represented employees are maintained in SAP. A software program called "Perception" is utilized to evaluate the effectiveness of the programs. The Company notes:

> *The use of Perception provides us with a means to evaluate the results of quizzes and tests that an individual takes during the course of the training. This software allows us to evaluate whether the individual is retaining the instruction given and also whether the material is being covered effectively during a program. The analysis… enable us to continuously investigate and improve our test items and answer choices to measure important knowledge and skills. Our test developers can analyze which items are working well, which items need minor improvements, and which items should be removed from the test*[8].

Professional and management training is provided to PSE&G employees by either in-house resources or external resources. The decision is generally based on resource and expertise availability, with a strong view towards cost management. This has included "train the trainer" programs so that skills can be brought into organization and used as needed. Training and development needs can be driven through either regulatory requirements or identified in individual "Performance Partnerships" through the development planning process which identifies training needs specific to individual employees.

The primary management training programs used by the entire corporation, including PSE&G are the "Academy" programs. The leadership development academies are focused on 2 populations: First Line Supervisors (or the equivalent title) in PSE&G, as well as in, PSEG Power, PSEG Services Corp and middle managers or employees whose potential, aspiration and development plans reflect an inclusion toward leadership.

The leadership development academies consist of the Supervisory Academy which is focused on individuals that supervise either bargaining unit or MAST employees and the Leadership Academy which is focused on managers. The Leadership Academy is focused on providing managers with a broader business vision and specific tools to improve their management skills and work group results. This program uses both internal and external resources.[9]

There are 25 employees in each supervisory academy. About 140 employees receive training in academies each year. The academy training for first line supervisors is ongoing. The Company's target is

[8] Response to Discovery, OC-1316.
[9] Response to Discovery, OC-1316.

to train 100% of its first line supervisors. There were four academies conducted in 2008 and four conducted in 2009. The program was piloted in 2007.

The Supervisory Academy is built around the PSEG Strategic Business Model which emphasizes Operational Excellence, Financial Strength and Disciplined Investment. The participants are selected by their managers using the criteria above and prepared prior to attending by creating development plans with their managers and undergoing a rigorous behavioral assessment to help them understand their leadership style. The participants spend 3 weeks learning supervisory leadership skills via a number of modules and developing a learning partnership with each other. A class sponsor (usually a vice president) creates a class project with the objective of having participants focus on a specific issue of Enterprise-wide importance and dimensions. The class project is intended to foster teamwork, individual leadership and commitment to excellence. The learning modules include: Responsibility and Accountability, PSEG Vision & Values, Decision Making, Effective Communication, Active Listening, Giving & Receiving Feedback, Understanding Human Behavior, Emotional Intelligence, Self Management, Group Dynamics, Developing Self & Others, Creating a Development Partnership, Leading in a Diverse Environment, Situational Leadership, Project Management, Managing Agreement, Competition and Collaboration, Leading Teams, Motivation, Rewards and Recognition, Managing Conflict, Managing Change, Leading Effective Work Meetings, Action Planning, Presentation Skills, and Finance. In addition, there are a number of PSEG-specific topics covered such as performance management, safety, disability management, human performance awareness, EEO/affirmative action, and employee assistance. There is a fourth week of training that comprises the program primarily for training in Management Action Response Checklist (MARC) and Collective Bargaining Agreements (CBA) and the newly developed bargaining unit performance management process. Supervisors who do not have responsibility for union employees are not required to attend the 4th week of training.

It is noted that participants in the Supervisory Academy, in addition to the class project, have an obligation to their manager and the Academy program manager to provide learning application updates, 3 months, 6 months and 9 months after the program to demonstrate sustained learning. After the formal reporting process ceases, the manager's obligation to continue the learning process becomes part of the employee's performance partnership process.[10]

The Leadership Academy is built around the four leadership competencies which comprise the PSEG leadership module: Real Leadership Presence; Thought Leadership; Attracting and Development Talent; and Achieving Exceptional Results. The four cornerstone leadership competencies are presented in a real-life leadership context by four executive leaders of PSEG usually one of whom is the CEO. The 5 day residential program is preceded by modules on presentation skills and finance which add an additional 4 days to the schedule. The Leadership Academy emphasizes understanding one's own leadership strengths and development needs and utilizes an advanced personality assessment tool (Birkman) to provide high value input to that part of the learning process.

[10] Response to Discovery, OC-145.

Participants in the Leadership Academy are chosen by their managers (usually directors) with the concurrence of the department Vice President and represent employees who currently are or are soon to hold managerial responsibilities and demonstrated to at least fully meet expectations performance, leadership inclination and potential.[11]

The Leadership Academy is also preceded by development planning between the participant and manager which result in specific learning goals to be achieved and a real time "action learning" project which is designed to address and solve a real current management problem which does not yet have a solution. The "action learning" process is taught as part of the Leadership Academy.

In addition, there are a number of learning modules that comprise the Leadership Academy curriculum, including: Emotional Intelligence, Creating Growth, Personal Accountability, Managing from the Middle, Growth vs Change, Executing Strategy, Fostering Innovation, Leading with Integrity, Creating Trust & Respect, Coaching, Delegating, Managing Teams, Managing Conflict, Negotiating Skills, Crucial Confrontations, Effective Team Performance, Safety, and Leveraging Diversity.

The program utilizes case analyses, action learning and a variety of interactive learning and teaching techniques. The Action Learning Project is an on-going endeavor and is reported on 3-6 months after the Academy concludes.[12]

PSEG cost per student day for the Supervisory Academy is approximately $405 and at top quartile compared to external courses (approximately $405). Leadership Academy cost per student is approximately $955 which is somewhat higher than top quartile ($926) but more economical than median ($1,320).[13]

PSE&G also has available a variety of learning "toolkits" which are usually developed in-house and provide a basis for self-instruction. The toolkits are used from time to time as the basis of an in-house workshop by in-house resources. These workshops cover a range of topics, including but not limited to, performance management processes and techniques for performance evaluation discussion between manager and employee, providing feedback and coaching.[14]

PSE&G employees may also attend a variety of skills training courses presented by external resources, usually at community colleges, under a training grant provided by the New Jersey Utilities Association. There are no costs associated with attending these courses. The courses cover such skill sets as business communications, writing skills, using EXCEL spreadsheets, preparing PowerPoint presentations and other computer-related skills. These courses would otherwise cost PSEG approximately $175,000 over a two year period.

[11] Response to Discovery, OC-145.
[12] Response to Discovery, OC-145.
[13] Response to Discovery, OC-995.
[14] Response to Discovery, OC-1316.

The Performance & Development Group of Human Resources tracks the training and maintains participant lists and any cost data. The Company notes with regard to the academies, participant assessments are completed after each module and on the program as a whole. Follow-up reports are completed by the manager who sent the employee for training 30, 60 and 90 days after the conclusion of the program to evaluate the learning that is being applied on the job in as observable forms as possible. These reports are prepared and submitted to the Program Manager in the Performance & Development group as well as the leadership team of the business unit from which the participant was sent.[15]

In looking to its future, PSEG expects to face a shortage of skilled workers especially in the technical trade areas. It states that its workforce planning shows that more than 25 percent of its employees would likely retire within five to seven years. Many of them are highly skilled workers in its electric and power generation businesses. PSEG states in its EUT Program Summary that "Baby Boomers" are beginning to retire and it is critical to develop a pipeline of new, trained workers.

> *We employ over 10,000 employees of which over 25% would be eligible to retire within five to seven years. If we did not take action, we could experience a significant loss of technical skills which could affect our company's ability to provide safe, reliable, electric and gas service to the customers we serve. In addition, few young people are interested in technical trade careers and even fewer are able to pass the pre-employment tests associated with the technical jobs in the company. We were facing a gap as more employees are expected to leave the company than current efforts could replace." It further noted that company leaders recognized a need to attract successful entry workers that "more reflect the diversity of our customer base." To address this shortage the company designed a program to provide a pipeline of talent needed to replace the workers that were retiring. The program partners with colleges to offer in-class instruction, internships and hands-on training in utility work. The initial program at Mercer Community College has been expanded to other Community Colleges and high schools as well as vocational schools in New Jersey. The Company notes that the program has exceeded its expectations. The Company notes that "Our program has been considered as a workforce development prototype for the utility industry. Several utilities have visited our organization and have begun to replicate the program with their local community colleges.*

PSEG is also participating in the New Jersey Energy Workforce Consortium. The mission of the consortium is to "Engage electric, nuclear, natural gas utilities, energy industries and construction in strategic, unified and results-oriented efforts…ensure a skilled workforce to meet future industry needs."[16]

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[15] Response to Discovery, OC-1316.
[16] Response to Discovery, OC-155.

PSEG is seeking to become a leader in developing New Jersey's green industry. In doing so, it seeks to pursue three critical strategies: (1) attract and train a greater number of diverse and skilled workers for the green energy industry; (2) create workforce development partnerships that help the energy industry: and (3) facilitate knowledge transfer between its green and traditional workforce.

PSEG created an energy utility technology degree program as a means to recruit and train its workforce of the future. The program is available at four two-year community colleges. It combines classroom instruction with technical apprentice-level training at PSEG's Edison Training and Development Center. PSEG states the program has been highly successful. PSEG hired 86 percent of the program's graduates. PSEG is adapting its program to prepare students for the green workforce and plans to further expand its program to prepare students for specific green jobs. PSEG states it is working with the Essex County Vocational Technical School system to create a green energy academy dedicated to preparing students for the green energy workforce. PSEG is partnering with the New Jersey Department of Labor and Workforce Development; Isles, Inc., a Trenton-based community development corporation; and other organizations to develop plans for a green workforce development training center where industry, educational institutions and government can come together to prepare New Jersey's green workforce. PSEG states preliminary plans are for the center to serve as a resource to retrain current energy industry employees, develop new employees, train the trainer, and promote economic development.

PSEG is also implementing a curriculum at Salem County Community College to prepare what it describes as the next generation of nuclear workers. It is also partnering with institutions such as Stevens Institute of Technology to help build a nuclear power engineering program.

PSEG is collaborating with high schools, colleges, the state and coalitions in Newark and Trenton to develop and implement green workforce development programs. It is also participating in partnerships with (1) New Jersey's Industry Workforce Advisory Council which seeks to identify the green workforce needs of employers and develop policies to help meet those needs; (2) Serving as Chair of the Center for Energy Workforce Development—PSEG will use this role, in part, to help improve industry efforts to recruit, train and hire a green workforce; (3) Partnering with nuclear energy trade organizations to address workforce shortages—to develop strategies to recruit and train more nuclear workers. One of the strategies being considered is an initiative to better coordinate and standardize pre-employment training programs so employees are more uniformly prepared once they enter the nuclear industry.[17]

The Senior Vice President for Human Resources stated in PSE&G's Human Resources Strategic Plan that:

> *In human resources, we emphasize recruiting well-qualified people as needed, and providing our employees with many opportunities for career growth and development." She further states "we are reinforcing our emphasis on training and development for our existing workforce. This is essential not only for professional growth, but to help us all*

[17] Response to Discovery, OC-856.

> *be more engaged and work in closer alignment toward key goals. This year's initiatives will include: new, expanded diversity training; education on the full range and value of benefit programs; leadership development; succession planning; and knowledge transfer.*

One of the strategic objectives in PSEG's Human Resources Strategic Plan is to "Attract, develop and retain capable talent/leaders through effective talent management and meaning total rewards programs/policies (pay, benefit, training, work environment)." One of HR Initiatives is to "Deploy a robust diversity training program for the purpose of increasing employees' cultural awareness, knowledge, skills and inclusion of difference identity group. An indicator of success for this initiative is listed as "Raised awareness of diversity and inclusion throughout PSEG."

> *We continue to leverage our relationships in the wider community. Our Energy Utility Technology degree program has been recognized as a model partnership between a company and local colleges to expand and diversify the workforce pipeline. We are active in nationwide partnerships such as the Center for Energy Workforce Development (CEWD). In 2009, PSEG took the lead in establishing a statewide partnership, the New Jersey Workforce Consortium, to help the future employment needs of our industry. And we work with our communities to prepare people for new energy jobs—including green jobs.*[18]

The company's performance partnership process is designed to assist the Company's managers and employees with a bi-annual assessment of an employee's performance by a goal setting and goal monitoring process, a values and behaviors evaluation, and evaluation of the employee's execution of overall job responsibilities. The Performance Management Toolkit is a document which is available to employees which describes the process that is used throughout PSEG for all MAST employee evaluations. The bi-annual assessment is carried out by both the employee and the employee's immediate manager jointly. The toolkit provides guidelines, examples, definitions and explanations of various aspects of the assessment process and format, including such components as the PSEG Performance Partnership Form and Values and Behavior Standards. Employees and managers are also provided with the description of Performance Levels and basis for their application. The performance ratings are: exceptional, exceed expectations, fully meets expectations, partially meets expectations and unsatisfactory. There are two additional designations: new (employee is new to PSEG without sufficient service time for valid assessment) and unable to rate (usually reflective of an employee on long term leave).[19]

While the Performance Partnership has a required frequency of twice a year, the Company seeks to provide continuous improvement through feedback and manager coaching. The Performance Management Toolkit is designed to give managers guidance and support for optimal ways to conduct

[18] Response to Discovery OC-995.
[19] These ratings are delineated in the "Salary, Wage and Compensation, and Benefits" chapter.

performance discussions, to keep performance directed in a positive direction, to identify performance issues early and drive performance recovery quickly. The overall objective of the Performance Partnership process is to build high performing teams by building up individual performance.

The Company advises that the Performance Partnership is designed to be highly interactive and is supported by the Empower HR system which allows for online goal setting and evaluation commentary to be entered and updated as frequently as the employee and manager chooses. Goals can be individually created or aligned with department or individual manger goals.

The Performance Partnership process also encompasses a personal development planning component which focuses on the development of skills, competencies and behaviors which underlie the employee's current responsibilities while providing an opportunity to focus on the skills and competencies required to develop and grow for future responsibilities. Development goals also reflect an agreement between manager and employee and form an integral part of the PSEG performance evaluation and management process. However, development goals are not evaluated as part of the performance rating process.

The performance evaluations for represented employees are completed on an annual basis and it is but one tool that the Company has to develop their employees, to ensure a safe and productive workplace. The evaluator reviews the employee's performance record for the appraisal period prior to developing the evaluation. The need to perform appraisal is important in this manner for the following reasons: consistent appraisals will communicate to the employee if management's expectations are met and recognize and sustain good performance; a comprehensive appraisal will develop the employee to the best of their abilities; an honest, objective appraisal will give the employee areas in which they need improvement or further development; a thorough appraisal will help the employee set "long term" career goals; complete appraisals will help supervisors select the most competent employees for promotion; and accurate appraisals are key to ongoing performance management.

The Company has a specified process for the completed performance evaluation process which includes providing the employee with the completed appraisal prior to having a meeting between the employee and the evaluator, in which the employee and evaluator discuss specific strengths, and improvement opportunities, citing specific examples and the employee is encouraged to write in comments. At the completion of the review meeting, the evaluator and the employee sign and date the evaluation form. A completed copy of the evaluation form is provided to the employee and the original is placed in the employee's personnel file.[20] The form is retained in Empower.

Recommendations

In addition to its current practice to support employee development, PSE&G should consider establishing mentorship programs for high potential employees that managers consider to be appropriate candidates for promotion within the Company.

[20] Response to Discovery, OC-152.

Affiliate Standards Compliance Training

The Company annually provides mandatory online Affiliate Compliance training to all MAST employees and in-person training to all represented employees. The training includes modules regarding the Standards of Integrity and the New Jersey and federal affiliate rules. The Compliance training and Standards of Integrity training are provided by the Legal Department.[21]

The Company should continue its practice of providing annual Affiliate Compliance training to all MAST employees and all represented employees.

Personnel Information

Access to Personnel Information

Access to Personnel information is adequate through the use of SAP and Empower. Human Resources utilizes SAP as the official system of record for employee information. SAP contains all employee and retiree related master data including, but not limited to, employee names, addresses, dates of hire, social security numbers, salary, emergency contact information, employment history (such as changes in position), etc. Local business offices can update such items as home address, emergency contact information, training records, etc. However, the update of sensitive and confidential employee information is limited to the Employee and Payroll Services organization.

While SAP continues to be the official system of record for employee information, HR utilizes a number of supplemental applications that enable HR to manage employee relations information, employee benefits, and HR processes. For example, the ***Em*power** application is an externally hosted, web based application that enables HR to manage performance management, goal management, compensation management and succession planning for MAST employees. Daily file feeds of certain employee information are sent from SAP to ***Empower*** to facilitate these processes. Another example would include information that is sent from SAP to Hewitt. Hewitt manages PSEG's employee benefits. A third example would be HR's use of another externally hosted application, for applicant tracking.

Since benefits administration is outsourced to Hewitt, they are the system of record for all employee benefit information including health and welfare, thrift and savings, long term disability, etc.[22]

We had a demonstration of the SAP HR module with PSEG staff. We found the administrative data regarding employees to be extensive and readily accessible to HR staff. Samples of the types of data available are shown in Table 25-1. Data regarding personnel performance and evaluations are housed in

[21] Interview on April 14, 2010 with Vincent Labbate, Director Performance and Development, Randi Casey, Director Talent Acquisition, and Tom Frye, Director of Human Resources, PSE&G.

[22] Response to Discovery, OC-992.

the Empower application. This data too appears readily accessible and complete and utilized to guide employee careers and to ensure that employees are contributing to the strategic direction of PSEG.[23]

Functional Areas of Human Resource Management

Functional Areas of Human Resource Management is generally adequate, but there are some areas of concern. The overall organization chart for the Human Resources Organization is presented in Table 25-2 below. It reflects 3 Vice Presidents and 3 Director level employees headed by a Senior Vice President and Chief Human Resources Officer. Only one position description out of 26 (the Director of Employee Relations and Enterprise Outreach) was missing.[24] We did not find any issues with the performance of the Human Resources organization, its organizational units, or its employees. However, we have two concerns. The first is that it is unclear to us how, without an organizational manual, PSE&G can conveniently compare functions across organizational units to avoid duplication of function or gaps in required functions. Such an organizational manual would discuss mission, function, and activities of each organizational unit. Secondly, it is unclear to us what qualitative or quantitative measures are utilized by the organization to ensure that staffing is maintained at the appropriate levels in each unit as the needs and requirements of PSE&G and its business environment change.

[23] The Empower system was discussed in detail in the section on Employee Evaluation.
[24] Response to Discovery, OC-73 and OC-73 SUPPLEMENTAL.

Table 25-1 - Sample HR SAP Employee Information

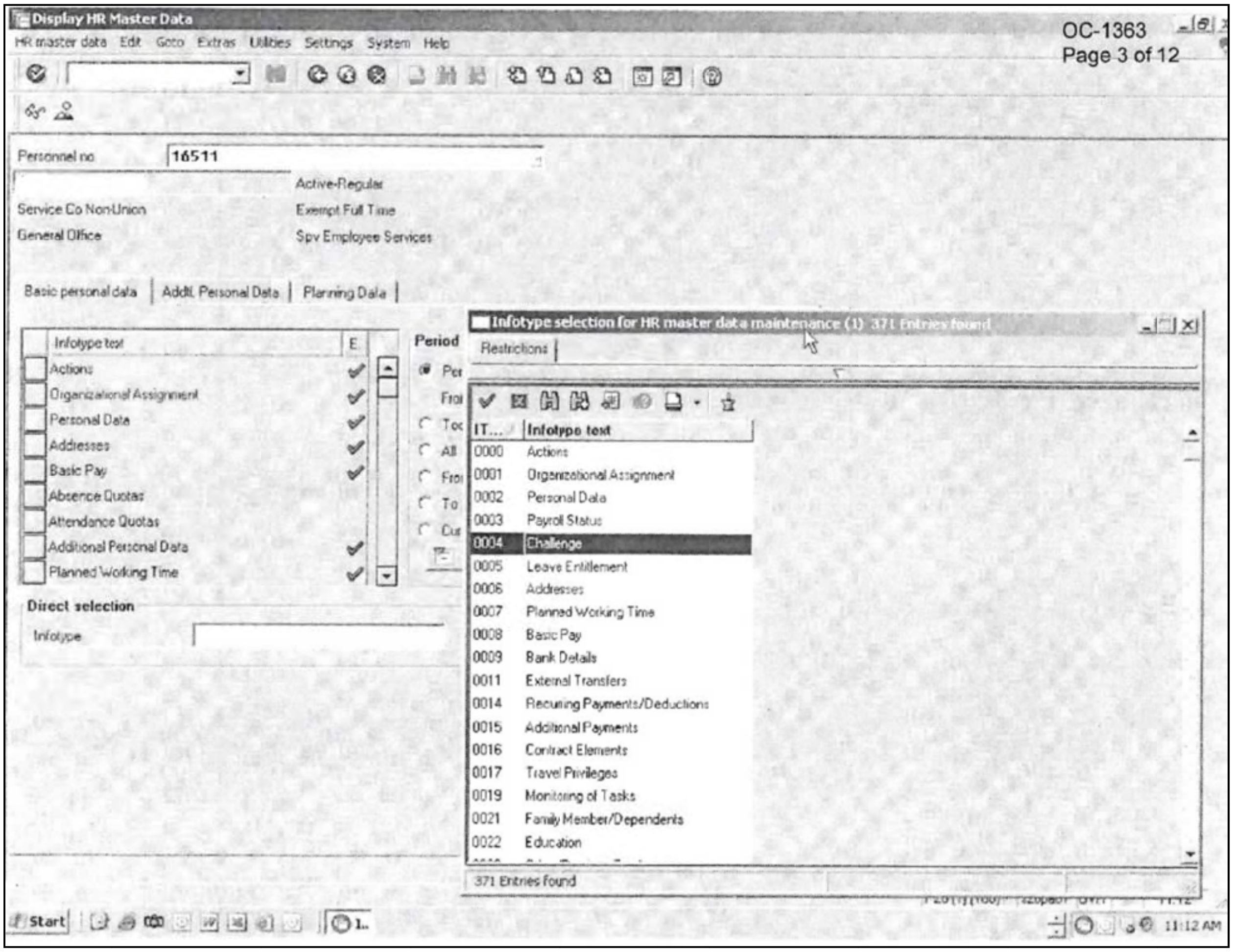
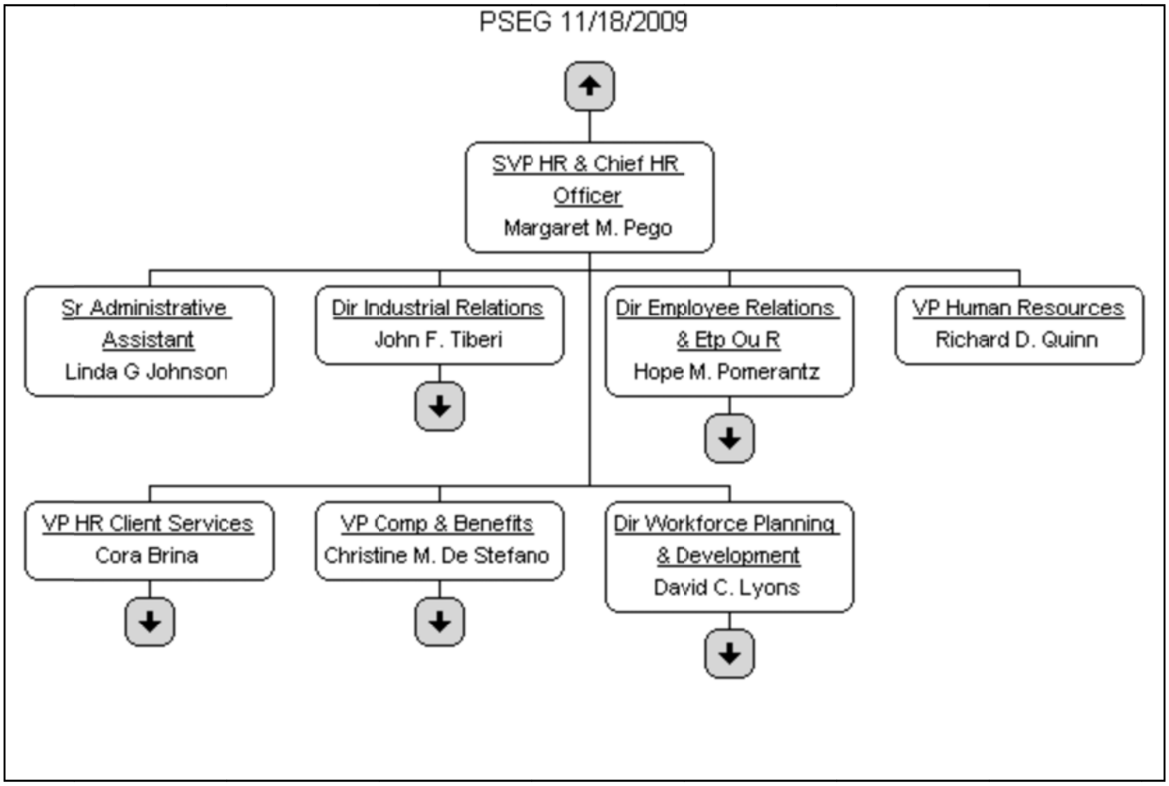


Table 25-2 – Human Resource Organization - 11/18/2009



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26. Labor Relations, Affirmative Action (AA), and Equal Employment Opportunity (EEO)

Introduction

This chapter addresses the following human resources functions:

- Labor Relations
- Equal Employment Opportunity Programs
- Affirmative Action Programs

PSEG's other human resources functions are addressed in Chapters 23 – 25.

Summary of Findings

1. PSE&G has open communications with its unions.
2. PSE&G provides adequate labor relations training to its managers and supervisors.
3. PSE&G has good constructive relationships with its unions.
4. PSE&G has a very structured dispute resolution process.
5. PSEG EEO and Affirmative Action programs are effective.

Recommendations

1. The Company should enhance its Labor Relations training with relevant National Labor Relations Board case developments and federal court decisions that may impact the scope of such matters.
2. The Company should provide coaching to managers and supervisors in units where a number of grievances have been filed to reduce the impact of the manager's or supervisor's style on the filing of grievances by employees.
3. The Company should increase the amount and frequency of diversity training that it provides to its bargaining unit employees in order to enhance a culture of inclusion.

PSE&G Communications with Unions

PSE&G has open communications with its unions. There are over 6,300 union employees at PSE&G. There are six unions, four of which are in New Jersey, one in Albany, New York and one in Connecticut. Two of the six unions (Albany and Connecticut) do not represent employees in PSE&G; these unions represent employees in PSEG Power. The Labor Relations Managers talk to the union leaders on a daily basis and the Director talks with the union leaders frequently. It was noted that there are meetings with the unions at least once a month, outside of the grievance process. There are informational meetings and quarterly meetings as needed. A union leader stated that there were good communications with the Company. There is an annual meeting with the CEO, presidents of each of the companies and the unions. In the meeting, the president of the utility goes over the scorecard with the unions as it relates to customers and seeks feedback from the unions.[1 2]

PSE&G Labor Relations Training

PSE&G provides adequate labor relations training to its managers and supervisors.

The Company's Supervisory Academy provides training to all first line supervisors who will supervise union employees on the terms and conditions of the collective bargaining agreements, positive discipline, performance management and managing availability.

Labor Relations training is provided to all first line supervisors who work with represented employees. The training provided includes the terms and conditions of the collective bargaining agreements with each of the unions, positive discipline, performance management, and managing availability. The training is provided through formal training sessions such as Management Action Response Checklist (MARC) or the Supervisory Academy or through ad hoc sessions requested by local management. The Supervisory Academy is for a three or four week period. Supervisors who work with union employees attend the Supervisory Academy for four weeks. One week deals with specific contracts that the Company has with its unions and how to deal with performance.[3] There are three or four Supervisor Academies each year. There is also a leadership academy for managers.[4]

The unions take a very active part in the Safety Councils. Best Practices are developed for safety and there is grass roots involvement. There are quarterly meetings with the Safety Councils and unions that are attended by vice presidents, union leaders, and the Labor Relations Manager in which the importance of safety is discussed.[5]

The Company also provides training to its union employees. A union representative stated that the training provided by the Company was "second to none".[6] The training includes safety training, driver training, diversity training, and sexual harassment training, among others.

[1] Interview on April 14, 2010 with Cora Brina, VP HR Client Services, Charles Miracola, Manager Benefits, Kevin Duddy, Director Business Operations & HR Strategy, John Tiberi, Director, Industrial Relations and Tom Frye, Director of Human Resources, PSE&G. Also present was Donna Luhn, Legal Specialist, BPU.

[2] Interview on August 10, 2010 with John Gerrity, President/Business Manager, Local 94, IBEW and John F. Tiberi, Director, Industrial Relations, PSEG.

[3] Response to Discovery, OC-146.

[4] Response to Discovery, OC-1316.

[5] Interview on April 14, 2010 Cora Brina, VP HR Client Services, Charles Miracola, Manager, Corporate Benefits, Kevin Duddy, Director, Business Operations & HR Strategy, John F. Tiberi, Director Industrial Relations and Tom Frye, Director of Human Resources, PSE&G. Also present was Donna Luhn, Legal Specialist, BPU.

[6] Interview on August 10, 2010 with John Gerrity, President/Business Manager. Local 94, IBEW and John F.Tiberi, Director, Industrial Relations, PSEG.

PSE&G Relationships with Unions

PSE&G has good constructive relationships with its unions. PSE&G's labor relations philosophy is to work in an environment of mutual respect and trust. This philosophy has permitted the Company to work well with its unions. PSE&G's industrial relations manager stated that in the early 1990's the Company and the unions found a way to cooperate—to continually work in an environment of cooperation, trust and respect. A union leader also stated there is a lot of cooperation between the Company and the unions. The unions have made an effort to understand the economic issues that the Company currently faces and that it maintains employment. The last layoff was in 1974. In this industry there have been a number of layoffs since 1974 and the fact there have been no PSE&G layoffs since 1974 is unusual. There has been no work stoppage since 1982. The union leader stated that the word to describe the current relationship between the Company and the unions is "trust."[7.] Communications between the Company and the unions are good. As evidence of a constructive relationship, according to a representative from PSE&G and the IBEW, given the current economic conditions the Company is facing, five of the six unions have agreed to forgo pay increases and have extended the terms of their contracts which were due to expire in April 2011 to an expiration date of April 2013. As part of the agreement for the extension of the collective bargaining agreements, there are weekly meetings between union representatives and company representatives. One union, the UWUA 601 which has approximately 1300 members, has not agreed to extend the terms of its contracts and will enter into negotiations with the Company for a contract to commence in May 2011. The Company is preparing to enter into negotiations with the UWUA 601.[8]

PSE&G Dispute Resolution Process

PSE&G has a very structured dispute resolution process. The labor relations managers and consultants are accountable for dispute resolution at PSE&G. Each Collective Bargaining Agreement provides a multi-step process for handling grievances. The first step in the process is between the first line supervisor and the shop steward. If the grievance cannot be resolved in this step, the union then processes the grievance onto the next step of the process which is heard by the department or location manager. If the grievance is not resolved at this step, the union then requests that the grievance be heard by the manager—labor relations. If the union does not accept the written reply of the manager—labor relations, the union then requests that the grievance is moved to the arbitration process. At this step both the Company and the unions present their case to an independent arbitrator who renders a decision that is binding on both parties.

[7] Interview on August 10, 2010 with John Gerrity, President/Business Manager, Local 94, IBEW and John F. Tiberi, Director, Industrial Relations, PSEG.

[8] Interview on April 14, 2010 with Cora Brina, VP, HR Client Services, Charles Miracola, Manager Benefits, Kevin Duddy, Director, Business Operations & HR Strategy, John Tiberi, Director, Industrial Relations, and Tom Frye, Director of Human Resources, PSE&G. Also present was Donna Luhn, Legal Specialist, PSE&G).

The number of grievances filed by PSEG's bargaining unit employees is lower than the top quartile for the Industrial Relations Benchmark.[9]

PSEG's HR Fast Facts reflect that there were 253 grievances filed in 2009 and 183 grievances filed in 2008[10]. IBEW has a five step process for its grievances. The other unions have a four step process. The first step of the five step process (IBEW) is between the Union Representative and the immediate Supervisor while the second step is between the grievance committee and the District Manager. In the four step process the first step is between the Shop Steward and the District Manager. The remaining three steps of both processes are essentially the same. Approximately forty to fifty percent of the grievances are filed because of discipline or discharges. According to a union leader, grievances and how far they progress have more to do with the location, particularly the manager's style and the steward's style, than other issues. The relationship between management and individuals is usually the cause. The union leader stated that coaching of the employees usually takes care of the problem. He noted that not much arbitration is required.[11] There were two filings made against the Company with the National Labor Relations Board in 2008, according to a labor union leader for Local 94, IBEW. One filing involved witnessing the sample on a drug testing and the other filing involved GPS. In the latter case, the union wanted notification of employees that they are being monitored when "out of district". The union didn't want issues or instances to accumulate before the employee was confronted.[12]

PSEG EEO and Affirmative Action Programs

PSEG EEO and affirmative action programs are effective. PSEG is substantially in compliance with equal employment opportunity and affirmative action requirements. PSEG has a policy of providing equal opportunity in all aspects of employment. PSEG's affirmative action goals and plans are established in accordance with all federal and state requirements. PSEG has had significant success in its EEO and Affirmative Action programs. PSEG programs have been widely recognized to be successful and effective.

The policy sets forth those persons within the Company to whom an employee should speak if he/she believes he/she has been discriminated against and it encourages employees to report any concerns. The policy requires Managers and Supervisors to report any known incidents. The policy states that "Applicants should also bring any concerns that they have to Employee Solutions".[13]

PSEG's EEO and Affirmative Action and sexual harassment and similar policies are posted at all of PSEG's locations and are available on PSEG's intranet website. PSEG has provided a listing of its EEO,

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[9] Response to Discovery, OC-995.

[10] Response to Discovery, OC-995.

[11] Interview on August 10, 2010 with John Gerrity, President/Business Manager. Local 94, IBEW and John F. Tiberi, Director , Industrial Relations,PSEG.

[12] Interview on August 10, 2010 with John Gerrity, President/Business Manager, Local 94, IBEW and John F. Tiberi, Director, Industrial Relations, PSEG.

[13] Response to Discovery, OC-664 and OC-151

Affirmative Action, Sexual Harassment and other Discriminatory Harassment meetings/training sessions held during the year. There are various employee publications featuring minority and non-minority men and women, including copies of recent communications using "outlook-on-line" a Company newsletter e-mailed to all employees that highlights events and issues pertaining to minorities, females, people with disabilities and veterans.

[Begin Confidential]

[End Confidential]

PSEG's Standards of Integrity provide:

> *PSEG will maintain a workplace free from discrimination. All employment decisions—including selection, hiring, placement, compensation, benefits, transfers, promotion, training, layoff, terminations, pre-placement testing, tuition aid, and disciplinary action—must be administered without regard to a person's protected status such as race, religion, creed, color, national origin, nationality, ancestry, age, present or past history of mental or physical disability, perceived disability, marital status, sex, pregnancy, affection or sexual orientation, gender identity or expression, domestic partnership or civil union status—atypical cellular or blood trait, genetic information, AIDS and HIV status, qualified special disabled veterans, veterans of the Vietnam era, any other covered veterans, or obligation to serve in the armed forces of the United States or any other status protected under applicable law (" protected characteristics"). Employees must comply with the company's commitment to maintain a workplace free from discrimination against any person based on any protected characteristics.*
>
> *PSEG is an equal opportunity employer and maintains a workplace where diversity is valued and employees of diverse backgrounds and experiences have the opportunity to succeed and reach their full career potential.*
>
> *Employees must comply with the company's commitment to equal employment opportunity, value diversity, and treat each other with respect*[16]

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[14] Response to Discovery, OC-665.

[15] Interview on April 13, 2010 with Jeff Smith, Affirmative Action Compliance Officer, PSEG, Jim Rekulak, BPU, Administrative Analyst 1, Tony Robinson, Director BGSS/BGSS Services, PSEG, Cora Brina, VP HR Services, PSEG, Ramona Blake, Diversity and Inclusion Manager, PSEG, and Tom Frye, HR, Client Services, PSE&G.

[16] Response to Discovery, OC-666.

[Begin Confidential]

[End Confidential]

PSEG has an Affirmative Action Compliance Manager at each of its locations. There are 75 Affirmative Action plans; at least one for each location. The Affirmative Action Plans set goals within each category of employees. The Affirmative Action Plans are updated on an annual basis. The plans are monitored on a semi-annual and annual basis. The senior manager at each PSEG location is responsible for affirmative action at that location. Jeff Smith, the Affirmative Action Compliance Officer, trains the managers. In February, there are two training sessions. Mr. Smith distributes the plans and provides training with respect to the plan in each session. PSEG requires that every new employee attend a training session on Working with Integrity—which includes training on Affirmative Action and Equal Employment Opportunity.[18]

We were advised that the analysis and goals are performed by job group—based upon job content and other factors. There are 26 job groups; minorities and females, veterans, people with disabilities and age are monitored. The 68 Company locations are monitored; source groups are reviewed to determine performance; efforts are measured not results. When goals are not met, efforts are made to improve outreach. There are nine staff members involved in EEO/AA company-wide.[19]

The Company benchmarks its program by Diversity Magazine, participating in Benchmark studies against peers, seeking to be in class and utilities, performing gap analysis and utilizing Saratoga data. In benchmarking of PSEG's program compared to its peers, a gap originally existed. However, training was performed, and we were advised that the new employee resource groups do well compared to benchmarks.

PSEG has three specific Affirmative Action Programs. There are AA programs for Women and Minorities, AA plans for disabled employees, and AA programs for Veterans. PSEG only sets goals for the AA plans for women and minorities. It was noted that in the past 3 years, PSEG has met 75% of its goals for

[17] Response to Discovery, OC-993. Confidential.

[18] Interview on April 13, 2010 with Jeff Smith, Affirmative Action Compliance Officer, PSEG, Jim Rekulak, BPU, Administrative Analyst 1, Tony Robinson, Director of BGSS Services, PSEG, Cora Brina, VP HR Client Services, PSEG, Ramona Blake, Diversity and Inclusion Manager, PSEG, and Tom Frye, HR, Client Services, PSEG.

[19] Interview on April 13, 2010 with Jeff Smith, Affirmative Action Compliance Officer, PSEG.

women and minorities in hiring. It was further noted that goals are key because "quotas" are illegal in hiring. As such, PSEG has to make the business case for diversity.[20]

Ralph Izzo, Chairman of the Board, President and CEO of PSEG is quoted on the Company's website on Diversity at PSEG: "Our focus on diversity and inclusion is a top priority. Diversity is a key component or organizational vision and goals-an integral part of how we seek to do business every day".[21]

PSEG has a Diversity and Inclusion Policy which states "Public Service Enterprise Group and its subsidiaries will responsibly promote diversity, inclusion and growth opportunities in its workplace to reflect the talent within the communities it serves and stimulate the development of innovative solutions to respond to the needs of its diverse constituencies." PSEG states to implement this policy, it will:

- Distinguish itself as an employer of choice for diverse candidates.
- Build strong relationships and conduct business with diverse suppliers from New Jersey and other communities it serves.
- Support Minority and Women Owned business Enterprises to help them grow and successfully compete for PSEG's business.
- Sponsor and contribute to New Jersey-based civic and community organizations that seek to improve the quality of life in diverse communities.
- Encourage its workforce to participate and take leadership positions in diverse civic and community organizations through volunteer activities, executive involvement on non-profit boards and through in-kind donations.
- Educate its workforce through programs, training, Diversity Councils and Employee Resource Groups.[22]

PSEG has certain committees, councils and groups that provide guidance to the Senior Vice President Human Resources and Chief Human Resources Officer regarding the implementation of these policies, including the Workforce Advisory Council, Diversity Councils, Employee Resource Groups and External Supplier Diversity Council.

The policy states that each member of the executive officer group of PSEG is responsible for implementing the policy for his/her respective facilities, operations and activities. The Chief Human Resources Officer maintains this policy with the advice and consent of the Vice President of Supply Chain Management and State Governmental Affairs.

[20] Interview on April 13, 2010 with Jeff Smith, Affirmative Action Compliance Officer, PSEG, Jim Rekulak, BPU, Administrative Analyst 1, Tom Robinson, Director BGSS/BGSS Services, PSEG, Dora Brina, VP, HR Client Services, Ramona Blake, Diversity and Inclusion Manager, PSEG, and Tom Frye, Director, HR, Client Services, PSE&G.

[21] http://www.pseg.com/info/careers/diversity.jsp#partners.

[22] Response to Discovery, OC-664.

[Begin Confidential]

[End Confidential]

PSEG has a number of Diversity Outreach Partnerships including Professional/University Partnerships such as the Society of Hispanic Professional Engineers, Society of Women Engineers, National Association of Black Engineers, National Association of Women MBAs, National Society of Hispanic MBAs, National Black MBA Assoc., Jackie Robinson Foundation, and Development School for Youth—All Stars Program. PSEG's Community Partnerships include: Non Traditional Employment for Women (NEW), Newark Works, One Stop Career Centers (MOET), Urban League, PENNCO, Hire Ability, Transition Assistance Programs (TAPS)—Military, Helmets to Hardhats (H2H), GI Go Fund, Williamson Free Trade Technical Trade School, Nontraditional Career Resource Center (NCRC) and US Army Reserve.[24]
PSEG Employee Resource Groups, all of which have executive sponsors that serve as mentors to the members and leadership teams, and champion the diversity strategy at the highest levels within PSEG, include: Adelante Group, AABE (American Association of Blacks in Energy), Black Data Processing Associates (NJ BDPA), GALA (Gay and Lesbian Alliances@PSEG), Minority Interchange, Inc., North American Young Generation in Nuclear (NAYGA), PSEG Vets, PSEG Women's Network, PSEG Women in Nuclear and The Young Professionals of PSEG. These groups assist with outreach.

PSEG on its website indicates that:

> *In our quest to be a world-class energy organization for diversity, PSEG proudly partners with the following organizations:*[25]
>
> - *National Black MBA Association*
> - *National Association of Women MBAs*
> - *National Association of Hispanic MBAs*
> - *Society of Hispanic MBAs*
> - *Society of Hispanic Professional Engineers*
> - *National Society of Black Engineers*
> - *Society of Women Engineers*

[23] Response to Discovery, OC-993.
[24] Response to Discovery, OC-151.
[25] http://www.pseg.com/info/careers/diversity.jsp#partners.

PSEG has had a number of accomplishments relating to EEO/AA and Diversity. It has received recognition and awards as follows:

- Disability Matters Award—based on efforts around disability awareness day
- 100% rating from the Human Rights Campaign
- Best Places to Work for NJ and Best Place to Start a Career—Business Week
- Black MBA's Partner of the Year
- 2 ½ years Exemplary Voluntary Efforts, EEO Freedom to Compete Award. It also received a perfect score of 100 on the Corporate Equality Index and Best places to Work 2010 Survey conducted by the Human Rights Campaign.[26] [27]

PSEG has also received awards and recognition for its efforts in the area of supplier diversity. It received the Corporation of the Year Award (1996, 2000, 2005) and Coordinator of the Year Award (1998, 2005) from the NY & NJ Minority Supplier Development Council; the Corporation of the Year (2004) from the Minority Supplier Development Council of PA-NJ-DE; Sustained Commitment Award (2003) from New Jersey Board of Public Utilities; Corporation of the Award (2006) from Metropolitan Trenton African American Chamber of Commerce; Diversity Star Award (2007) from Diversity Plus Publication; Corporate Sponsor of the Year (2000); Teal Heart Award (2003); Advocate of the Year Award (2005) and Women Business Leader Award (2005) from the New Jersey Association of Business Owners.[28]

PSEG Compliance with the EEO/AA Requirements

PSEG compliance with the EEO/AA requirements of Federal Executive Order 11246 is effective. To keep current on developments in this area, PSEG should consider sending appropriate staff to an Equal Employment Opportunity Commission Training Institute. The Equal Employment Opportunity Training Institute also offers customized on-site training. The Company might consider taking advantage of that on-site training if issues begin to develop in a specific area.

If PSEG has to consider a reduction in force at some point in the future, it should continue its current practice of performing an EEO four/fifth analysis to ensure that the reductions do not have a disparate impact on protected employees.

Recommendations

The Company should enhance its labor relations training by keeping executive level management, as well as, supervisory line management aware of National Labor Relations Board case developments as well as federal court decisions that may impact the scope and application of such matters.

[26] http://www.pseg.com/info/media/awards.jsp.

[27] Interview on April 13, 2010 with Tony Robinson, Director BGS/BGSS Services, PSEG; Cora Brina, VP, HR Client Services, Ramona Blake, Diversity and Inclusion Manager, PSEG, Jeff Smith, Affirmative Action Compliance, PSEG, and Tom Frye, Director HR, Client Services, PSE&G.

[28] http://www.pseg.com/familt/supplier_diversity/awards.jsp.

The Company should provide coaching to managers and supervisors in units where a number of grievances have been filed to reduce the impact of the manager's or supervisor's style on the filing of grievances by employees.

The Company should increase the amount and frequency of diversity training that it provides to its bargaining unit employees in order to enhance a culture of inclusion.

27. Remediation Costs

PSE&G is subject to liability under environmental laws for the costs of remediating environmental contamination of property due to hazardous substances that the company generated. One significant source of such contamination is the former Manufactured Gas Plant (MGP) operations of the company.[1,2]

Costs associated with the environmental remediation of these former operations has been granted special ratemaking treatment.

Summary of Findings

1. Remediation costs associated with former PSE&G manufactured gas plant sites are reviewed periodically by the BPU. The most recent reviews have resulted in no adverse findings or recommendations. However, the company has agreed to file additional information that will aid the Staff in carrying out these reviews.

2. Internal Audit's review of 2007 remediation cost activity identified three areas of concern. In a letter summarizing its most recent audit, BPU Staff noted its satisfaction with management's response to Internal Audit's recommended action plans to address these areas of concern.

3. Many of the internal controls associated with manufactured gas plant remediation costs are recorded in a document entitled Site Remediation Project Directives. We believe the various internal controls cited in it establish the basic groundwork for properly recording remediation costs associated with manufactured gas plant sites and for encouraging proper cost control.

Recommendations

1. We recommend the following be added to the minimum requirements associated with PSE&G's annual remediation adjustment charge filing:

    - The disclosure of all internal control deficiencies, significant deficiencies, or material weaknesses related to Remediation Adjustment Charge (RAC) expenditures or cost recoveries,
    - The identification of remedial steps taken by management to correct such deficiencies, significant deficiencies, or material weaknesses, and
    - The summarization of additions, deletions, or amendments to the company's Site Remediation Project Directives during the applicable RAC period under review.

[1] 2010 PSEG Form 10-K, p. 33.

[2] Certain costs incurred by Environmental Health & Safety such as internal labor are not charged to the Remediation Adjustment Charge clause (see responses to Discovery, OC-888 and OC-895). These types of costs are not the subject of the following discussion.

Background

In 1988, PSE&G requested permission to defer costs associated with the "investigation and remediation of environmental problems at [PSE&G's] former gas plant sites." The BPU authorized such deferred accounting in the following year in Docket No. GO89070658, but stressed that such accounting was not a finding for ratemaking purposes. Three years later, the BPU approved a stipulation that provided PSE&G a means by which it could collect previously incurred remediation costs from ratepayers over a six-year period through the Levelized Gas Adjustment Charge.[3]

Currently, these same types of costs are deferred and recovered through the Remediation Adjustment Charge (RAC) clause in the Societal Benefits Charges. No internal labor is charged to the deferred RAC account.[4] Prior to inclusion in rates, RAC costs for fiscal years ending July 31 are submitted to the BPU for annual review. In the two most recent decisions on the matter, the BPU approved stipulations of settlement that the work associated with such costs was "prudent and reasonable" and the costs were "reasonable and appropriate for recovery." Recovery of approved RAC costs is achieved by amortizing costs over a seven-year rolling average period with an allowance for carrying charges (based on seven-year treasuries plus a premium of sixty basis points).[5]

[3] Order Approving Stipulation Regarding Gas Plant Remediation Costs dated December 30, 1991 (Docket No. GR91071226J) provided in response to Discovery, OC-990.

[4] According to the company, although there is no formal BPU decision or order prohibiting the inclusion of internal labor in RAC costs, it is perceived that such a request would meet resistance, and the company has therefore chosen not to pursue such a proposal.

[5] Decision and Order Adopting Initial Decision and Approving Stipulation of Settlement dated July 31, 2009 (Docket No. ER08121041) and Decision and Order Adopting Initial Decision and Approving Settlement for RAC 17 dated August 4, 2010 (Docket No. ER09110921) provided in response to Discovery, OC-1472.

The recent magnitude of these expenditures is demonstrated in the following table:

Table 27-1 – MGP Remediation Program, Net Expenditures

PSE&G MGP Remediation Program Net Expenditures		
Month	2008	2009
January	$62,723	$176,927
February	1,263,101	2,005,958
March	1,370,513	1,414,685
April	2,282,999	1,196,333
May	2,154,595	2,079,195
June	3,122,061	319,620
July	4,334,815	949,862
August	4,684,512	458,827
September	5,880,470	(184,791)
October	6,107,477	1,822,898
November	5,808,830	1,852,869
December	3,360,332	4,518,330
TOTAL	$40,432,428	$16,610,713
Source: Response to Discovery, OC-892 (some summing required). 2009 amounts above were net of insurance recoveries of $1,590,709. 2008 insurance recovery amounts were unavailable (response to Discovery, OC-47, p. 3 of 21)		

Since there is a difference in the timing of when PSE&G incurs the costs and when they are recovered from ratepayers, outstanding uncollected amounts are ultimately deferred on the balance sheet. Per agreement with the BPU, expenditures are allocated 60 percent to gas customers and 40 percent to electric customers.[6] Deferred remediation costs outstanding as of year-end 2007, 2008, and 2009 were as follows:

Table 27-2 – Deferred RAC Costs

PSE&G Deferred RAC Costs		
Date	Gas	Electric
December 31, 2007	$71,440,965	$42,579,308
December 31, 2008	86,124,162	55,911,996
December 31, 2009	83,817,345	60,190,355
Source: Response to Discovery, OC-892.		

As part of the stipulation of settlement that involved RAC costs that were incurred during the time period August 1, 2008 to July 31, 2009, PSE&G agreed to certain "minimum filing requirements" for future RAC filings submitted to the BPU. These requirements included, but were not limited to:[7]

- Providing general descriptions of services rendered by vendors at each site,

[6] Response to Discovery, OC-47.
[7] Response to Discovery, OC-1472.

- Providing certain filings and correspondence between the company and the New Jersey Department of Environmental Protection on the most significant projects,
- Providing support for significant expenditures made on the most significant projects,
- Providing documentation on insurance reimbursements made during the period,
- Providing internal and external audit reports concerning the RAC and any management responses to findings, if applicable,
- Providing notice of any potential changes to the company's expected remediation liability,
- Providing calculations of taxes, interest, and carrying charges impacting RAC costs or associated recovery,
- Providing bid information on the most significant contract awards entered into during the past year that involve RAC costs,
- Providing information on the most significant change orders involving RAC costs during the past year,
- Providing the status of efforts at each site, including estimated milestone dates, and
- Providing information on unusual delays.

We believe these additional filing requirements set a reasonable baseline of data that can be used by the BPU and Staff in assessing the company's annual RAC filing. However, other information that would both be beneficial in this review and not expected to be an undue burden on the company to compile would be:

- Disclosing any internal control deficiencies, significant deficiencies, or material weaknesses related to RAC expenditures or cost recoveries,
- Identifying remedial steps taken by management to correct such deficiencies, significant deficiencies, or material weaknesses, and
- Summarizing the additions, deletions, or amendments to the company's Site Remediation Project Directives during the applicable RAC period under review.

The former is developed as part of the Sarbanes-Oxley review process and is distinct from the work performed by Internal Audit.

The latter involves a document that was cited by the company as evidence of the internal controls it employs to ensure that MGP remediation costs are properly recorded and reasonable.[8]

Historical Reviews of PSE&G Remediation Costs

On August 31, 2010, the BPU Division of Audits released a letter to the company indicating that its audit of PSE&G's MGP Remediation Adjustment Clause for the period August 1, 2003 to July 31, 2006 had been completed. In this letter, the Staff noted that no material issues had to be brought to the BPU's attention as a result of the audit. Since no findings or recommendations resulted from the audit, no formal audit report was issued.[9]

[8] Response to Discovery, OC-47.
[9] Response to Discovery, OC-989 (Supplemental) and informal correspondence with the BPU Staff.

The BPU Staff letter noted that PSE&G's RAC is the subject of periodic internal audits. The most recent audit cited by BPU Staff was an internal audit that covered 2007 activities and was reported to management in February, 2008.

[Begin Confidential]

[End Confidential]

BPU Staff followed up on the corrective actions taken by management to address Internal Audit's recommendations and was satisfied with PSE&G's response. Staff intends to monitor future compliance with these recommendations.[11]

Internal Controls Over Remediation Costs

When asked to list the internal controls employed by the company to ensure costs and ratepayer recoveries of MGP remediation costs are properly recorded and reasonable, management cited four different documents and/or schedules:[12]

- Site Remediation Project Directives
- Operation & Maintenance Expenditures ("Report 4")
- BPU Monthly MGP Expenditures Report

[10] Response to Discovery, OC-608 (Restricted On-Site Only).
[11] Response to Discovery, OC-989 (Supplemental).
[12] Response to Discovery, OC-47.

- NJBPU Annual Filing

The latter three are either internal or external reports that management and third parties can review for completeness and/or reasonableness of expenditures after the fact. While these reports certainly play a valuable role within the internal control framework, our focus will be on the much more comprehensive first document listed, the Site Remediation Project Directives.

[Begin Confidential]

[13] Response to Discovery, OC-893 (Restricted).

[14] Response to Discovery, OC-893: SRP-PMD-02 (p. 7 of Revision 11) and SRP-PMD-09 (p. 1 of Revision 12) (Restricted). Note: SRP = Site Remediation Projects, PMD = Project Management Directive.

[15] Response to Discovery, OC-893: SRP-PMD-03 (pp. 2 and 4 of Revision 7) (Restricted).

[16] Response to Discovery, OC-893: SRP-PMD-09 (Revision 12) (Restricted).

[17] Response to Discovery, OC-893: SRP-PMD-08 (Revision 5) (Restricted).

[End Confidential]

Internal and external reviews of remediation costs on a routine basis promote the proper recording and prudency of incurred expenditures. When processes are subject to regular, independent review; there is a deterrent effect on improper accounting and spending. This is most apparent in the BPU's review of the annual RAC filings and recently-completed audit of the RAC. In all instances, there were no findings of inappropriate actions taken by PSE&G or its affiliates.

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28. Support Services

This chapter covers PSEG's management of the following support functions:

- Information Technology
- Security and Claims
- Law Department
- Corporate Records and Library
- Fleet Management
- Supply Chain

Summary of Findings

1. In terms of cost, IT is by far the most significant support function in PSEG Services Corporation, accounting for more than 38 percent of the service company's total incurred cost (excluding convenience payments) during the period 2007 through 2009.

2. Nearly three-fourths of IT's cost was charged to the Utility operating company; however, this was skewed to some degree by the iPower project, which comprises a significant percentage of the $111 million in Utility charges in the Client Project service line.

3. iPower was implemented in 2009. It is described as "the combination of SAP processes and applications, which replaced the Customer Information System (CIS), Gas Service Information Management System (GSIMS) and the majority of the Meter Data Repository (MDR)".

4. PSEG works with the BPU and the New Jersey Office of Homeland Security to develop and implement policies that reflect "best security practices." PSEG participated in the development of a utility sector "best practices" manual following September 11, 2001. The command center was implemented after 9/11/2001 to provide centralized, 24/7 security oversight of all critical facilities. PSEG indicated that it was the first utility in the region to implement such a center.

5. The claims and security functions underwent an organizational redesign between 2007 and 2009. This reduced full-time positions from 50 to 44. In addition, the overall cost was reduced by approximately $3 million between 2007 and 2009.

6. During the review period PSEG utilized dozens of different law firms, and spending per firm seldom exceeded $1 million in a given year. Additionally, the few firms with the highest billings in one year did not have the highest billings in the next. This is consistent with a competitive, rather than a relationship-driven procurement process.

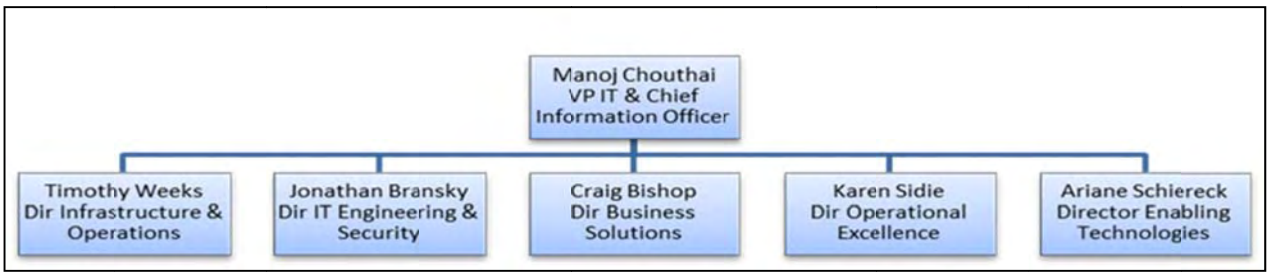
7. PSEG began the balanced scorecard process in 2008 for the Supply Chain Division. For the most part, the 2009 results met the targeted goal for the year. One metric that is noticeably under expectations is the measurement of customer satisfaction. The company measures customer satisfaction through a 13 question survey. A couple of the questions that received the lowest scores in the survey related to how well SCM understood the business requirements of their internal (PSEG) customers and how well SCM did in resolving supplier-related performance and quality concerns.

Information Technology

Organization

As of April 30, 2010, PSEG's IT organization had 225 full time equivalent employees and was headed by Manoj Chouthai, Vice President and Chief Information Officer (CIO). During 2010 Mr. Chouthai reported to PSEG's Chief Financial Officer. Reporting to Mr. Chouthai were the following directors: Infrastructure and Operations (Timothy Weeks, Director); Engineering and Security (Jonathan Bransky, Director); Business Solutions (Craig Bishop, Director); and Operational Excellence (Karen Sidie, Director).

Table 28-1 – PSEG Information Technology Organization



Infrastructure and Operations – Key positions reporting to the Director as of April, 2010:[1]

- Manager Data Security (Debra Suckiel)
- Manager IT Applications Mgt & QA (Vincent Scatuccio)
- Manager IT Client Services (Jean Gelin)
- Manager Desktop Management (Jeffrey Miller)
- Manager System Services (Wilson Diaz)
- Director SAP Center of Excellence (Stephen Roche)

Major groups within Infrastructure and Operations include the following. Network Operations runs the data center. Application Management manages vendor contracts, financial agreements, service quality and vendor responsiveness for more than 100 applications. Much of the direct application support is

[1] Response to Discovery, OC-826.

outsourced to companies such as Tata Consulting Services and IBM. Client Services includes approximately a dozen people who run the help desk and process client (internal company) orders for assistance. Desktop Management includes 10 employees who manage approximately 10,000 desktop and laptop computers and 2,500 mobile data terminals. Much of the actual help desk "help" and the field maintenance of computers and MDTs was outsourced to CompuCom in 2010. The primary role of PSEG employees in the System Services function is server administration and support, support of core infrastructure services and database administration.[2] The Director SAP Center of Excellence area was moved to Infrastructure and Operations as part of a departmental restructuring in October 2009. The function is responsible for the Enterprise Application Services (EAS) product, including the core SAP ERM system and iPower.[3]

Enabling Technologies – Positions reporting to the Director in 2010 included:[4]

- Director Technology Solutions (Karen Bassin-Reif)
- Manager Integration Center of Excellence (Saruabh Sachdeva)
- Manager Data and Business Excellence (Lorenzo Ball)

Enabling Technologies include "Centers for Excellence," which are responsible for the architecture for new applications, "integration hubs" (for SAP) and various other services.[5]

IT Engineering & Security – Positions reporting to the Director at the end of April, 2010 included:[6]

- Manager IT Engineering (Lorena Hoopes)
- IT Security Manager (Brian Rudowski)
- IT Supervisor (Leslie Tighe)

Engineering is responsible for the design of systems, standards for network equipment, standards for the type and configuration of services, communications and e-applications (including web, social networking, new and emerging technologies). IT Security provides support for system access (processing requests for access, including management of LAN IDs). In addition, it establishes and maintains network security standards, ensures appropriate policies are set, and responds to audit issues raised by Internal Auditing.[7]

Business Solutions – Positions reporting to the Director in April 2010 included:[8]

- Monitoring IT Business Partner (Greg Salvatoriello)

[2] Interview, Robert Czyzewski, Managing IT Business Partner, June 10, 2010
[3] Based on information provided in an email from Mally Becker, dated October 26, 2011.
[4] Response to Discovery, OC-826.
[5] Interview, Robert Czyzewski, Managing IT Business Partner, June 10, 2010
[6] Response to Discovery, OC-826.
[7] Interview, Robert Czyzewski, Managing IT Business Partner, June 10, 2010
[8] Response to Discovery, OC-826.

- Monitoring IT Business Partner (Gary Bernaski)
- Monitoring IT Business Partner (Robert Czyzewski)
- Monitoring IT Business Partner (James Gallagher)
- Monitoring IT Business Partner (Brian Schroeder)

Business Solutions includes approximately 65 employees performing the "Business Partner" functions for each operating company and segment. They determine what the client businesses need and facilitate acquisition. They provide implementation assistance and business representation for major software applications (iPower, SAP). The primary responsibility of the Business Partners is to make sure major applications have reached "steady state" and can be supported. They do this by creating plans that consider what will be needed and how it should be developed and optimized. An Asset Management group is responsible for developing asset management programs, for developing hardware practices and optimizing "toolkits" (PCs, smart phones, printers and other hardware elements).[9]

Operational Excellence – Positions reporting to the Director in 2010 included:[10]

- IT Delivery Manager (Irma Pittman)
- IT Strategic Vendor Manager (Michael Bauer)
- Principal (Raymond Castellano)
- Lead Consultants & Associates (3)
- Office Supervisor (Robert O'Grady)

Operational Excellence, consisting of approximately 25 employees, is responsible for scorecards and scorecard tracking, disaster recovery and special projects. Strategic Vendor Management partners with the Supply Chain function to look for acquisition-related cost saving opportunities, create requests for proposals, and review of contracts. A Sarbanes Oxley team focuses on compliance issues and works with Internal Auditing. Office Supervision provides logistical support, IT billing and timesheet administration, procurement and purchase card management and general office administration. A Project and Portfolio Management Office sets standards for project documentation and execution and handles project proposals, project financial forecasts, test plan execution, project reporting, and acceptance phase work. They also develop life cycle guidelines.[11]

Costs and Cost Distributions

In terms of cost, IT is by far the most significant support function in PSEG Services Corporation, accounting for more than 38 percent of the service company's total incurred cost (excluding convenience payments) during the period 2007 through 2009.[12] The following table summarizes cost distributions to operating companies during the review period.

[9] Interview, Robert Czyzewski, Managing IT Business Partner, June 10, 2010.
[10] Response to Discovery, OC-826.
[11] Interview, Robert Czyzewski, Managing IT Business Partner, June 10, 2010.
[12] The next most significant service company function in dollar terms, Environmental, Health and Safety, incurred less than a third of the cost incurred by IT in 2007 and 2008, and less than one-sixth the cost incurred by IT in 2009.

Table 28-2 – Cost Distributions to Operating Companies by Service

PSEG Information Technology Cost Distributions to Operating Companies by Service 2007-2009 ($000s)						
	2007		2008		2009	
	Amount	Pct.	Amount	Pct.	Amount	Pct.
Holdings	1,295	1%	940	1%	764	1%
Power	40,164	26%	43,572	25%	42,355	28%
Utility	113,971	73%	132,198	75%	108,413	72%
Total	155,430	100%	176,710	100%	151,532	100%
Source: OC-554						

Nearly three-fourths of IT's cost was charged to the Utility operating company; however, this was skewed to some degree by the iPower project, which comprises a significant percentage of the $111 million in Utility charges in the Client Project service line. For the service lines other than Client Projects, IT costs split roughly two-thirds Utility and one third Power, with relatively insignificant charges to Holdings.

Table 28-3 – Cost Distributions to Operating Companies by Service Line

PSEG Information Technology Cost Distributions to Operating Companies by Service Line 2007-2009 Combined ($000s)				
Service Line	Holdings	Power	Utility	Total
Application Support Products	0	22,347	86,746	109,093
Business Support Products	608	16,903	6,488	23,999
Client Projects	441	18,323	111,435	130,198
Commercial Products	448	11,722	45,944	58,114
Desktop Products	531	21,110	47,580	69,221
SAP / ERM	973	35,685	56,390	93,047
Grand Total	2,999	126,091	354,582	483,672
Percentages	0.6%	26.1%	73.3%	100.0%
Source: OC-554				

Based on the significance of the costs involved, we asked PSEG to describe the processes in place to assess the costs and benefits of IT projects.[13] PSEG stated that policy requires that capital investments, including IT capital projects, undergo a formal governance review, including a cost-benefit analysis. Capital projects valued at $10 million or more must be reviewed and approved at the corporate level by

[13] Response to Discovery, OC-431.

the PSEG Capital Review Committee.[14] The company stated that IT capital projects must comply with the PSEG Financial Risk Management Policy.

PSEG indicated that non-capital IT investments go through a similar review process utilizing procedures unique to each operating company. The operating subsidiaries have IT councils to provide governance, cost-benefit review and oversight. The councils do not have approval authority, but offer recommendations to decision makers and service as points of contact to assess the costs and benefits of non-capital IT investments.

PSEG Information Systems

The significant information systems managed by the IT function, major upgrades (executed and planned) and the distribution of associated costs to the operating companies are summarized as follows:[15]

- SAP Enterprise – SAP and its various component systems are used for enterprise resource planning and management. It serves all operating companies and business segments. During the 2007-2009 review period SAP supported core business processes for Human Resources, Financial Reporting and Management, Supply Chain Management, Work Management and Environmental, Health and Safety Practice Areas. It includes a transactional system, and applications to support reporting and application integration. The last major enhancement was an upgrade to SAP version ECC 6.0. A major system upgrade is planned for 2015, with minor "enhancement packs" planned for installation between 2011 and 2014. Costs incurred by PSEG Services Corporation for operating and supporting SAP are charged through the Enterprise Application Services product. EAS product charges are distributed in proportion to active system users (measured by IDs) and employee headcount in each operating company.

- SAP-Based iPower – PSEG describes iPower as "the combination of SAP processes and applications which replaced the Customer Information System (CIS), Gas Service Information Management System (GSMIS) and the majority of the Meter Data Repository (MDR)." It was implemented in 2009. A service dispatch module will be added in 2012 and "other SAP system upgrades" are planned for 2015. Among the components of the new CIS are web-based customer self-service, Call Center, Credit and Collections, Field Operations, Billing and Appliance Service. The costs of this system are associated only with the Utility operating company (PSE&G). The implementation of iPower and related issues are discussed in the chapter on Customer Service.

- Outage Management (OMS) – OMS manages electric distribution service interruptions that can occur during normal conditions as well as emergency and storm situations. OMS maps the location of outages and estimates the number of affected customers. It is used to dispatch and

[14] Capital projects under $10 million go through a similar process, but are under the jurisdiction of the individual operating companies. According to PSEG, review boards within the operating companies assess the viability, risk and cost-benefit of such projects.

[15] Response to Discovery, OC-430.

complete outage-related work and provides outage statistics and restoration times used by the NJBPU and other government agencies. OMS software was upgraded in 2007. Server hardware and software upgrades are planned for 2011. Costs are charged entirely to the Utility operating company.

- Geographical Information System (GIS) – GIS provides the geographic location of facilities. It is designed to maintain customer-to-transformer circuit linkage information. GIS supports the OMS system. GIS server hardware and software was upgraded in 2006. Another upgrade is planned for 2011. Costs are charged entirely to the Utility operating company.

- Delivery Work Management System (DWMS) – DWMS is employed by the electric and gas distribution organizations to manage (plan, assign, complete, document) work activities. It is connected with mobile data terminals (MDTs) in field operations vehicles to dispatch and receive field work information. Software was upgraded in 2007. Server hardware and software is scheduled for upgrade in 2011. MDTs are replaced continuously under a lifecycle program. Costs are charged entirely to the Utility operating company.

- Energy Management System (EMS) and SCADA – The transmission EMS is a redundant, distributed system with a primary and back-up control center. The transmission SCADA subsystem communicates with approximately 140 sites via remote terminal units, collecting operational information from substations, switches and generating stations. Real-time information is transmitted to utility electric system operators through displays and alarms. The system provides for control of field devices. The distribution SCADA system is comprised of four independent systems within PSE&G's divisional headquarters. These systems communicate with almost 2,000 locations in the service territory, monitoring the status of distribution facilities. The system was upgraded in 2007 and in 2010. Concerning the cost of the system, PSEG stated the following:

  > The cost to install and operate the transmission EMS and distribution SCADA systems is directly funded by PSE&G. PSEG Energy Resources and Trading has limited access to parts of the EMS system monitor specific generation data. ER&T compensates PSE&G for the use of the system based on actual fully loaded cost of shared or exclusively operated system components. These components include such items as remote terminal units, user terminals, telecommunications lines, system programs, licensing, etc.

- Other Systems:
  - Radiological Access Control System – This system, known as ProRad, monitors and records occupational radiation exposure for people working or visiting nuclear generation sites. It is charged to the Power operating company.

- Primavera – This is a project management tool used by plan engineers to develop and manage project plans and track progress toward completion. Primavera is charged to the Power operating company.
- Document Control Record Management (DCRMS) – DCRMS provides document management, distribution, retrieval and access control for a variety of information types, including database records, scanned drawings, CAD files, test documents, spreadsheets and technical manuals. DCRMS is used by and charged to the Power operating company.
- Zai*Net – This is an energy trading and risk management system used to enter, store and report financial transactions in support of the risk management function. It is charged entirely to Energy Resources and Trading.
- GasMaster – This is a system used to manage (schedule, track, report) physical gas transactions. It is charged entirely to Energy Resources and Trading.
- PI – This is a decision support system that collects and stores information from operational systems (Electric Transmission, Electric Delivery, Fossil, Nuclear and ER&T) for future analysis. Charges for individual PI systems used by each operating company are charged to that company.

IT Performance

In 2008, IT's Vice President-level scorecard tracked 18 metrics. This increased to 28 in 2009. Selected operational metrics from the 2008 and 2009 scorecards are discussed below.

Table 28-4 – Key Operational and Economic Scorecard Metrics

PSEG Information Technology Key Operational and Economic Scorecard Metrics				
	2008		2009	
Category	Target	Achieved	Target	Achieved
IT Critical System Unplanned Outages (Minutes)	not avail.	not avail.	1,118	606
IT Critical System Availability (%)	99.88	99.98	not avail.	not avail.
SAP / OMS Unplanned Outage (Minutes)	not avail.	not avail.	3,675	6,011
IT Project Delivery Performance (%)	not avail.	55.0	70.0	65.0
Resolve Desktop Problems (%)	85.0	91.8	92.0	90.9
First Call Resolution (from 2008 scorecard) (%)	87.0	92.9	87.5	not avail.
Moment of Truth Survey (0 to 4 Scale)	3.61	3.76	3.77	3.72
Security - New LAN ID (%)	not avail.	94.0	94.0	98.1
Security - SAP ID (%)	not avail.	82.2	83.0	86.7
UNITE Gap to Top Quartile	not avail.	4.2	3.0	5.3
Source: OC-425, OC-409				

Critical System Unplanned Outage Minutes – This metric was added to the IT VP's scorecard in 2009 and appears to have replaced critical systems availability, discussed below. Unplanned outage minutes are targeted for 22 critical systems. The target for 2009 was significantly higher than achieved outage minutes in the prior three years, possibly due to an expectation that iPower would create unplanned outages in several SAP subsystems. Scores for specific systems and subsystems are shown below. As summarized in both tables, in 2009 PSEG exceeded its overall target for non-SAP systems, but did not meet its target for SAP, possibly due to issues connected with the implementation of iPower.

Table 28-5 – Critical Systems Outage Minutes

PSEG Information Technology Critical Systems Outage Minutes		
Category	2009	
	Target	Achieved
Internet	1118 Combined	132
Email		241
DWMS		-
GIS		-
PI		83
Zai*Net		-
GasMaster		-
DCRMS		78
ProRad		72
Subtotal non-SAP		**606**
SAP Enterprise	525	1,340
SAP CRM	525	1,360
SAP MI	525	1,992
SAP Customer Web	525	1,236
SAP Human Res.	525	-
SAP XI	525	83
OMS	525	-
Subtotal SAP	**3,675**	**6,011**
Source: OC-924		

Critical System Availability Percentage – In 2008 this measured aggregate systems performance for 13 "critical systems," including SAP, CIS (component of iPower), GIS, GSMIS, PI, DWMS, OMS, Email and Internet, among others. It measures actual available hours as a percentage of planned available hours. It was dropped from the VP level scorecard in 2009.

Project Delivery Performance – This metric appears to be an equally weighted blend of project cost and project delivery (schedule) indexes. The IT scorecard package does not include a description of what the index percentage means or how it is calculated. However, a note states that the "industry benchmark . . . recognizes that large projects typically do not perform much better than at the 50% level." According to the metrics provided in response to OC-409 and 425, PSEG's IT function achieved a 55 percent performance level in 2008 and a 65 percent level in 2009.

Resolve Desktop Problems – This measures IT's ability to fix all in-warranty desktop problems within two business days of being notified of the problem. This metric was added to the VP's scorecard in 2009, as first-call resolution (discussed below) was dropped. Achieved resolution averaged around 90 percent between 2006 and 2009.

First Call Resolution – This measures the percentage of time a client problem is resolved during the first interaction with the PSEG's help desk, without assistance from another member of the IT staff or with an automated resolution tool. It is a commonly used metric for evaluating the effectiveness of technical support activities. Plans were to raise the target level from 87 percent in 2008 to 90 percent by 2012. Actual data for 2009 is unavailable because the metric was removed from the Vice President's scorecard after 2008. The identified Gartner industry benchmark for help desk first call resolution is 80 percent. The help desk function is largely outsourced to contractor CompuCom.

Moment of Truth (MOT) Survey – The MOT is a web-based client satisfaction survey rank on a scale of 0 to 4. The metric calculation is an average score of MOT surveys received. Further descriptions of the survey contents were not available in the scorecard descriptive information provided. PSEG IT achieved an MOT score of 3.65 in 2006, 3.68 in 2007, 3.76 in 2008 and 3.72 in 2009.

Security – New LAN and SAP IDs – These metrics measure the percentage of time IT creates new LAN or SAP IDs for employees within two business days of request, and contractor IDs within six business days. The ID metrics were added to the IT VP's scorecard in 2009. It is interesting to note that between 2005 and 2009, performance in the creation of LAN IDs improved (from 90.3 percent in 2005 to 98.1 percent in 2009), while performance in the creation of SAP IDs degraded (from 97.1 percent in 2005 to 86.7 percent in 2009).

UNITE Gap to Top Quartile – UNITE is IT benchmarking cooperative. The "UNITE Gap" metric measures the financial gap between PSEG's performance and the UNITE top quartile benchmark value. This is another metric that is not well described in the scorecard descriptions provided in response to OC-409, and it is somewhat unclear what it is measuring or how it is calculated. However, lower indicates better (meaning a "gap" of $0 would presumably be in line with the UNITE top quartile). PSEG's realized value of $5.3 million in 2009 did not meet the target of $3 million.

In addition to the service-oriented scorecard metrics shown in the table above, IT maintained targets and monitored service levels in various client service areas. These are defined and summarized in the following table.

Table 28-6 – Client Service Metrics – Non-Scorecard

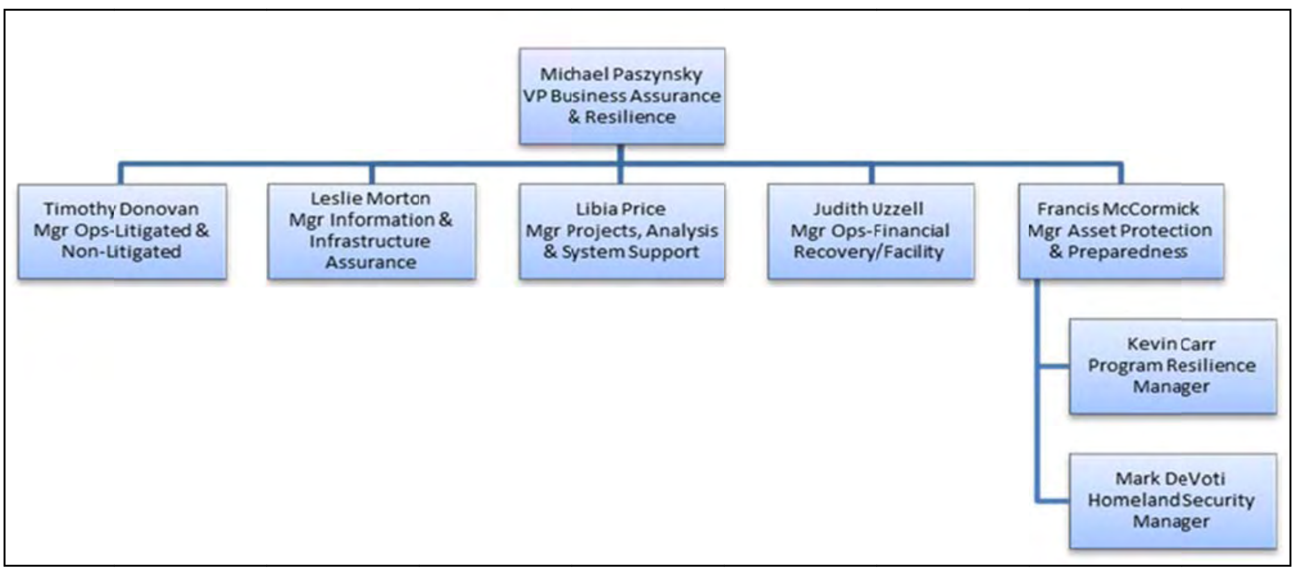
PSEG Information Technology Client Service Metrics - Non-Scorecard					
		2008		2009	
Category	Definition	Target	Achieved	Target	Achieved
Install Client Desktop Peripherals	Percent "in-line w ith industry best practices," 5 units or less per request	85.0%	90.4%	85.0%	93.4%
Production Application Issue Response	Response w ithin 2 hours, or response w ithin 30 min. for "severity level 1."	98.0%	98.9%	98.0%	94.9%
Problem Aging	Pct. problems resolved w ithin 30 days	95.0%	98.8%	95.0%	91.4%
Email Availability	Availability percentage	99.9%	100.0%	not avail.	not avail.
Internet Availability	Availability percentage	99.9%	100.0%	not avail.	not avail.
Call Unabandoned Rate	Client Svc Center, 1 minus the call abandoned rate	95.0%	96.8%	95.0%	95.5%
Call Service Level	Client Svc Center, percentage of calls answ ered w ithin 60 seconds	85.0%	90.4%	85.0%	87.4%
Source: OC-924					

Security and Claims

Organization

In 2010 PSEG's Security and Claims functions were headed by Michael Paszynsky, Vice President, Business Assurance and Resilience (hereafter Security and Claims). Mr. Paszynsky reported to the Executive Vice President and General Counsel, J.A. Bouknight, Jr. Below is an organization chart showing the key reporting relationships in the Security function as of April, 2010. At this point in time, Security and Claims had 41 employees, split approximately evenly between the security and claims functions.[16]

Table 28-7 - PSEG Security Function Organization, April, 2010



[16] Response to Discovery, OC-825.

In 2010 Security and Claims primary responsibilities and functions included the following:[17]

- Asset Protection & Preparedness – This includes an executive crisis management team (with strategic and operational members), business continuity planning, business interruption management and security incident investigations.
- Information and Infrastructure Assurance – This includes cyber-security assurance and investigations, forensics, the operation of a security command center monitoring more than 100 facilities (built in 2003) and some regulatory compliance. It also includes contracted guard service, with approximately four dozen guards stationed at various facilities.
- Financial Recovery and Facility Relocation – This consists of Business Assurance consultants who manage projects requiring facility movement and handle related property damage claims. Their primary function is to protect infrastructure that can be damaged when facilities are installed or moved.
- Claims Processing and Investigation – This involves handling and processing litigated and non-litigated claims other than those related to facility movement, described above.

Costs and Cost Distributions

The table below summarizes Security and Claims cost distributions among operating companies.

Table 28-8 – Cost Distributions to Operating Companies by Service

PSEG Security & Claims Cost Distr butions to Operating Companies by Service 2007-2009 ($000s)						
	2007		2008		2009	
	Amount	Pct.	Amount	Pct.	Amount	Pct.
Holdings	402	2.9%	232	1.8%	72	0.6%
Pow er	3,726	26.6%	3,099	24.6%	1,477	13.3%
Utility	9,863	70.5%	9,257	73.5%	9,540	86.0%
Total	13,991	100.0%	12,588	100.0%	11,089	100.0%
Source: OC-554						

The following table shows the costs broken into services for the review period as a whole.

[17] Interview, Libby Price, Manager Projects, Analysis and Systems Support and Frank McCormick, Manager, Asset Protection and Preparedness, June 11, 2010.

Table 28-9 – Cost Distributions to Operating Companies by Service

PSEG Security & Claims Cost Distributions to Operating Companies by Service 2007-2009 Combined ($000s)				
Service Line	Holdings	Pow er	Utility	Total
Business Interruption Mgt.	10	415	567	992
Command Center	0	136	1,522	1,658
Corporate Security	513	6,079	9,616	16,208
Crisis Management Ctr/	37	470	744	1,251
Guard Service	135	499	1,293	1,926
Security Planning & Ops	10	688	2,663	3,361
Subtotal Security	705	8,287	16,404	25,396
Claims	1	16	12,255	12,272
Subtotal Claims	1	16	12,255	12,272
Total	706	8,303	28,660	37,668
Percentages	2%	22%	76%	100%
Source: OC-554				

Prior to 2008, all corporate security activities, apart from the crisis management center, were essentially lumped together for budgeting and pricing purposes. Beginning in 2008, corporate guard service was broken out separately. In 2009, corporate security activities other than guard services were broken into business interruption management, command center and security planning and operations. As the first table demonstrates, as total security and claims costs declined during the review period, costs for the Utility operating company declined less significantly; consequently, Utility's share of total cost increased from 71 percent in 2007 to 87 percent in 2009.[18] As discussed in the chapter on PSEG Services, the increase in Utility's cost percentage appears to have occurred because a significant share of costs that had been allocated as general security using the Enterprise method was moved into more specific services that tend to be allocated based on the number of "devices" (mainly security cameras). Since Utility has a higher relative share of devices than its share of costs allocable under the Enterprise allocation factor, its share of total security costs increased when costs were moved into cost pools allocated directly or indirectly based on such devices.

[18] As discussed in the chapter on PSEG Services Corporation, prior to 2009 most security activities other than guard services were charged under the service "Corporate Security." About 60 percent of this service was allocated to Utility in 2007 and 2008 using an Enterprise allocation method. In 2009, PSEG Services broke Corporate Security into several more targeted services, including Security Command Center and Security Planning and Operations. A significant portion (all except the corporate level) of these services was charged using a method that closely matched the relative numbers of security cameras installed at Power and Utility facilities. Since most cameras are installed at utility facilities, this increased the Utility share of the cost of security planning, operations and command center activities to about 87 percent in 2009.

Business and Infrastructure Security Practices and Coordination with State Governmental Authorities

PSEG works with the BPU and the New Jersey Office of Homeland Security to develop and implement policies that reflect "best security practices." PSEG participated in the development of a utility sector "best practices" manual following September 11, 2001. As of 2010, PSE&G President Ralph LaRossa was Chair of the Energy Sector subcommittee of the New Jersey Infrastructure Advisory Committee and the President of PSEG Power, Bill Levis, served as Chair of the Nuclear Sector subcommittee of the same group.[19]

PSEG maintains a Master Security Plan and a Security Council.[20] The Security Council's responsibilities include acting as an advisor to senior management, identifying emerging security issues, providing input in the implementation of security policies and enhancing security communications. PSEG maintains formal (written) security practices addressing and establishing accountabilities for the following:

- Business Interruption Management
- Crisis Management, which describe procedures for the structure and responsibilities of an Executive Crisis Management Team
- Disaster Recovery
- Emergency Response

Facilities security includes a number of protective measures. In general, these include:

- Policies, procedures and practices (including those described above)
- Physical access controls and badging
- Video and manual surveillance
- Security guards
- Security command center

The command center was implemented after 9/11/2001 to provide centralized, 24/7 security oversight of all critical facilities. PSEG indicated that it was the first utility in the region to implement such a center.[21] During 2010, the company was in the process of improving command center monitoring capabilities and operator efficiency.

PSEG's Business Assurance and Resilience function conducts a security awareness program to reinforce internal security practices. The program is targeted to employees, contractors and vendors to ensure awareness of and compliance with security practices and requirements. Communication methods include email bulletins, training presentations and management support and an intranet site. Subjects covered include information security, employee, contractor and visitor identification, "acceptable use" of PSEG networks and systems, computer protection and responsibilities, reporting lost or stolen

[19] Response to Discovery, OC-432.
[20] Response to Discovery, OC-835.
[21] Response to Discovery, OC-439.

computers and communication devices and information security, sharing and protection, including the use of passwords.[22]

Security and Claims Performance

In 2008 Security and Claims tracked 22 different Client and Operational Scorecard metrics. With a revamped scorecard structure, there were 18 metrics in 2009.[23] Selected metrics used in 2009 are summarized and discussed below.

Table 28-10 – Key Operational Scorecard Metrics

PSEG Security and Claims Key Operational Scorecard Metrics				
Category	2008		2009	
	Target	Achieved	Target	Achieved
Security Operations				
Security Investigation Efficiency Pct	not avail.	88.5	95.0	100.0
Business Continuity Preparedness Pct. - Critical Plans	90.0	96.0	97.0	100.0
Business Continuity Preparedness Pct. - Other Plans	85.0	98.9	99.0	100.0
Crisis Management Preparedness Pct.	not avail.	67.0	91.0	100.0
Command Ctr Response - Undetected Events - Critical	not avail.	None	None	None
Command Ctr Response - Undetected Events - High	not avail.	8.0	7.0	6.0
Claims Operations				
Pct Non-Litigated Claims Closed w /o 3rd Party Payment	75.5	78.0	78.5	83.0
Average Dollars Paid - Non-Litigated Claims ($)	799.0	708.0	700.0	506.0
Financial Recovery - Pct. Of Totals Amts. Recovered	not avail.	83.0	86.0	94.0
Cost of Insurable Risk ($ millions)	not avail.	19.9	21.3	15.2
Source: OC-423				

- Security Investigation Performance – Implementation of Prevention and Corrective Action Plan – Upon publication of an Executive Report or Close-Out Memo, all internal control issues identified in Prevention and Correction Action Plans are tracked for closure by a specified completion date. The 2009 target was 95 percent closed by specified date, rising to 97 percent by 2013. 91 percent was achieved in 2008 and 95 percent was achieved in the first quarter of 2009.

- Business Continuity Preparedness – Measures "readiness" as defined by completion of an annual Business Impact Analysis, maintenance of Service Level Agreements for IT Disaster Recovery. This is calculated as the average business unit rate of completion at the end of each year. 96 percent was achieved for "critical plans" in 2008. The target level was 97 percent in 2009, rising to 100 percent by 2011. 99 percent was achieved for "All Other Plans" (plans other than Critical) in 2008, with an on-going target of 99 percent for 2009 through 2013.

[22] Response to Discovery, OC-836.

[23] 2009 metrics not individually described below include "people" metrics that are not specific to security or claims operations, including the OSHA recordable incidence rate, OSHA days away from work, "employee development" and "enhancement of corporate culture for ethics and compliance."

- Security Command Center Effectiveness – Measures the number of adverse events reported to or discovered by the Security Command Center for all facilities designated as "critical" or "high" in PSEG's Risk Assessment Schedule, and the correct identification, handling and disposition of such events. Targets are 7 or fewer "undetected" events at "high" facilities (falling to 4 or fewer by 2012) and 0 at "critical" facilities for the period 2009-2013. Security realized 8 undetected events at "high" facilities and none at "critical" facilities in 2008.

- Crisis Management Preparedness - Measures the responsiveness of the Executive Crisis Management Team (ECMT) to call outs, tested on a drill basis. It is calculated based on total ECMT responses received within a prescribed time, measured against 8 "core seats" which must be filled. A year-end percentage measures the number of tests and drills passed compared with the total. The 2009 target was to achieve an average 91 percent success in seating all 8 core member positions with a primary, secondary or tertiary member within 20 minutes for each test. Only 67 percent was achieved in 2008. The target was scheduled to rise to 98 percent in 2010 and 100 percent thereafter.

- Percentage of Non-Litigated Claims Closed Without Payment – Measures the percentage of non-litigated claims that can be closed without a payment to a third party. An average of 76.2 percent of approximately 4,400 claims per year was achieved for the five years 2004 through 2008. The target for 2009 was 78.5 percent, rising to 80 percent by 2012.

- Average Dollars Paid per Non-Litigated Claim – A calculation of total non-litigated claim dollars paid, divided by total claims. An average of $795 was realized for the six years 2003 through 2008. The target was set at $700 for the period 2009 through 2012.

- Financial Recovery – Measures the percentage of money recovered for damage to Company property caused by third parties for claims below $500,000. The average recovery for the period 2006 through 2008 was 83 percent. Targets were established at 86 percent for 2009, rising to 90 percent by 2013.

- Cost of Insurable Risk – Measures the cost of insurance purchased externally and incurred internally through changes to reserves, plus "incurred but not reported" costs. A target of $21.3 million was set for 2009; no targets are evident for years after 2009. The cost incurred in was $25.4 million in 2007 and $19.9 million in 2009.

Productivity Enhancements – The claims and security functions underwent an organizational redesign between 2007 and 2009. This reduced full-time positions from 50 to 44.[24] Managers of business interruption management, crisis management and asset protection, as well as Operations Director and Facilities Relocation Manager positions were eliminated. The Vice President of Security's span of control was increased. As shown above, the overall cost was reduced by approximately $3 million between 2007 and 2009.

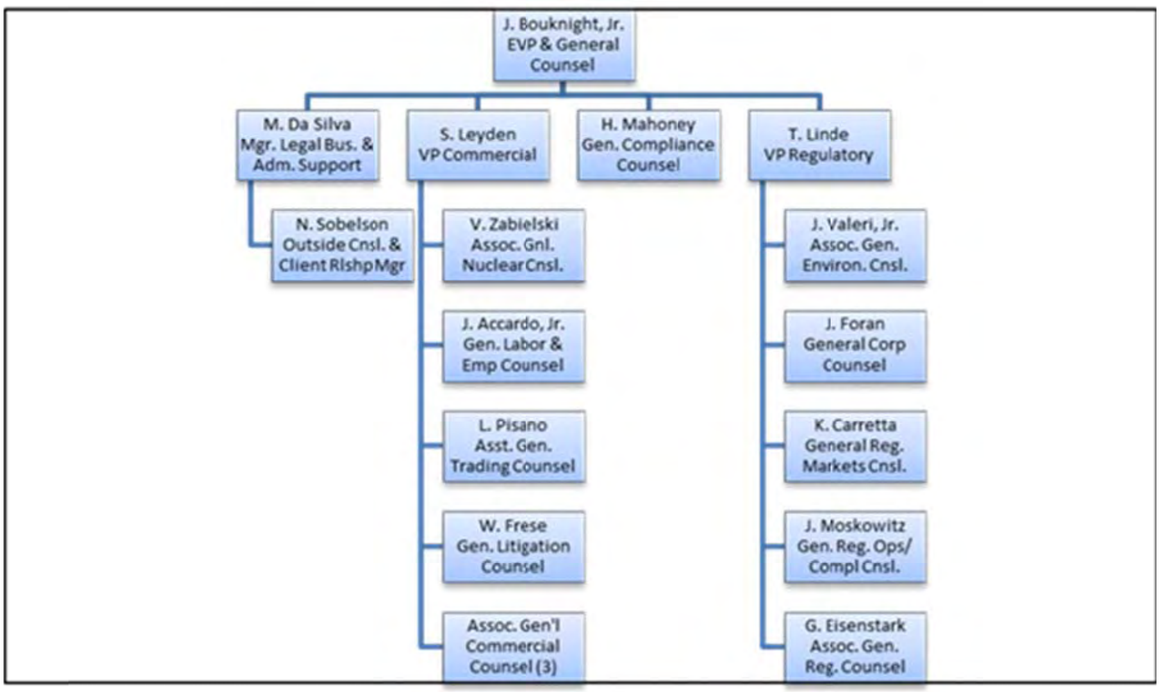
[24] Interview, Libby Price, Manager Projects, Analysis and Systems Support and Frank McCormick, Manager, Asset Protection and Preparedness, June 11, 2010. According to data provided in OC-825, as of April 30, 2010, there were 41 actual FTEs.

Law

Organization

PSEG's Law Department resides organizationally within PSEG Services and, in April 2010, included approximately 60 employees.[25] During most of the review period the Law department was headed by Executive Vice President and General Counsel Edwin Selover. In November, 2009, Mr. Selover was replaced by J.A. Bouknight, Jr. In addition to the Legal function, the Corporate Secretary, State and Federal Government Affairs and Communications and Advertising functions also report to the EVP / General Counsel. Below is an organization chart showing the key reporting relationships in the Legal function as of April, 2010.

Table 28-1 . - PSEG Law Department Organization, April, 2010



PSEG Law includes the following significant organizational divisions:[26]

- Corporate and Commercial has responsibility for commercial transactions. Activities include negotiating, drafting, executing and interpreting transactions and related contracts.
- Energy Trading is responsible for legal issues relating to physical and financial energy trading and energy-related products.

[25] This excludes 12 employees associated with the Corporate Secretary and Records Management and Library functions, which are sometimes classified as part of the Legal function. Response to Discovery, OC-827.
[26] Response to Discovery, OC-73.

- Nuclear is responsible for the gamut of legal issues associated with the nuclear business, including transactions involving equipment, services and fuel, licensing and enforcement, safety and NRC regulatory compliance and related employee issues.
- General Litigation is responsible for litigation matters, including the areas of collection, bankruptcy and property. The General Counsel – Litigation reports to the VP, Commercial.
- Labor and Employment is responsible for matters regulated by federal and state labor and employment laws, providing guidance to the Human Resources function, and representing PSEG on labor matters in court, before agencies, and in mediation and arbitration.
- Regulatory is responsible for state and federal regulatory matters, including compliance with laws, regulations and approvals. The group represents the PSEG companies before regulatory agencies, including the FERC and the New Jersey BPU.
- General Compliance – During 2010, Hugh Mahoney, General Compliance Counsel reported directly to EVP and General Counsel J. Bouknight. This function conducts compliance activities primarily in the areas of corporate governance, ethics and code of conduct.
- Business and Administrative Support – This group includes approximately a dozen employees. In 2010 it was headed by Maria DaSilva, Manager, Legal Business and Administrative Support and it is responsible for management and administration of the legal function. In effect, it represents a miniature service company for the legal function. Responsibilities include business planning and performance, financial management and reporting, information technology needs, legal and organizational and employee development and oversight of external legal providers.

Costs and Cost Distributions

As shown in the table below, Law Department costs were steady during the 2007-2009 review period, with a 20 percent spike in 2008 due primarily to some corporate transactions that occurred during that year.

Table 28-12 – Law Department Costs

PSEG Services Cost Distr butions Law ($000s)						
Segment	2007		2008		2009	
	Amount	Pct	Amount	Pct	Amount	Pct
Enterprise	138	1%	152	1%	17	0%
Holdings	1,775	8%	5,474	20%	2,116	9%
Pow er	9,047	40%	9,098	33%	8,353	36%
Utility	11,812	52%	12,797	47%	12,821	55%
Total	$22,772	100%	$27,521	100%	$23,307	100%
Source: OC-554						

The legal function of the Corporate Rate Counsel department has been shifted to a new rates group within the Law Department's regulatory group. The position of Vice President and Corporate Rate Counsel is being eliminated. One full-time attorney position and one contract attorney position have been transferred to the Law Department. The reorganization has already begun and will be complete by the end of 2010.[27]

The expected benefits of the reorganization are cost savings and more efficient, coordinated legal services regarding rate issues for both PSE&G and the other PSEG companies.[28]

For cost tracking purposes, PSEG divides the Law Department into service lines which correspond generally with the organizational breakdown shown above. Law Department charges by service line to the individual operating companies for the review period 2007 to 2009 are summarized below.

Table 28-13 – Cost Distributions to Operating Companies by Service Line

PSEG Law Department Cost Distr butions to Operating Companies by Service Line 2007-2009 Combined ($000s)					
Service Line	Enterprise	Holdings	Power	Utility	Total
Commercial		3,434	4,364	1,559	9,356
Compliance		212	1,270	2,257	3,739
Corp. & Financial Transactions	307	3,232	3,849	4,459	11,847
Corporate Development		545	13	93	650
Environmental		163	5,996	3,413	9,571
Energy Resources / Trading			829	89	918
Government Affairs			28	46	74
Labor & Employment		67	1,731	3,747	5,545
Litigation		1,264	2,762	10,768	14,794
Preventative Law		19	110	193	322
Property		5	82	2,345	2,432
Regulatory		425	5,464	8,463	14,351
Grand Total	307	9,364	26,498	37,430	73,599
Percentages	<1%	13%	36%	51%	100%
Source: OC-554					

Performance

PSEG participates in the Hildebrandt Law Department benchmarking survey. In 2008 this survey included 26 participants in the Energy and Utilities subgroup. The most important cost efficiency statistics in this survey are legal spending as a percentage of revenue and spending "per lawyer." As shown below, in terms of Law Department cost efficiency, PSEG scored well against the benchmarks in the two years we reviewed.

[27] Response to Discovery, OC-1158.
[28] Ibid.

Table 28-14 – Key Spending Benchmarks per Hildebrandt Law Survey

PSEG Legal Spending Key Spending Benchmarks per Hildebrandt Law Survey Energy and Utility Company Sub-Group				
	2007		2008	
Category	PSEG	Median	PSEG	Median
Total Legal Spend (1)				
Total Legal Spending	$30.4M	$34.3M	$28.7M	$32.6M
Pct. Of U.S. Revenue	0.24%	0.43%	0.22%	0.39%
Total Legal Spend per Lawyer	$779K	$1.1M	$759K	$1.0M
Inside Legal Spend (1)				
Total Inside Legal Spend	$18.1M	$15.8M	$17.3M	$15.3M
Pct. Of U.S. Revenue	0.14%	0.17%	0.13%	0.15%
Inside Legal Spend per Lawyer	$463K	$404K	$459K	$420K
Outside Legal Spend (1)				
Total Outside Legal Spend	$12.3M	$17.6M	$11.3M	$17.2M
Pct. Of U.S. Revenue	0.10%	0.19%	0.09%	0.23%
Outside Legal Spend per Lawyer	$316K	$638K	$300K	$592K
(1) U.S. Spend (about 90% of PSEG's Legal Spend per Hildebrandt)				
Source: OC-57 / OC-414				

As a percentage of revenue, PSEG's total legal spending was only a little more than half that of the Energy and Utility group median. Overall legal spending was 70 percent of median of companies in the group; however, PSEG is larger than the average company in the Energy and Utility survey group.

Outside Legal Cost Management - A primary reason for PSEG's favorable cost performance relative to the Hildebrandt benchmark group is its management of the distribution of work (and spending) between inside and outside attorneys. In comparison with the benchmark group, PSEG's inside legal costs are more expensive on a "per lawyer" basis in comparison with the benchmark group.[29] However, spending on outside attorneys, on a "per lawyer" basis and "percentage of revenue" basis, is significantly below (about one-half) the median outside spending per lawyer incurred in the Energy and Utility group of companies for survey years 2007 and 2008. Overall, this translates to total spending as a percentage of revenue that is significantly below the median for the energy and utility companies in the survey.

A key element of PSEG's control of outside legal spending is the competitive procurement process, implemented in 2007.[30] PSEG currently employs an Outside Counsel and Client Relationship Manager. A significant part of the responsibility of this position is to implement competitive bidding and manage relationships with outside legal providers, including attorneys and, occasionally, other experts. The Law Department selects a core group of outside providers for a three-year period. Core providers are selected by a team, which applies a system of quantitative and qualitative criteria to rate service providers. In many cases, service providers are asked to provide their best hourly rates.

[29] Part of this may be explained by the fact that PSEG is a somewhat larger company than the median in the Hildebrandt Energy and Utility survey group, and it is located on the east coast in the vicinity of New York, where labor costs tend to be somewhat higher than the U.S. average. PSEG's average attorney may also be more experienced, and therefore somewhat more expensive, than the average attorney in the median survey utility. Finally, PSEG may have a higher ratio of support staff (paralegals and administrative staff) to attorneys than other utilities in the survey group.

[30] Interview, Maria DeSilva and Nancy Sobelson, June 10, 2010.

A review of outside legal spending for the years 2007 through 2009 shows that PSEG does not rely, as do some utilities that Overland has observed, on a small number of outside legal counsel relationships and providers.[31] During the review period PSEG utilized dozens of different law firms, and spending per firm seldom exceeded $1 million in a given year. Additionally, the few firms with the highest billings in one year did not have the highest billings in the next. This is consistent with a competitive, rather than a relationship-driven procurement process.

Productivity Enhancements[32] – The Law Department utilizes a legal matter-based time and cost management system known as Team Connect to record time and manage cases. When new matters are identified, they are set up in the system and, to the extent possible, the client (operating company) or clients owning the matter are identified. Team Connect links with Enterprise Content Management, a document management system. The Law Department recently implemented electronic invoicing (e-billing) for outside legal provider invoices. E-billing is integrated with Team Connect. At the time of Overland's interview in mid-2010, e-billing was in the process of being interfaced with SAP. When implemented this is expected to reduce manual keying, manual process intervention and overall paperwork.[33] One of the department's long run objectives is to eliminate paper billing whenever possible.

As of 2010, the paper Law Library, consisting of books and binders, was becoming extinct. Employees no longer pull binders and books apart to insert updates. Instead, the department relies primarily on Westlaw for reference needs, with which PSEG recently negotiated a multi-year, fixed-rate contract. The Company uses a document management application that permits the identification and filing of all electronic documents associated with a case, helping to eliminate the need to compile paper files.[34]

Performance Measurement – The Law Department uses a number of standard metrics to track employee productivity. Many of these are applicable to the service company as a whole, and the Law Department's general targets are consistent with those of the larger service company. It appears that Law met or exceeded most of its department-specific metrics for which measurements were taken in 2008 and 2009. Significant department-specific scorecard metrics during the review period included the following:[35]

- Reliability of Legal Advice – This is measured by comparing actual settlement, arbitration or court outcomes to legal reserves. It is calculated as the aggregate cost of all dispositions as a percentage of reserves. The target is 100 percent (reserves accurately reflect dispositions). In 2008 dispositions were 106 percent of reserves. In 2009, using a "new methodology," dispositions were 75 percent of reserves, significantly exceeding the 100 percent target.

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[31] Response to Discovery, OC-834.
[32] Interview, Maria DaSilva and Nancy Sobelson, June 10, 2010.
[33] The interface between legal case management and SAP was imminent at the time of our interview in June, 2010.
[34] Interview, Maria DeSilva and Nancy Sobelson, June 10, 2010.
[35] Response to Discovery, OC-406 and OC-422.

- Compliance Matters Cycle Time – This metric is intended to measure the efficiency with which compliance-related legal work is conducted. It is calculated as the percentage of matters opened in the compliance data system that are closed within 80 days and the percentage of "prevention and correction recommendations" implemented with "timeframes established in incident report". The target for this metric is 80 percent. Actual 2008 performance was 72 percent. Actual 2009 performance was 92 percent, suggesting the target may have been set a little low.

- Staffing Ratio – The objective of this metric is to reduce the ratio of support staff to attorneys by increasing support staff productivity. It is measured as the ratio of non-lawyers to lawyers. In 2008 the ratio was 78 percent. The 2009 target was 76 percent and a 75 percent ratio was achieved.

- Controllable O&M – This is defined as the "impact to earnings, modified at the practice area (legal function) level to include practice area pool billing." The Legal practice area exceeded targets in 2008 and 2009.

- Outside Counsel Spend Index – This is a measurement of outside counsel spending as a percentage of Enterprise revenues. Targets were 0.09 percent in 2008 and 0.13 percent in 2009. The department achieved the target in 2008 and significantly exceeded the target in 2009, coming in at 0.06 percent of revenue.

- Inside Legal Spend – The objective is to achieve a "sustained ratio of 50 percent" of internal to total spend over time. Lower is considered better.[36] Internal spend was 56 percent in 2008 and 67 percent in 2009. It is unclear to Overland why it is necessarily desirable to target a 50 percent ratio for internal to total legal spend.

- Total Legal Spend – This metric targets total legal spending as a percentage of Enterprise revenue. The target in 2009 was 0.22 percent. The department achieved 0.23 percent in 2008 and 0.18 percent in 2009.

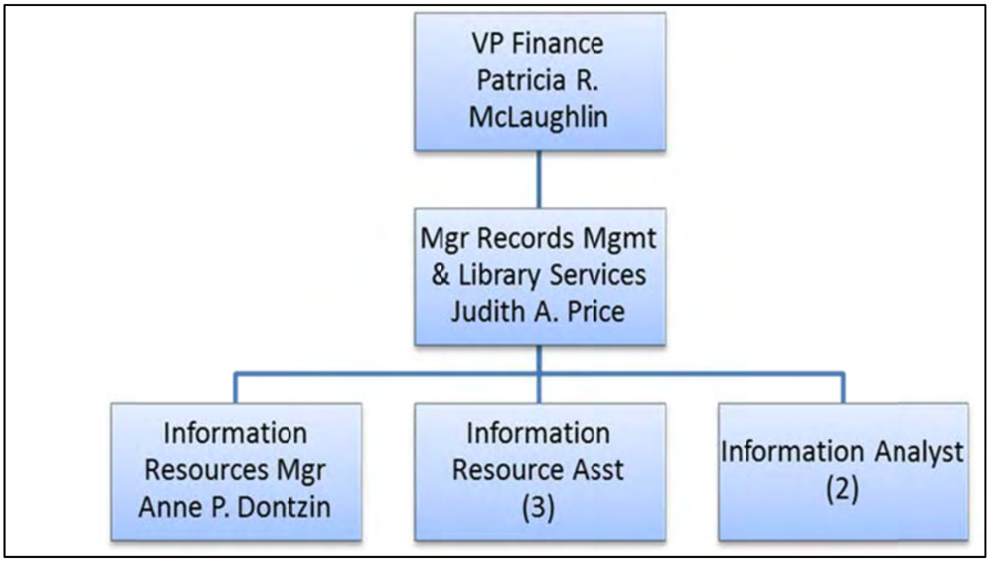
Corporate Records and Library

Organization

The Records and Library function resides within PSEG Services Corporation and is a Practice Area within the service company. As summarized below, in 2010 the organization was headed by Judith Price, Manager, Records Management and Library Services and consisted of seven employees. During the 2007-2009 review period Ms. Price reported to Patricia McLaughlin, VP of Finance for the service company.

[36] Of course, a lower percentage of internal to total spend means a higher ratio of outside to total spend, which is not necessarily desirable.

Table 28-1 ; - PSEG Record ; and Library Organization, April 2010



Functional Responsibilities

The Records and Library organization coordinates records management practices for PSEG and its operatin ; companies. It has the following records management responsi ilities.[37]

- Publish and maintain Enterprise records retention schedules (Enterprise Practice 105-1-1)
- Provide guida ıce on use and interpretation of the E ıterprise sch ːdule
- Establish reco ʼd retention guidelines
- Develop department retention schedules for specific operations (Enterprise Practice 105-1-2)
- Assist with re :ords retention compliance
- Document record suspension and destruction
- Ensure records storage and destruction in accordance with requi ʼements

Records retention policies are reviewed and approved by th ː Law Depart ment. The library responsi ilities of the function include managing subscriptions to external content, managing databases and maintaining a libr ıry of records that include videos, boo ‹s, historical information and safety information.[38]

Records ınd Library h ıs a number of policies designed to en ;ure the pro ıer management and retention of records, and access to information.[39] Records and electronically store ɪ information are defined. An Office of Record and I ıformation Owners are assigned to en ;ure a conne :tion between records and the

[37] Response to Discovery, OC-434.
[38] Interview, Judith Price, Manager – Records and Library Servic ·s, June 9, 2010.
[39] Response to Discovery, OC-434.

responsibility for their retention and eventual destruction. PSEG maintains the following policies associated with the function:

- Information Management "Policy 9" – This states that PSEG will identify, manage and retain records and information required to conduct business and to ensure consistent and documented retention and destruction in compliance with legal and regulatory requirements. It contains implementation steps to accomplish this. It vests overall responsibility for implementation, administration, monitoring and maintenance of the policy in the President of PSEG Services Corporation and references the Enterprise practices described below.

- Enterprise Practice 105-1 (Records Management) – This policy contains the definitions of corporate records, record copies, titles and office of record. It documents a records management framework, which includes records identification, retention, storage and destruction. It assigns various responsibilities to the Records Management & Library, Law and Internal Audit functions and notes that the Corporate Secretary of PSEG "has overall responsibility for the records of the Corporation," while "the Vice President and General Counsel of PSEG is responsible for interpretation of this practice."

- Enterprise Practice 105-1-1 (Retention Schedule) – This policy provides retention guidelines and references a records retention schedule applicable to individual departments. Guidelines include the content of the retention schedule (record titles, approve periods, legal and regulatory requirement references, Office of Record, Information Owner and information security classification.)

- Enterprise Practice 105-1-2 (Departmental Records Retention Schedules) – This practice helps define and separate the responsibilities of departments from the Records Management and Library function and the Law and Internal Audit functions.

- Enterprise Practice 105-1-3 (Use of Offsite Storage) – This practice provides standards and instructions for the transfer of records to offsite storage.

Costs and Cost Distributions

The table below summarizes the distribution of these costs for the period 2007-2009.

Table 28-16 – Cost Distributions to Operating Companies by Service

PSEG Records & L brary Services Cost Distributions to Operating Companies by Service 2007-2009 ($000s)						
	2007		2008		2009	
	Amount	Pct.	Amount	Pct.	Amount	Pct.
Holdings	58	4%	101	4%	110	5%
Pow er	524	39%	1,108	44%	997	48%
Utility	751	56%	1,307	52%	985	47%
Total	1,333	100%	2,516	100%	2,092	100%
Source: OC-554						

Records and Library costs are grouped into essentially two "services": the cost of acquiring external content, either on behalf of the Enterprise as a whole, or on behalf of a specific operating company, and the cost of professional services provided by Records and Library employees to carry out the functional responsibilities listed above – again, either on behalf of the Enterprise as a whole, or for a specific operating company.

Table 28-17 – Cost Distributions to Operating Companies by Service

PSEG Records & L brary Services Cost Distributions to Operating Companies by Service 2007-2009 Combined ($000s)				
Service	Holdings	Pow er	Utility	Total
Information Management - Enterprise	72	1,298	1,924	3,294
Information Management - Client-Specific	84	150	45	279
Subtotal Information Services	156	1,448	1,969	3,573
Subscription Services - Enterprise	22	423	627	1,072
Subscription Services - Client-Specific	91	758	448	1,297
Subtotal Subscription Services	113	1,181	1,075	2,369
Total	269	2,629	3,044	5,942
Percentages	4.5%	44.2%	51.2%	100.0%
Source: OC-554				

Performance

Although the Manager Records and Library reports to a Finance Vice President, and although it is a separate service company practice area, the function is grouped with the Law Department for budget and performance evaluation purposes. There are no metrics associated with Records and Library function in the 2008 Law Department Balanced Scorecard. However, in 2009, the Law Department has one metric associated with the Library function: Library Services Cost per Client Contact.[40] The function achieved a level of $25.58 per contact in 2008. It set a target of $23.00 for 2009 and achieved $21.02.

[40] Response to Discovery, OC-422.

Referencing the table above, it can be seen that total costs for the function declined from $2.5 million in 2008 to $2.1 million in 2009, which probably explains the decline in cost per contact between 2008 and 2009.

Fleet Management

The Fleet Maintenance business unit oversees the acquisition, maintenance, disposal, and administration of PSE&G's fleet of vehicles. As of June 2010, the business unit was headed by Rick Buro, Manager of Transportation and Equipment.

As of April 2010, PSE&G owned and operated a fleet of 5,685 vehicles for the utility. This includes vehicles (cars, SUVs, light to heavy duty pickup trucks, bucket trucks, and digger trucks), trailers, and power operated equipment (forklifts, backhoes, and trenchers).[41]

Table 28-18 – Fleet Profile

Public Service Electric and Gas Fleet Profile				
Types of Unit	**2006**	**2007**	**2008**	**April 2010**
Vehicles	4,634	4,624	4,748	4,496
Power Operated Equip.	337	358	364	309
Trailers	608	616	681	751
Other	99	104	106	129
Total	**5,678**	**5,702**	**5,899**	**5,685**
Source: Fleet Benchmarking Studies, OC-421 and Response to Discovery, OC-837 and OC-918				

There are an additional 577 vehicles that are managed and operated by other affiliates, mostly PSEG Power.[42] The utility generally does not perform maintenance on the non-utility vehicles. PSE&G does process various types of paper work for the non-utility vehicles. Any work done on non-utility vehicles is directly billed to the affiliated entity by the utility.[43]

Transportation Organization and Operations

Organization – As of April 2010, the Fleet Maintenance business unit consisted of 213 employees.[44] The business unit is headed by the Manager of Transportation and Equipment who is responsible for managing and directing the fleet operations (acquisition, maintenance, disposal, and administration) as well as planning, budgeting, and performance objectives.

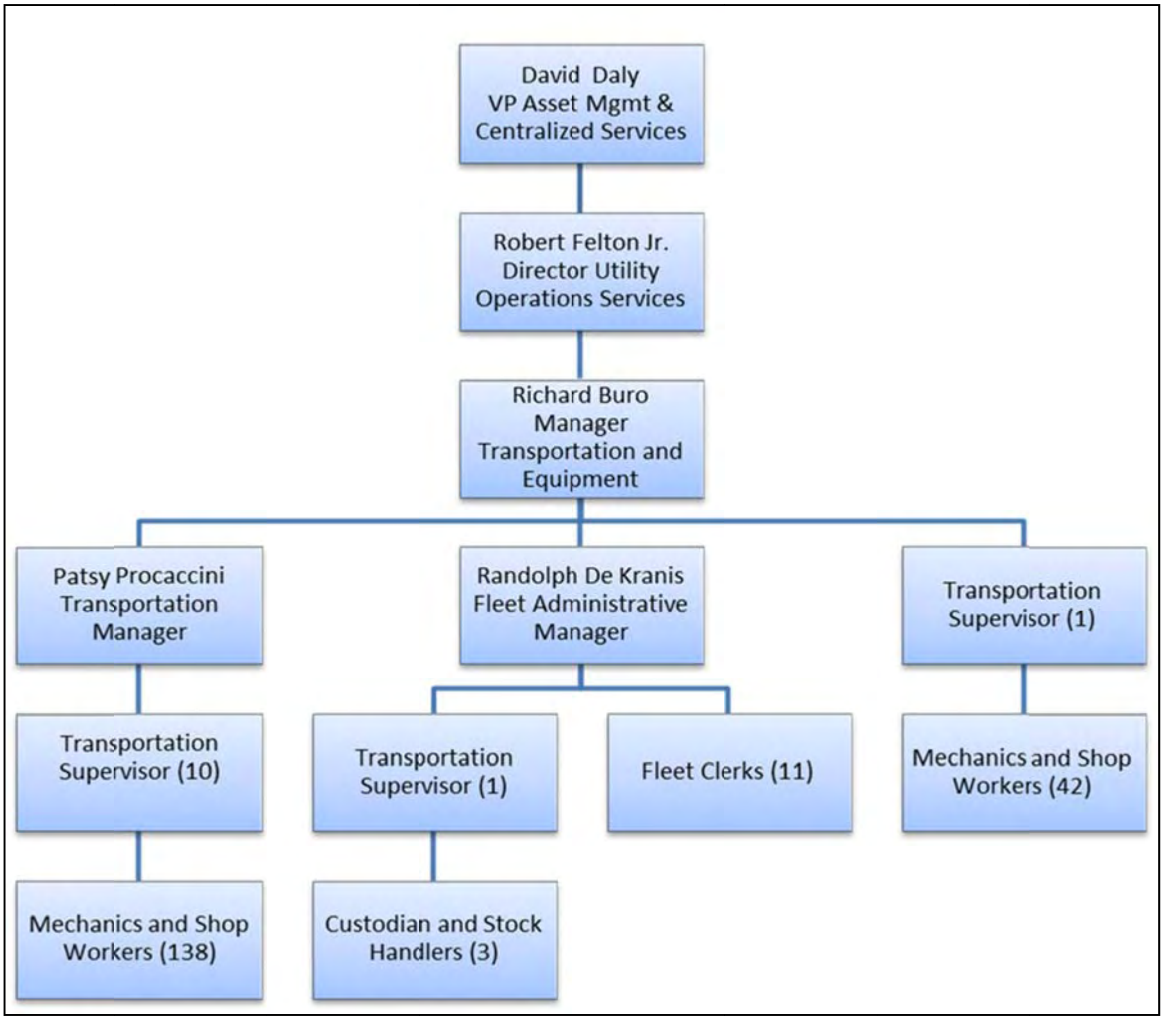
[41] Response to Discovery, OC-837.
[42] Ibid.
[43] Based on interview with Rick Buro, Manager of Transportation and Equipment, June 9, 2010.
[44] Response to Discovery, OC-823.

There are seven employees that report to the Manager of Transportation and Equipment. There is a Transportation Manager that is responsible for fleet operations in the field, at the 22 different fleet locations and at the headquarters in Newark. There is a Fleet Administrative Manager who is responsible for licensing, registration, inputting fleet information into SAP, and the paperwork associated with fleet acquisition and disposal. There are two specification and design employees whose titles are Auto Training Specialist and Equipment Design Supervisor. One is assigned to work with the electric fleet while the other is assigned to work with the gas fleet. These employees work closely with the Procurement division in dealing with purchasing parts and vehicles for the fleet. They also work with internal customers to determine which vehicles meet replacement criteria as well as interact with the other Operations groups within the utility when other Fleet related topics arise. They are also in contact with outside vendors to stay current on the latest products and services. There is a Transportation Supervisor who is responsible for the garage operation in Edison, NJ. There is a Fleet Analyst who is responsible for budgeting, reporting, analysis, and special projects for the business unit.[45]

Below the employees mentioned in the previous paragraph are transportation supervisors, fleet clerks, custodian and stock handlers, and mechanics and shop workers. The general layout of the organization is summarized in the chart below.[46]

[45] Based on interview with Rick Buro, Manager of Transportation and Equipment, June 9, 2010
[46] Derived from Response to Discovery, OC-823.

Table 28-1) – Transportation Organization Chart



Transportation Budget – The table below summarizes PSE&G's fleet costs for 2006 through 2008.

Table 28-20 – Fleet Management Expenses

Public Service Electric & Gas Fleet Management Expenses			
Category	**2006**	**2007**	**2008**
Lease	-	-	-
Interest	5,231,041	5,047,804	3,699,580
Depreciation	19,018,078	16,606,126	18,075,075
Licensing	1,265,653	1,300,210	1,348,817
Ownership Cost	25,514,772	22,954,140	23,123,472
Mechanic	15,373,305	15,698,954	15,994,039
Contract	1,010,223	1,080,940	1,143,769
Parts	8,103,238	8,909,102	9,507,184
Fuel	10,218,063	10,375,231	16,137,634
Operating Cost	34,704,829	36,064,227	42,782,626
Support Labor	4,837,067	4,947,909	5,527,063
Other Support Cost	-	-	264,008
Support Cost	4,837,067	4,947,909	5,791,071
Total Fleet Cost	**65,056,668**	**63,966,276**	**71,697,169**
Source: Utilimarc Benchmark Study, Response to Discovery, OC-421			

Repairs and Maintenance – PSE&G has 23 locations in the field where repairs and maintenance take place, including the Edison location where the Fleet is headquartered.

These locations have approximately 180 mechanics and shop workers, with approximately 40 of these workers being at the Edison location.[47] PSE&G performs substantially all of the maintenance and repairs of its vehicles internally. The only major exception to this practice is warranty repairs.

Vehicle Administration

SAP is the key information system that is used to administer the various functions of the Fleet Maintenance business unit. Before Fleet began to use SAP in the late 1990s, the business unit used a dedicated Fleet Management system. Currently, they have converted a Work Management module from SAP into an application that includes asset tracking, preventative maintenance schedules, and meter points (mileage). At the time of this audit, Fleet is in the process of implementing a fuel management system, which is scheduled to be completed in November 2010. This system will have the

[47] Response to Discovery, OC-823.

ability to determine the vehicle operator, the fuel requirements of the vehicle, and other diagnostic information relating to the use and maintenance of the vehicle.[48]

Utilimarc Benchmark Study

Utilimarc, a consultant that specializes in utility industry fleet operations, performed benchmarking of PSE&G's Fleet business unit in 2005 – 2008. The table below summarizes key statistics for PSE&G in 2008, compared with the averages for all of the utilities in a group of 46 utility holding company study participants.

Table 28-21 – Key Fleet Benchmarks - 2008

Public Service Electric & Gas Key Fleet Benchmarks - 2008		
Benchmarks	**PSE&G**	**Participant Average**
Average Age Vehicles	6.1	5.6
Average Age Trailers	13.7	13.9
Average Age Power Op Units	8.3	10.3
Maint/Repair Hrs per Mechanic	1497	2452
Maint/Repair Hrs per Support Employee	4462	6232
Units per Mechanic	36.98	54.17
Units per Support Employee	110	137
Customers per Unit	N/A	713
Total Annual Cost per Vehicle	$13,639	$18,363
Total Annual Cost per Trailer	$2,876	$2,965
Total Annual cost per Power Op Unit	$11,796	$9,549
Cost per Retail Customer	N/A	22.84
Source: Utilimarc 2008 Fleet Benchmark, Response to Discovery, OC-421		

The study shows that PSE&G's 2008 cost per vehicle was significantly lower than the benchmark study participant average. This is due to PSE&G owning a higher number of vans than the participant average. PSE&G has a large fleet of vans due to their appliance service business unit. These vehicles generally cost less to maintain than heavier duty vehicles.

Balanced Scorecard

The Fleet business unit maintains a balanced scorecard to track the performance of the business unit against goals set at the beginning of each year. The 2009 balanced scorecard for Fleet is summarized in the table below:

[48] Based on interview with Rick Buro, Manager of Transportation and Equipment, June 9, 2010.

Table 28-22 – 2009 Fleet Balanced Scorecard

Public Service Electric & Gas 2009 Fleet Balanced Scorecard			
Metrics	2009 Benchmark	2008 Actual	2009 Actual
OSHA Recordable Incident Rate	1 39	0	0.97
OSHA Days Away Rate	6 96	0	24.81
Motor Vehicle Accident Rate	3.76	11.5	7.4
Availability - Illness	97.3%	96.1%	96.4%
Overtime	12.0%	11.0%	8.0%
Staffing Levels - Permanent	214	213	214
Employee Development - MAST*	0 95	N/A	1
Employee Technical Training - BU	1	N/A	1
PM Compliance	99.0%	99 3%	99.7%
Fix it Right	96.0%	97 9%	98.1%
Mean Time Between Service (Days)	39.7	39.6	41.8
Training Hrs.	1,416	5,103	10,944
Maint./Repair Cost per MRU**	1,898	1,816	1,897
Total CapEx	11.9	0.3	12.5
Accountability O&M	16.7	15	15.6
Incurred Budget	34 3	34.1	33.7
Fleet Miles per Gallon	8.85	8.84	8.88

Source: Response to Discovery OC-429
* Management, Administrative, Supervisory and Technical. This describes PSEG's non-union employees, per Response to Discovery, OC-1502.
** Maintenance Repair Unit

The only significant variance between the 2009 benchmark and the 2009 actual amount is the training hours. The training hours significantly increased due to increased original equipment manufacturer (OEM) training for aerial lifts and digger derricks.[49]

During the interview with Rick Buro, Manager of Transportation and Equipment, he discussed with Overland that his performance evaluation is linked with the business unit's scorecard. He specifically cited having performance goals in the area of preventative maintenance (PM) compliance and the implementation and/or improvement in certain Fleet initiatives such as: Fix-It-Right, fleet utilization initiative, and Fuel Management System.[50]

[49] Ibid.
[50] Ibid.

Fleet Management Initiatives

The Fleet business unit has implemented some strategic initiatives that have proved to both enhance the productivity of the business unit and reduce the cost of managing the fleet. Below is a brief summary of the major initiatives taking place in the Fleet Management business unit at the time of our audit.[51]

- Right Sized Fleet – This initiative reviewed the policy for certain employees having a company vehicle (based on job responsibility) and determined that the assignment of company vehicles to certain employees was no longer necessary. The result of this initiative reduced the fleet of vehicles by approximately 200 in 2009.
- Fuel Hedging – In 2010, PSE&G worked with Procurement to hedge half of the expected fuel to be purchased during the year at a cost of $2.10 per gallon through Petroleum Traders, a fuel broker. As of July 1, 2010, Fleet had achieved savings of $94,456 using this initiative.
- Parts Supply – PSE&G Fleet has a consignment contract with parts dealer Parts Distributor, Inc. This contract was awarded to PDI after a bidding process was undertaken by the business unit. PDI stocks parts for PSE&G garage locations and the utility pays for the parts when they are used. PDI monitors the usage of inventory at each of the utility's locations and delivers an amount of parts that should be used in a 30 day time period. Costly and infrequently used parts are ordered as needed. This has helped reduce parts inventories to around $60,000.
- Fuel Efficiency – The Fleet business unit is aggressive in their approach to increasing their fuel efficiency and using renewable energy to power their vehicles. PSE&G has been using biodiesel since 2003 and has a substantial number of hybrid SUVs, hybrid bucket trucks, and electric drive bucket trucks.
- Hiring Experienced Mechanics – PSE&G has negotiated with the governing unions to allow the utility to bring in experienced mechanics that have their certification as Master Technicians. This has helped reduce training time and increased operational efficiencies.

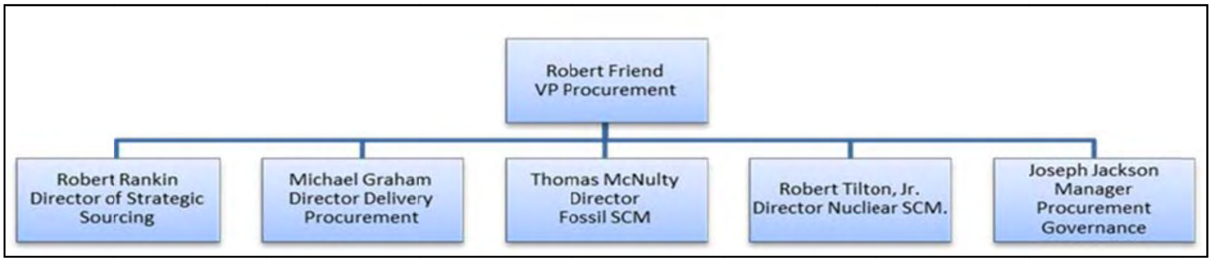
PSE&G's Fleet Management division plans to implement a Fuel Management System by November 2010. This system will be installed at the utility's fueling stations and will have the ability to determine the employee who is using the vehicle as well as the diagnostic information on the vehicle itself. This system will help the business unit better track maintenance schedules for the vehicle and also determine the time for replacement of the vehicle.[52]

[51] Ibid.
[52] Ibid.

Supply Chain

Organization

Table 28-23 – Supply Chain Organization Chart



The Supply Chain (Corporate Procurement) Division is headed by Robert Friend, VP Procurement. Mr. Friend reports to the Executive Vice President and Chief Financial Officer, Caroline Dorsa.[53] As of April 2010, this organization has 96 employees (positions) divided among the following groups:

- Strategic Sourcing (29 employees) – This group evaluates the supply market to determine the purchasing strategy that will be used for the major components of assigned spending categories and to identify qualified vendors.[54] Leading this group is a Director of Strategic Sourcing. Under the director, there are six Category Managers, which plan the strategic spending for their assigned spend category, implement the plan, and manage the results for the category.[55]
- Supply Chain Management (9, 16, and 29 employees for Delivery, Fossil, and Nuclear, respectively) – The Supply Chain Management for the business units in the utility is responsible for various procurement processes, warehouse and materials management, contract development, and supplier management.[56]
- Supply Chain Governance (11 employees) – This group sets guidelines and controls and ensures their compliance in the following areas: Standards of Integrity and Business Compliance, Delegation of Authority for Purchase Requisitions and Purchase Orders, Segregation of Duties, Federal and State Statutory and Regulatory Compliance, and Sarbanes-Oxley Control Compliance.[57]

In 2003, the Supply Chain organization engaged the services of consulting firm Booz Allen Hamilton to assess the current Supply Chain function and construct a strategy to improve future performance.[58] Following the engagement, PSE&G implemented a couple of key changes to its Supply Chain function. The Strategic Sourcing group was formed. Also, the head of the Supply Chain function was elevated to a

[53] Response to Discovery OC-830.
[54] Response to Discovery OC-840.
[55] Response to Discovery OC-73.
[56] Response to Discovery OC-840.
[57] Derived from response to Discovery OC-840. Note: The sum of all the positions described in the bullet points is 94. There is one vacant position at the time of this audit and the 96th position is represented by Robert Friend, Vice President of Procurement who oversees each group.
[58] Response to Discovery, OC-913.

VP position to make the position more visible in the company and to better implement the changes necessary to improve the function.[59]

PSE&G created the Strategic Sourcing function in 2004 in order to gain more leverage in the marketplace. The function did this by implementing a couple of different initiatives. First, Strategic Sourcing created spend categories (approximately 70 primary and 140 secondary categories) for the entire organization in order to obtain the best price in the marketplace for all business units. Second, Strategic Sourcing implemented an integrated procurement strategy where the function determined how inputs (i.e. hardware, software, and maintenance on personal computers) were being used and grouped these inputs together to take advantage of low price options and package options to reduce the overall cost of the bundled purchase.

PSE&G's Supply Chain business unit utilizes a cyclical bidding process for each of its spend categories. Approximately, one-third of the total procurement spend categories are subjected to the bidding process each year. Each category goes through the bidding process every three years. The major products that are purchased for the utility are: maintenance and repair operating equipment (MRO), cable and wire, and transformers.

The Supply Chain function uses several different technology platforms to carry out its objectives: SAP, FileNet, Power Advocate, Spend Intelligence, and Cost Intelligence. SAP is utilized to identify demand, ensure requests are approved, manage inventory, and process purchase orders and receipts. The FileNet system is used to facilitate and support the Contract Review process for supply chain contracts. The review process mostly takes place in the Legal, Risk Management, Accounting, and Tax functions of PSEG. Power Advocate is used in two different ways. First, it contains an electronic request for proposal/quote system that sends and receives RFPs, along with comparative bid evaluation templates. Second, its Cost Indices system tracks the cost fluctuation of key material commodities and commonly used assemblies. Spend Intelligence enables PSEG to perform e-Auctions and electronic RFPs. Cost Intelligence provides supply market cost trends on equipment, components, materials, and service.[60]

The Supply Chain Division interacts with other groups within the utility and outside of the utility. Within the utility, the Supply Chain Division coordinates its purchasing with engineers to ensure that the technical requirements of a product or service are met. The division also coordinates with the risk and legal departments for any type of insurance that may be necessary. The division shares information with outside groups for benchmarking purposes and sharing best practices. UPMG, Platts, Center for Advanced Purchasing Studies (CAPS), American Gas Association, and trade publications are some of the organizations that the division has exchanged information with.

[59] Ibid.
[60] Response to Discovery, OC-914.

Management Cost and Cost Distributions

As shown in the table below, Supply Chain Management costs increased slightly during the 2007-2009 review period, with a 20 percent spike in 2008 due primarily to some corporate transactions that occurred during that year.

Table 28-24 – Cost Distributions to Operating Companies by Service Line

PSEG Supply Chain Management Cost Distributions to Operating Companies by Service Line 2007-2009 Combined						
	2007		2008		2009	
Company	Amount	Percentage	Amount	Percentage	Amount	Percentage
Holdings	$0	0%	$0	0%	$4,171	0%
Power	$7,804,487	70%	$9,518,086	71%	$10,243,397	69%
Utility	$3,383,353	30%	$3,947,769	29%	$4,630,313	31%
Grand Total	**$11,187,840**	**100%**	**$13,465,855**	**100%**	**$14,877,881**	**100%**
Source: Derived from OC-554						

For cost tracking purposes, PSEG divides the Supply Chain Management group into service lines which correspond generally with the organizational breakdown shown above. Supply Chain Management charges by service line to the individual operating companies for the review period 2007 to 2009 are summarized below.

Table 28-25 – Cost Distributions to Operating Companies by Service Line

PSEG Supply Chain Management Cost Distributions to Operating Companies by Service Line 2007-2009 Combined				
Service Line	Holdings	Power	Utility	Grand Total
Excellence & Enterprise Logistics		$4,078,547	$3,311,075	$7,389,622
Mgmt/Strategic Sourcing	$4,171	$1,610,487	$612,303	$2,226,961
Spend Management & Procurement Operations		$20,349,326	$7,516,994	$27,866,320
Spend Management & Procurement Ops		$1,527,610	$521,063	$2,048,673
Grand Total	**$4,171**	**$27,565,970**	**$11,961,435**	**$39,531,576**
Percentages	**0.01%**	**69.73%**	**30.26%**	**100.00%**
Source: Derived from OC-554				

Business Planning and Performance Measurement – The 2009 balanced scorecard actual results and associated targets are summarized in the following table.[61]

Table 28-26 – 2008 Balanced Scorecard

Supply Chain Division 2009 Balanced Scorecard				
Metric	**2009 Target**	**2007**	**2008**	**2009**
People				
OSHA Recordable Incidence Rate	0	0	0	0
OSHA Days Away Rate (Severity)	0	0	0	0
Employee Development - MAST (%)	92%	N/A	74%	91%
Total Vehicle Accidents	0	N/A	0	1
Training/Professional Development	80	N/A	N/A	91
Enhancement of Corporate Culture for Ethics and Compliance	68	N/A	62	77
Safe, Reliable				
SOX Test Failures	3	0	1	3
Material Availability Index - Utility	99.5	99.8	99.7	99.8
Inventory Levels - Utility	63.9	N/A	62.5	67.1
SCM Customer Satisfaction	5.5	N/A	5.3	4.9
Economic				
Supplier Diversity Spend	11.7		11.7	14
Controllable O&M Costs ($M)	15		15.6	14.5
SCM Operating Cost as % of Total Managed Spend	0.7		0.74	0.86
Strategic Sourcing Savings - $	17.6		16	33.64
Working Capital Efficiency	1.5		N/A	1.5
Cost Avoidance	25.4		20	33.69
Dispute Management	60		N/A	20.5
% of Spend Benchmarked	92		N/A	87
Source: Response to Discovery, OC-428				

PSEG began the balanced scorecard process in 2008 for the Supply Chain Division. For the most part, the 2009 results met the targeted goal for the year. One metric that is noticeably under expectations is the measurement of customer satisfaction. The company measures this by sending out to its customers a 13 question survey and the scores for each question range from 1 to 7. As shown above, not only did SCM not meet the target for 2009, but SCM also decreased their score from last year. A couple of the questions that received the lowest scores in the survey related to how well SCM understood the

[61] Response to Discovery OC-428.

business requirements of their internal (PSEG) customers and how well SCM did in resolving supplier-related performance and quality concerns.[62]

PSE&G has continued to use their strategic sourcing initiatives mentioned above to obtain savings and avoid costs where it is possible. As seen in the table above, SCM exceeded 2009 targets for both strategic sourcing savings and cost avoidance by a significant amount.[63] Strategic sourcing savings is measured by taking the old price less the new negotiated price times the quantity purchased. If a service is being purchased, then the savings is calculated by taking the lowest qualified bid less the final selected bid. Cost avoidance is measured by negotiating away any unanticipated price increases, specifically those that were not in the budget.

For the 2010 balanced scorecard, PSE&G added three operational metrics: Plant in Service Dollars (CWIP), Achievement of Major Project Milestones, and Percent Below Index Shifts for Material Costs. The Achievement of Major Project Milestones metric is centered on the completion of the Susquehanna-Roseland Transmission project milestones according to the plan developed by PSEG and Burns and McDonnell. The Percent Below Index Shifts for Material Costs metrics is defined as: "Ensure any costs increases are less than changes in Market Indices (manage cost to 3% less than changes in market indices)."[64]

Performance Evaluation – In our interview, Bob Rankin, Director of Strategic Sourcing, mentioned that his performance is evaluated based on overall cost savings, supplier diversity targets, bid cycle effectiveness, and purchase order efficiency.[65] Overland requested performance evaluations of the managers and directors in the Supply Chain business unit. However, PSE&G chose not to make the evaluations available to us during the period of this audit.

Benchmarking and Key Performance Indicators – The Supply Chain division participates in one major benchmarking study with UPMG (Utility Purchasing Management Group). UPMG compiles data from 22 utilities in 121 different metrics for its 2009 study (using 2008 data). Below are a few of the metrics Overland found useful to analyze.

[62] Response to Discovery, OC-915.
[63] Response to Discovery, OC-428.
[64] Based on 4/20/10 Year to Date SCM Balanced Scorecard provided by Bob Rankin during the SCM interview, June 7, 2010.
[65] Based on an interview with Bob Rankin, Director of Strategic Sourcing, and Joe Jackson, Manager – Procurement Governance, June 7, 2010.

Table 28-27 – 2009 SPMG Benchmarking Study

Supply Chain Division 2009 UPMG Benchmarking Study				
Metric	**PSE&G**	**Highest**	**Median**	**Lowest**
Total Purchasing Employees / Total Company Employees	0.84%	2.80%	0.64%	0.11%
Inventory Turnover - T&D	4.1	4.1	1.62	0.35
Total Savings by Purchasing Org. ($ millions)	15.97	56.61	15.97	1.25
Total Cost Avoidance by Purchasing Org. ($ millions)	23.85	83.21	6.3	2.13
Total Purchased from all Diversity Suppliers ($ millions)	176.1	631.1	70	0.6
Source: Response to Discovery, OC-57, UPMG 2009 Supply Chain Metrics Benchmarking Study				

The metrics that Overland chose to represent in the table above are meant to be a summary of components that are important to an efficiently managed supply chain division. These metrics include results of staffing, inventory management, cost efficiencies, and regulatory compliance. Using this subset of key performance indicators, PSE&G's Supply Chain Division was placed at the median or in the upper half of the benchmark participants that took part in this study.