Legislative Budget and Finance Committee

A JOINT COMMITTEE OF THE PENNSYLVANIA GENERAL ASSEMBLY

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Assessing the Reliability of Pennsylvania's Electric Transmission and Distribution Systems

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Table of Contents

Table of Contents
(Continued)

Report Summary and Recommendations

The Legislative Budget and Finance Committee (LB&FC) authorized its staff to conduct a study of the effect of electric industry deregulation/restructuring on the reliability of the transmission and distribution systems. These are the systems that deliver electric power to consumers' homes and businesses.

In December 1996, Pennsylvania enacted legislation deregulating the retail market for electric generation supply and allowing companies to restructure. Pennsylvania's legislation also included several provisions to ensure that transmission and distribution service reliability is not allowed to degrade, and continued the Pennsylvania Public Utility Commission's (PUC) regulatory authority over transmission and distribution systems.

This report focuses on Pennsylvania's seven major investor-owned electric distribution companies (EDCs)--PECO, PPL, Allegheny Power/West Penn, GPU Energy (which recently merged with FirstEnergy), Duquesne, Penn Power, and UGI. They differ in customer size and mix, systems, and the areas they have been granted a franchise to serve. In recent years, some of the EDCs have undergone mergers and multiple and significant organizational changes. Some are part of a holding company utility subsidiary that includes multiple utilities and has consolidated certain operating functions for all of its utilities across state borders.

We found:

1. Reliability of transmission and distribution systems is a national concern. Experts recognize the potential for reliability problems to emerge as the electric industry is restructured and deregulated. Regulators, and others, therefore, engage in activities to determine if electric service reliability is negatively affected. For example, the U.S. Department of Energy formed a team of experts in August 1999 to review significant electric power outages and other disturbances that occurred during the summer of 1999. The team reported:

> The reliability events during the summer of 1999 . . . demonstrate that the necessary operating practices, regulatory policies, and technological tools for dealing with the changes are not yet in place to assure an acceptable level of reliability.

The team determined that some of the outages were directly related to problems with company distribution systems, including outages involving Commonwealth Edison[1] and GPU Energy's[2] outages in New Jersey. The study team's

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[1]Unicom is the parent of Commonwealth Edison Company. PECO Energy Company merged with Unicom Corporation on October 20, 2000, to form the Exelon Corporation.
[2]Pennsylvania's Metropolitan Edison (Met-Ed) and Pennsylvania Electric Company (Penelec) were combined with the Jersey Central Power & Light to form GPU Energy in 1996. In 1998, GPU Energy reorganized to form a process-based company with processes previously performed and managed on a local operating company basis managed centrally.

specific reliability findings for Commonwealth Edison illustrate several of the many factors that can result in diminished reliability of a company's distribution system.

- Transmission and distribution expenditures decline over time and become inadequate, with the decline coinciding with other company cost pressures.
- Planned distribution system upgrades are not implemented on schedule.
- Management of maintenance activities is weak, tracking of inspection and maintenance processes incomplete and poor, employee training and skill levels inappropriately matched to duties, and a backlog of desired corrective and preventative maintenance activities accumulates.
- Real-time information and historical records on distribution system condition are limited and not always preserved.
- Overall reliability performance is compromised by inadequate links between new business strategies such as reliability-centered maintenance, resources allocation, employee training and supervision, and reliability-relevant data collection and analysis tools.

Maryland and New Jersey carried out major investigations in response to 1999 power outages. New Jersey, for example, monitored GPU Energy for:

- workforce adequacy,
- adequacy of maintenance and inspection programs, and
- outage restoration performance improvement plans.

In May 2000, New Jersey ordered GPU not to proceed with any further workforce reductions "until the Board is satisfied that any further reductions will not adversely impact service reliability." In May 2001, New Jersey further ordered GPU not to implement any voluntary enhanced retirement program or any other layoff without first petitioning for approval. Such approval would be conditioned on a demonstration that any such diminution in the unionized workforce can be accomplished without impact on the development of skills and experience necessary to meet future workload requirements and reliability standards. When approving GPU's merger with FirstEnergy, New Jersey imposed this requirement on the company formed as a result of the merger.[3]

2. Several PUC bureaus monitor the reliability of Pennsylvania's electric service, but no single bureau is responsible for overseeing and assuring follow-up on all reliability matters. Several PUC bureaus are involved in monitoring Pennsylvania's electric distribution system. There is no single designated organizational unit responsible for ongoing and timely monitoring,

[3]GPU and FirstEnergy closed their merger on November 6, 2001.

assessment, and reporting to the Commission on all key distribution reliability matters. These bureaus carry out statutory and regulatory responsibilities and include:

The Bureau of Fixed Utilities (FUS) has staff assigned 24 hours a day, 365 days a year to respond to emergencies identified by the Pennsylvania Emergency Management Agency (PEMA) and follow up on matters brought to PEMA's attention by local emergency management agencies. FUS staff also review the reports companies are required to submit to the PUC during and after service interruptions when 2,500 or 5 percent of their total customers, whichever is less, have an unscheduled service interruption projected to last six or more consecutive hours. FUS staff reviews such reports and works closely with PEMA to assure that immediate problems are being resolved. FUS, however, is not responsible for follow-up on system reliability problems it identifies, such as a company's outage management system not correctly identifying service outage locations.

The Bureau of Consumer Services (BCS) assists consumers who have brought service reliability problems to the attention of companies and their problems have not been resolved. BCS will assess the complaint and, if appropriate, mediate with the company on behalf of the consumer. Such complaints typically involve localized problems with distribution lines that are not adequately maintained or are not adequate for their current load requirements. All consumer service reliability complaints, however, do not come to BCS.

BCS also monitors company consumer complaint trends, which are good indicators of possible problems requiring closer review and monitoring by the PUC. At times, as a result of such monitoring, the PUC and the company mutually identify problems and agree to a plan for improvement. When this occurs, BCS staff monitors company reports on the actions taken to implement the agreed-to plan, and further follows-up on activities directly related to consumer access and complaint handling. It has not been directed, however, to follow up on matters related to company transmission and distribution system reliability.

Currently, GPU and PECO, at the direction of the Commission, report quarterly to BCS on their activities to implement agreed-to improvement plans. Both companies submit quarterly reports with monthly reliability performance data as part of their agreements with the Commission.

The Bureau of Audits performs management and operation audits every five to eight years as required by statute. These audits typically include a review of the company's transmission and distribution systems' reliability and maintenance. Companies are to provide the PUC with written annual updates on their progress in implementing the PUC recommendations they have accepted.

The Bureau reviews company submissions but, is not responsible for ongoing follow-up with companies on their implementation of PUC recommendations. Two or three years after completion of the company's management audit, the bureau conducts a management efficiency investigation to assess the actual progress made in implementing certain prior audit recommendations.

Law Bureau. At times, the bureaus in conjunction with the Law Bureau conduct special investigations. The Bureau of Audits, for example, was involved with the Law Bureau in an informal investigation that resulted in the Commission in January 2002 approving a settlement agreement between the Law Bureau Prosecutory Staff and PECO Energy to resolve allegations regarding inadequate services in March 1999. The PUC Prosecutory Staff informed PECO in May 1999 that it might be in violation of the Public Utility Code and Commission regulations by cutting maintenance personnel to the extent they could not adequately respond to even minor power outages based on information available to the PUC. The settlement order describes a variety of activities that PECO implemented to improve its reliability. The order also required the company to make available 29 additional staff for certain types of service restoration above the totals projected by the company for 2001 and 2002.

The Bureau of Conservation, Economics and Energy Planning (CEEP). CEEP performs the one new activity that has occurred since restructuring. CEEP played the key role in drafting the PUC's electric service reliability regulations. In 1999, the Commission directed CEEP to monitor company reliability by submitting a report to the Commission on company reliability performance as outlined in company annual reliability reports.

The PUC also obtains input on service reliability issues through public input hearings usually conducted in conjunction with company requests for rate adjustments. With the establishment of caps on transmission and distribution rates as part of Pennsylvania's deregulation of the electric power industry, such hearings occur with less frequency. For most companies, the next public hearings associated with rate reviews will not occur until 2004 or later.

3. Performance monitoring standards and reporting requirements[4] **are inadequate to assure that reliability of the distribution system does not deteriorate.** We found:

- *The PUC's minimum performance standards*[5] *do not assure that reliability of distribution systems will not deteriorate because they are on average significantly below company historic performance levels.* On average, a company's reliability performance could deteriorate between 40 and 50 percent from its prior five-year average performance before the company would be out of compliance with the Commission's minimum performance requirements. Companies not meeting the PUC's minimum performance target must provide additional information to the PUC. In other states, however, companies are routinely required to report such information. In Massachusetts, moreover, companies whose performance is at the PUC's minimum performance standard incur the highest fiscal penalties that the state imposes for failing to meet performance standards. While several companies have internal standards that are more rigorous than those established by the PUC, at least one company reported to the PUC it had adopted the PUC's minimum performance standard as the company's reliability performance targets. In other words, the company can meet both its internal reliability goals and the PUC's minimum performance standards by providing service significantly less reliable than its service prior to deregulation and restructuring.

- *Companies are not required to report all unscheduled service interruptions.* The Commission's reliability regulations allow companies to exclude

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[4]PUC electric service reliability regulations require companies to file a report with the PUC on or before May 31st of each year on the reliability of the company's distribution system in the prior calendar year. The report must include a table showing for the most recent year and five preceding calendar years, the performance indices required by the PUC to assess the reliability of company systems. Currently, the Commission requires reporting of information on the average frequency of system interruptions (SAIFI), duration of system interruptions (SAIDI), interruption duration for those customers whose service was interrupted (CAIDI), and momentary service interruption frequency (MAIFI). The report must also include an assessment of electric service reliability for the company's distribution system and operating areas designated by the company; discussion of the company's programs and procedures for providing reliable electric service; and description of each major event for which service interruption data are not reported, including the time and duration of the event, the number of customers affected, the cause of the event, and any modified procedures adopted to avoid or minimize the impact of similar events in the future.

[5]The Commission in a December 1999 order established historic performance levels for each company based on the company's average performance on certain reliability indices during the five-year period from 1994 through 1998. It also established minimum performance levels for each company at two standard deviations from the company's historic performance level. Companies failing to meet their PUC minimum performance standard must submit additional information to the PUC, including analysis of the service interruption patterns and trends in the operating area(s) not meeting the PUC's minimum performance standards and the operational and maintenance history of the affected operating area(s), a description of the causes of the unacceptable performance and the corrective measures the electric distribution company is taking, and the target dates for completion.

service interruptions due to major events[6] the company identifies when reporting on their reliability performance. The PUC's service outage regulations that require reporting for significant outages, however, do not cover all unscheduled service interruptions that companies exclude. As a result, the Commission does not have information on all unplanned and sustained customer service interruptions.

- *Companies are not routinely required to report the causes of their unscheduled interruptions.* Without such information it is impossible to determine if company performance is within or outside of the control of the company, or assess if the company is taking reasonable steps to assure its reliability is not diminished.

- *The information the PUC receives is not timely.* The PUC receives annual reliability performance data from companies mid-year of the subsequent calendar year. Significant diminishing of reliability can occur over the 17-month period provided for by the PUC. The annual reliability reports are, therefore, of limited use for monitoring performance to assure that reliability is not diminished with deregulation/restructuring.

  New York requires monthly and year-to-date summary reports of service interruptions for each company system and operating area. The report must include the number of interruptions by cause and the total hours of customer service interruption. Several other states, including Massachusetts, Michigan, Maryland, Illinois, and Ohio also have more rigorous reporting requirements.

4. The PUC has not provided an "even playing field" for companies reporting on their reliability performance. In particular, we found:

- *Wide differences exist among the seven major companies in the variation between their company historic performance levels and their minimum performance standards.* Such variations result from the methods and data used by the PUC to develop historic performance levels and standards for each company. As a consequence, the minimum performance standards are more rigorous for companies with small variations in their historic performance levels (such as PPL) than for companies that have wide variations in their historic performance (such as UGI). Because of such

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[6]The PUC's regulations define major events as service interruptions resulting from conditions beyond the control of the electric distribution company which affect at least 10 percent of the customers in an operation area for a duration of five minutes or longer. They also include unscheduled interruptions of service resulting from emergency load control and energy conservation to maintain the adequacy and security of the electrical system. Scheduled outages and service interruption to customers served under interruptible rate tariffs are not considered major events. Such outages, however, are not defined as sustained customer interruptions; and therefore, are excluded from reported reliability performance data.

variation, the PUC's minimum performance standards alone are not effective measures for monitoring company reliability performance.

- *Some companies have made changes to their reliability data systems, but have not provided information to the PUC to assure their historic performance levels and minimum standards remain relevant for assessing their performance.* Once data are no longer gathered and collected in the same way, they can no longer be used for purposes of historic comparisons and trend analysis without certain information to account for data-gathering differences. Allegheny Power and GPU, in particular, have introduced new outage management systems, and have suggested that their performance levels and standards are no longer relevant. They, however, have not requested the Commission to consider if adjustments are required, and have not provided data and information needed by the Commission to consider, or make, such adjustments.

  California and Massachusetts have explicit requirements for companies when changes are made to their reliability data gathering methods. They require company reporting of the information necessary to determine the effect, if any, on reported reliability data when changes are made in the way companies gather and report data.

- *Three provisions in the PUC's regulations can result in significant differences in how companies report on their reliability performance.* To date, the Commission has not clarified its understanding of such regulatory provisions, or identified criteria that must be met before companies exclude service interruptions from their reported reliability performance. Such provisions include:

  - <u>Operating area designations</u>. PUC regulations permit companies to designate operating areas for purposes of reporting on reliability performance. Such designated areas then serve as the base for calculating the number of customers affected by a major event which, in turn, is used to determine if a company can then exclude customer service interruptions from its reported reliability performance. The regulations, however, do not establish criteria that must be met for such designations, such as number of customers served in the area or historically defined service territories. Typically, 25,000 or more customers would have to experience service interruptions in an operating area before PPL and Duquesne could exclude customer service interruptions from their reported performance. However, because it has designated small operating areas, fewer than 9,000 customers on average would have to experience service interruptions for GPU to exclude customer service interruption data from its reported performance.

- Other affected operating area exclusions. The PUC's proposed regulation did not permit companies to exclude service interruptions from their reported performance data unless 10 percent of the customers in an operating area were affected by a major event, such as a major storm. The Commission's final regulation, however, indicates: "when one operating area experiences a major event, the major event shall be deemed to extend to all other affected operating areas of that electric distribution company."[7] Companies vary in how they interpret this provision. One company has aggressively interpreted the provision to mean that the PUC permits it to exclude from its reported reliability performance data all unplanned service interruptions for its entire system even if only one small operating area is affected by the major event.

- Beginning and ending of major events. Companies also are responsible for determining when a major event begins and when it ends. There is no requirement that companies rely on official weather information to establish when a major event begins or that the times are consistent with other reports companies must file with the PUC. As a result, some companies may combine two separate storms into a single major event, even though they had restored power to all customers for the first storm before the start of the second.

LB&FC staff reviewed the 2000 reliability reports along with the service outage reports companies file contemporaneously with the PUC. Four companies (PPL, Allegheny Power, Duquesne, and Penn Power)[8] excluded performance data for one major event in 2000. One company (GPU), however, excluded service interruptions for nine major events in its 2000 reliability performance data. One major event the company excluded was reportedly due to a storm with rain and heavy winds in the Reading area. Official daily weather records for that day, however, show no precipitation occurred in the area.

All the companies that excluded a major event from their 2000 reported performance excluded service interruption data for a storm that occurred on December 12, 2000. There were, however, significant differences in how companies treated the same event. As we discovered in analyzing the reported data for this storm, differences in the way companies interpret PUC regulations and calculate their reported performance can significantly alter the picture of company performance PUC staff presents to the Commission. We found that one company reporting that two of its four operating areas had not met all of the PUC's minimum performance standards in 2000 would have been able to report that it met all PUC standards if it had

[7]The regulations do not define "affected operating areas."
[8]PECO and UGI had no major events resulting in exclusion of service interruptions from their reliability performance data in 2000.

calculated its performance in the aggressive manner used by a second company. The second company reported the storm started and ended at different times than were reported to the PUC on the company's service outage report and reported two storms as one major event.

The first company excludes from its reliability indices only customers in operating areas directly affected by a major event. The second company, however, excludes all service interruptions for its entire system when one of its operating areas experiences a major event. As a result, for 2000, the first company's reliability indices change only 3 to 11 percent when service outages associated with major events are added into its reliability performance data. The second company's reliability indices, however, change from 25 to 191 percent when outages associated with major events are added to its reliability performance data.

5. Limited review, follow-up, and reporting of reliability performance has occurred. The Bureau of Conservation, Economics and Energy Planning (CEEP) is responsible for receiving and reviewing the annual reliability reports companies submit. Based on the information provided to the LB&FC staff, CEEP has engaged in limited follow-up with companies following receipt of their submissions.

LB&FC staff reviewed the annual reliability reports submitted to the PUC by the seven largest companies. As noted above, we found inconsistency among companies in how they calculate their reliability performance. We also found:

- Companies provide general information about their reliability programs, but not information sufficient to determine if the reliability programs they describe are being implemented.

- Companies whose performance is below the PUC's established minimum performance standards do not provide in their reliability reports information sufficient to determine if the corrective actions they propose to address reliability problems are implemented and if the identified problem has been corrected, and if not, why not.

The absence of information sufficient to allow the PUC to determine if companies are implementing their reliability programs as described is significant since the

PUC is still in the process[9] of implementing the statutory requirement that it establish regulations regarding inspection, maintenance, repair, and replacement standards for electric distribution systems.

In 1999, companies took the position that their reliability performance reports were confidential and proprietary. The Commission, however, rejected this because transmission and distribution services are monopolistic and regulated; and therefore, companies are not competitors for these services. The Commission, moreover, stated:

> . . . an important policy goal that was to be met in restructuring the electric industry was the preservation of the integrity and reliability of electric service and the electric transmission and distribution system. In light of this goal, it would not be in the public interest to deny public access to this information.

The Commission, however, has not released a report on company reliability performance or published company reports on its website. The Commission has published reports on consumer satisfaction with company services. The 2000 survey, for example, indicated that 84 percent of those surveyed were satisfied with the company responses to "other" calls, which include contacts about trouble or power outages, billing matters, connect/disconnect requests, customer choice, and miscellaneous issues. The survey did not, however, address specific reliability concerns such as customer satisfaction with company restoration of service after a power outage and satisfaction about company answers to questions about when power will be restored.

6. Reliability appears to be diminishing in two companies. LB&FC staff reviewed and analyzed the multiple sources of data available to the PUC to

[9]The PUC in the preamble to its final electric service reliability regulations noted that its reliability regulations did not include inspection and maintenance standards. The Independent Regulatory Review Commission recommended the Commission reconsider the matter and evaluate what other states have done or are doing regarding inspection and maintenance standards. In the preamble to its final electric service reliability regulations, the Commission directed CEEP to study the issue of developing specific inspection and maintenance standards and to submit recommendations to the Commission for consideration. In December 2001, CEEP met with companies and initiated a study of inspection and maintenance practices and requested submission of information on such practices by mid-January 2002. The Bureau is currently in the process of conducting the study. LB&FC staff reviewed the reliability requirements of several relevant states. States typically do not have specific minimum performance standards for inspection and maintenance programs that companies must meet, but they do have ongoing and detailed reporting requirements concerning such programs. In this way, the states are able to assess whether companies have reasonable inspection and maintenance programs, if they are implementing their programs, and if not, why not. Such information is routinely reported and available for use by the state commission to assess the reasonableness of the programs and monitor company implementation and action to assure system reliability. California and Illinois, for example, also make such plans (along with company reliability reports) available to the public through their websites.

assess the status of reliability of Pennsylvania's major investor-owned distribution systems[10] in recent years. We concluded:

- Reliability for three of the seven major companies is similar to their historic performance levels. The three companies include one large company (PPL) whose reliability has remained relatively stable over the years. Such stability is reflected in the company reliability performance data and its winter and non-winter storm restoration efforts. A second company (Duquesne) had allowed its distribution system reliability to degrade in the early 1990s; but, after review by the PUC, it initiated significant plans to improve its reliability performance in the mid-1990s. The effects of the company's efforts are now reflected in its reliability performance data. The third company (UGI) is small. This may account for the historic variability in its reliability performance data. The company, however, has no negative audit findings, and has had little increase in its reliability complaints to the PUC.
- Reliability for one of the seven major companies appears to be improving after follow up by the PUC and aggressive actions by the company in recent years to reverse the trend of diminished reliability performance. The company (PECO) has also committed to implementing a quality of service plan that includes performance standards more rigorous than those of the PUC.
- Efforts to improve reliability to address diminished performance have been implemented by one company. Such improvements, however, are not yet reflected in the company's (Penn Power) performance data.[11]
- We have concluded there is cause for concern regarding the reliability of two of the seven companies. The companies, GPU and Allegheny Power, have encountered difficulty in their efforts over several years to implement new outage management systems, and they attribute the performance problems reflected in their reliability data to problems with the new systems. These companies, however, account for most of the service interruptions reported to the PUC through PEMA that involve equipment failure (and exclude accidents). They have not always complied with PUC

[10]These included annual reliability data reported to the PUC for 1999 and 2000, supplemental data submitted by companies on the causes of sustained interruptions, daily reports received by PEMA from local management agencies with information on the causes of outages, consumer reported reliability complaints, service outage data filed contemporaneously with the PUC, most recent PUC audits and company reports on the status of implementation of audit findings, and other publicly available information.
[11]There may be a time lag between when distribution system improvements are initiated and when their results are reflected in improved performance. Some improvements may take as little as 10 months to implement, but their effect might not be reflected in performance data until the following year. Other improvements may take years to accomplish, and their influence on reliability performance, therefore, is not immediately apparent. Similarly, the effect of allowing distribution systems to slowly diminish might not be reflected in reported performance data.

service outage reporting requirements concerning numbers of customers affected or numbers of workers assigned to repair work.

All of Pennsylvania's major companies are not able to report momentary service interruptions. The Commission, therefore, in April 1999, waived[12] this reporting requirement for those companies but requires that companies with such waivers report to the Commission any changes in their ability to collect momentary interruption data as part of their annual reliability reports. The Commission did not waive its reporting for PECO, PPL, Allegheny Power, GPU, and Penn Power. PECO, PPL, and Penn Power reported the required performance data in their 1999 and 2000 annual reports. Allegheny Power and GPU, however, have not fully complied with the Commission's reporting requirements for momentary interruption data. They have also not requested or received a waiver of such reporting requirements.

Allegheny Power and GPU also have negative audit findings concerning reliability and safety. All of the companies' negative audit findings have not been resolved.

FirstEnergy, which operates Penn Power, recently acquired GPU's Pennsylvania operating companies (Metropolitan Edison and Penelec). FirstEnergy officials have indicated a willingness to work closely with the PUC to provide accurate and complete reliability data to the PUC for GPU's operating companies and to assure compliance with the Commission's reliability reporting requirements.

The PUC staff appreciates the importance of prompt follow-up on reliability matters. As part of the PUC's responsibility to address reliability and to insure that current structures and requirements meet this obligation, an internal working group was established in 2002. The internal working group's ongoing assignment is to review and submit a comprehensive report including recommendations with respect to the PUC's reliability monitoring process for the Commission's consideration and decision.

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[12]The Commission in its order did not include all of the waivers required by companies to implement the electric service reliability regulations, or describe why such waivers are required or their duration. The order, for example, did not indicate that one small company was unable to exclude major event data from its reliability performance data. The PUC, therefore, established and published performance levels and minimum performance standards for the company that include major event data. By informal agreement with CEEP, the company correctly reports all reliability data to the Commission with all major events included in the performance indicator. Another large company is unable to provide actual customer counts and relies on percent of load to identify when it is affected by a major event. The company disclosed this to the Commission when it submitted data to establish its historic performance levels and minimum performance standards. One other major company because of the design of its systems operationally defines a sustained interruption differently than PUC regulations, and another operationally defines a major event differently. The latter company subsequently modified its systems to report major events consistent with Pennsylvania regulations. The other company has not yet been able to make such changes.

Recommendations

1. **The PUC should designate a lead unit responsible to assess, monitor, and conduct ongoing and continuous follow-up with companies on the reliability of their transmission and distribution systems.** Several units currently are involved in performing specific activities relevant to assuring the continued reliability and safety of distribution and transmission systems. However, a lead unit with primary responsibility for ongoing and continuous monitoring and follow-up responsibility has not been assigned. Currently, the Bureau of Consumer Services engages in on-going follow-up and monitoring of companies for certain customer service issues, but it has not been assigned to perform such monitoring and follow-up for distribution system reliability. Because of the number of years required to restore the reliability of systems that have been allowed to degrade or diminish over time, it is important to closely monitor multiple sources of information on company reliability performance and follow up promptly on all indicators or signs of potentially diminishing reliability. Without such ongoing follow-up, moreover, companies operating utilities across state boarders may focus their improvement efforts in states where aggressive follow-up has been initiated.

2. **The PUC should revise and enhance its reliability reporting requirements and performance monitoring standards.** To accomplish this recommendation, the PUC should:

    a. Review all reliability plans for conformity with regulatory requirements and reject plans that do not provide all the required data.

    b. Require submission of summary monthly and year-to-date information on the causes of all service interruptions. Such information is essential to interpret the information reported in the annual reliability reports and to follow up with companies on the performance they report. (Current regulations authorize the PUC to require submission of such information.)

    c. Request additional information from companies on their performance whenever it deviates from historic performance levels (e.g. 20 to 25 percent), not when performance has diminished by 40 to 50 percent from historic levels.

    d. Require such companies to identify the specific equipment that failed, the cause of the failure, and plans to address such failures.

    e. Require that companies advise the PUC of any problems with their reliability data gathering systems and immediately report to the PUC all changes to such systems that affect the PUC's historic performance levels.

f. Require companies to document all changes to their data gathering systems and provide detailed documentation on the extent to which such changes affect the performance levels established for the company.

3. **The PUC should clarify its existing reliability reporting requirements to assure there is a "level playing field" among companies.** Specifically, the PUC should:

   a. Clarify that when companies exclude data for major events for other affected operating areas, they may only exclude service interruption data for customers in other operating areas where the customers themselves have directly experienced the event.

   b. Enforce the regulatory requirement that companies report the time a major event begins and ends.

   c. Clarify that when companies exclude service interruption data for a major event, only service interruptions associated with the event itself may be excluded (i.e., not interruptions due to factors other than the major event).

   d. Establish criteria that must be met (such as minimum numbers of customers or the geographic units company management uses to monitor reliability) for company designation of an operating area for reliability performance reporting.

   e. Require completion of a PUC service outage report for all major events companies plan to exclude from their reliability performance data, regardless of whether the event meets the PUC's service outage regulation thresholds.

   f. Require companies excluding major events from their reported performance to provide additional justification whenever the company time for customer restoration substantially differs from that of other companies experiencing the same event.

4. **The PUC should issue an order setting forth all waivers granted to companies in their reporting to the PUC on their reliability performance.** All companies are not now able to report on their reliability in conformity with the Commission's regulations, and may need to formally seek a waiver from the Commission. If the Commission agrees to allow such companies to report differently, it should formally provide waivers to such companies, and the

companies should disclose the reasons they are not in full conformity with PUC reliability regulations in all documents they submit to the PUC.

5. **The PUC should annually prepare a report for the General Assembly and the public on the reliability performance of individual companies.** The report should provide information on performance trends using as many years of performance data as are available, the causes of customer hours of service of interruption, and information on all major events associated with data excluded from the company's reported reliability performance. The information reported for major events should be similar to that reported by companies on PUC service outage reports, and a company's current performance should be compared to past performance during such events.

6 **The PUC should complete its inspection and maintenance study, which is currently underway, and establish regulations regarding inspection, maintenance, repair, and replacement standards for electric distribution systems as required by statute.** We do not recommend that the PUC adopt detailed and specific standards because all systems are not the same. The programs the companies have in place must be tailored to the design and age of their systems. Companies with newer systems, for example, might not have to conduct inspections as frequently as companies with older systems, unless flaws are identified in the manufacturer's product. We do, however, recommend that the PUC consider approaches taken by states such as Illinois that do not have specific performance standards, but routinely require submission of detailed documentation on programs and their goals and assigned resources, evidence the programs are being implemented as planned, timely information on any changes to the proposed programs or budgets, and detailed analysis of the results of such program efforts. Such plans and analyses should be publicly available to all parties, possibly over the Internet.

7. **The PUC should work more closely and continuously with companies whose reliability may be diminishing to assure that they are taking aggressive steps to prevent degradation of their transmission and distribution systems, and it should closely monitor company implementation of improvement plans.** Failure of a company to successfully implement an agreed on improvement plan should result in the PUC initiating an informal investigation and, if necessary, the imposition of fines for failure to implement improvements agreed to in a timely manner.

I. Introduction

The Legislative Budget and Finance Committee (LB&FC) authorized its staff to conduct a study of the effect of electric industry restructuring/deregulation[1] on the reliability of the transmission and distribution systems. When the reliability of the transmission and distribution systems is allowed to degrade, service disturbances and interruptions occur more often; and customers may be without service for longer periods.

Problems with the transmission and distribution systems can also result in public safety issues such as forest fires and explosions and public exposure to "down wires." They may require local emergency officials to provide emergency housing when families must be evacuated from their homes, and arrange for specialized services for technology dependent disabled children and adults cared for at home. Delayed responses to service interruptions can also result in public highways remaining closed for longer periods than necessary and families and businesses experiencing financial losses.

In December 1996, Pennsylvania's Electricity Generation Customer Choice and Competition Act[2] "deregulated" the retail market for electric generation supply. Pennsylvania's legislation also included several provisions to ensure that electric service reliability does not degrade and provided for the Pennsylvania Public Utility Commission (PUC) to continue to regulate transmission and distribution services.

Study Objectives

1. To identify key policies and activities in place to ensure reliable and safe transmission and distribution of electricity prior to energy generation deregulation and the extent to which such policies and activities have been modified.
2. To assess the current reliability and safety of Pennsylvania's electric transmission and distribution systems.
3. To assess the adequacy of the Pennsylvania Public Utility Commission's current monitoring of utilities' transmission and distribution systems to ensure continued reliability and safe provision of services.

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[1]Restructuring in the electric utility industry has been occurring nationwide since at least the early 1990s when some utilities started to reorganize, change their operating practices, consolidate their operations, and enter into mergers in part to prepare for anticipated competition in the electric generation supply retail market. Such competition occurs when states enact legislation allowing electric customers to choose their electric generation supplier rather than having to purchase electricity from the utility that previously had been granted a franchise by the state public utility commission to supply and sell electricity at regulated rates. Customers, however, continue to have power brought to their homes by the transmission and distribution systems of the electric utility that has been granted a franchise to serve their area.
[2]Act 1996-138, 66 Pa.C.S.A. §§2801-2812.

4. To identify additional actions that may be necessary to ensure that Pennsylvania's transmission and distribution systems are not diminished.

Study Scope and Methodology

To identify key policies and activities in place to ensure reliable and safe transmission and distribution of electricity prior to energy generation deregulation and the extent to which they have been modified, we met with Pennsylvania PUC officials to become familiar with the Commission's processes to ensure reliable electric distribution service. We also met with the North American Electric Reliability Council's[3] Mid-Atlantic Area Council representatives who have a major role in assuring transmission system reliability in much of Pennsylvania.

To assess the current reliability and safety of Pennsylvania's transmission and distribution systems, we focused on the seven major investor-owed utilities operating in Pennsylvania. In 2001, they accounted for approximately 99 percent of electric sales in the state.[4] We reviewed and analyzed annual reliability reports and service outage reports companies are required to submit to the PUC. Such reports provide information on the frequency and duration of certain service interruptions that customers experience as a result of problems with the transmission and distribution systems.

We met and spoke with representatives of the major investor-owned companies and reviewed and analyzed additional information they provided. Such information, when provided, included preliminary reliability data for 2001, information on the causes of service interruption data, as well as other information from their reliability reporting systems.

We also reviewed and analyzed audits and special reports, including confidential reports, prepared by PUC staff, and daily incidence reports provided to the PUC by the Pennsylvania Emergency Management Agency. We met with the Pennsylvania Office of Consumer Advocate, linemen from several utilities, and representatives of the Pennsylvania Rural Electric Association.

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[3]The North American Electric Reliability Council (NERC) is responsible for setting and maintaining the principles, criteria, standards, and guides for planning and operating reliable bulk power electric systems (i.e. electric generating plants, transmission lines, and equipment). NERC was established in 1968 as a result of the Northeast Blackout, which effectively shut down the northeastern United States and much of Ontario, Canada, on November 9, 1965. Prior to the blackout, reliability of electric bulk power systems was maintained by less formal and less extensive cooperation among utilities. NERC has operated as a voluntary organization—one dependent on reciprocity, peer pressure, and mutual self-interest of all those involved. NERC's members consist of ten regional councils, including the Mid-Atlantic Area Council.

[4]PUC, *Electric Power Outlook for Pennsylvania 2000-2005*, July 2001, p ii. The reader should note that the PUC's report counts Metropolitan Edison Company and the Pennsylvania Electric Company as two separate companies. Throughout our report, these two companies which are part of GPU (General Public Utilities) Energy have been referred to as a single system, consistent with the way in which GPU Energy chose to report annual reliability data to the Pennsylvania PUC.

To assess the adequacy of the PUC's current monitoring of the reliability of company transmission and distribution systems, we reviewed various reports prepared by PUC staff for the PUC Commissioners as part of their monitoring of companies' performance and implementation of corrective action plans. We also reviewed recent electric service reliability regulations, and PUC orders and procedures to implement statutory directives that service reliability not be diminished as a result of deregulation. We met with PUC staff to become familiar with how such orders and procedures are currently being used by the PUC to monitor reliability performance.

To identify additional actions that may be necessary to ensure the adequacy of Pennsylvania's electric transmission and distribution systems, we reviewed similar activities underway in other states.

This study focuses primarily on reliability of the electric distribution systems. Most outages customers experience are caused by problems with company distribution systems. State governments, moreover, have greater control over distribution systems than transmission systems. Increasingly, federal and other self-regulatory organizations have primary roles in assuring the reliability of transmission systems.

Pennsylvania's electric deregulation legislation provides for temporary caps on the amount companies can charge for electricity, as well as temporary caps on transmission and distribution charges, in exchange for requiring customers to pay a "transition charge" to allow companies to recover their PUC-determined "stranded" costs[5] (i.e., investments made under the regulated system that might not be recovered with deregulation). Such caps were in place during the course of this study. The effect of deregulation on the cost of electricity service for consumers was, therefore, not within the scope of this study.

Assessing reliability performance relies in part on the use of indices developed by engineers for their use in evaluating equipment performance and planning and targeting resources to improve the reliability of a company's transmission and distribution systems. Such performance indices are expressed as numbers that can be confusing to a lay reader. For this reason, we have chosen to simplify the presentation of reliability performance indices by avoiding presentation of actual numbers, and relying on the use of terms, such as "better" or "worse," to characterize changes in the reported indices. Such terms, however, do not characterize a company's performance; rather they simply describe the direction of the performance indicator over time.

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[5]Defined by the act as, "an electric utility's known and measurable net electric generation-related costs, determined on a net present-value basis over the life of the asset or liability as part of its restructuring plan, which traditionally would be recoverable under a regulated environment but which may not be recoverable in a competitive electric generation market and which the commission determines will remain following mitigation by the electric utility."

We have throughout the report provided exhibits and tables summarizing information for each of the major investor-owned companies. The reader is cautioned not to utilize all such tables in an attempt to compare one company's performance against another. Companies serve different areas, have different operating systems, and different reliability data reporting systems. The available reliability performance data do not, therefore, lend themselves to comparing one utility against another. Rather, each company's performance should be considered in relation to its prior performance.

Acknowledgements

We express our appreciation to Pennsylvania Public Utility Chairman Glen Thomas and the staff of the Commission, in particular Veronica Smith, the Executive Director of the Commission. We appreciate the cooperation we received from the Pennsylvania Office of Consumer Advocate, PJM Interconnection, the Energy Association of Pennsylvania and its members, representatives of organized labor, and the Pennsylvania Rural Electric Association. We also thank company staff with whom we met and who provided additional information on their reliability systems and performance.

Important Note

This report was developed by Legislative Budget and Finance Committee staff. The release of this report should not be construed as indicating that the Committee's members endorse all the report's findings and recommendations.

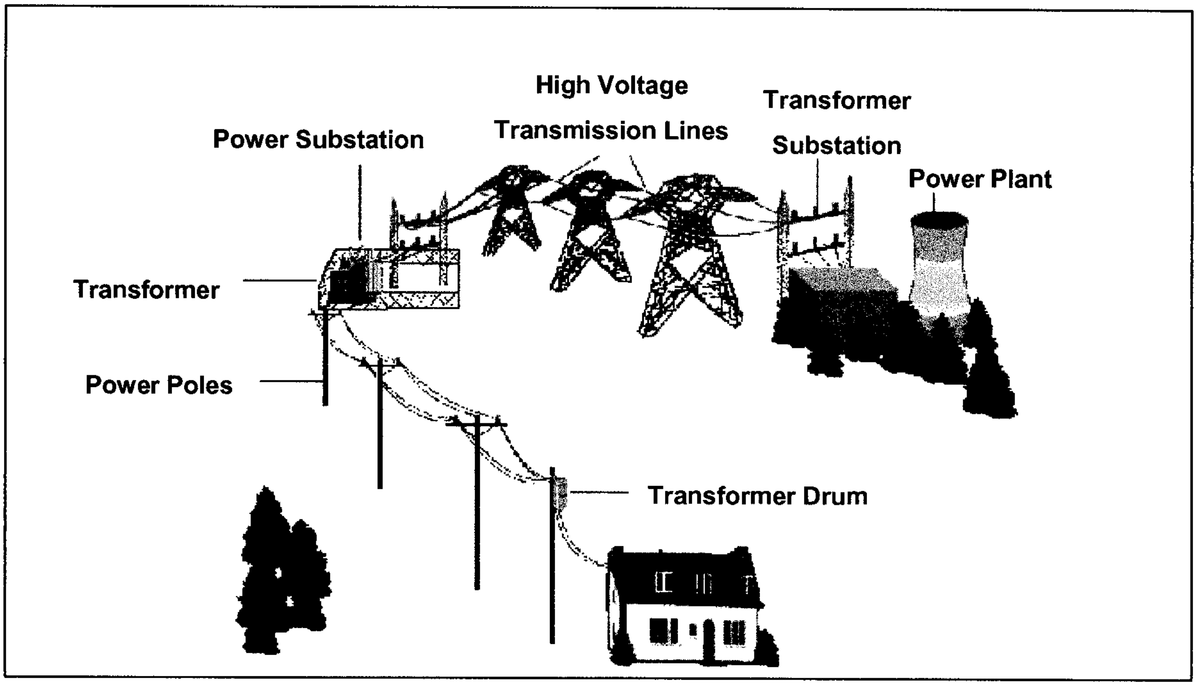
Any questions or comments regarding the contents of this report should be directed to Philip R. Durgin, Executive Director, Legislative Budget and Finance Committee, P.O. Box 8737, Harrisburg, Pennsylvania 17105-8737.

II. Pennsylvania's Electric Distribution Companies

In order for electricity to reach a customer's home, it must be generated, transmitted by high-voltage transmission lines, and then brought to the consumer's home, or business, through a utility's electric distribution system. Exhibit 1 shows how electric power reaches consumer homes.

Exhibit 1

Electric Power Generation, Transmission, and Distribution



Source: *How Power Distribution Grids Work* by Marshall Brain.

In the past, an electric utility supplied its customers with power that it generated, or purchased. The electricity was brought to its distribution system over transmission lines that it owned and operated in cooperation with other regional utilities. Typically, state public utility commissions have regulated the generation, transmission, and distribution of electricity in their states.

Since the late 1980s and early 1990s, many changes have been occurring in the electric utility industry. Many of these changes have been brought about in part by changes at the federal level. Appendix A provides a summary of some of the key changes at the federal level that have contributed to electric utility restructuring, reorganization, and deregulations.

One result of such changes is that many states have moved to "deregulate" electric retail generation and supply. This is accomplished by states allowing consumers to select their energy suppliers and take advantage of the benefits of competition among such suppliers, rather than requiring them to purchase electricity from the electric utility the public utility commission granted a franchise to provide service in their area. Charges customers pay for electric energy generation and supply are thus determined by market forces, rather than through state public utility regulation and rate setting processes. Deregulation further permits utility-affiliated generation and supply companies to compete to sell electricity outside of their franchise area, including competing for customers in other deregulated states.

Since the early 1990s, electric utilities nationwide, anticipating increased competition in power generation, have engaged in a wave of restructuring in an effort to remain competitive. Such restructuring takes many different forms. It can involve company reorganizations, mergers and acquisitions, staff reductions, changes in work practices, and greater reliance on new technology. Restructuring can also involve utility divestiture of power generation assets by selling them or transferring them to an unregulated subsidiary.

In December 1996, Pennsylvania enacted the Electricity Generation Customer Choice and Competition Act.[1] The act:

- required utilities to file restructuring plans with the Pennsylvania Public Utility Commission (PUC);
- capped utility rates as of January 1, 1997;
- prohibited anti-competitive behavior;
- authorized the PUC to determine a utility's stranded costs;
- authorized the PUC to approve a utility's competitive transition charge to be applied to the bill of every customer in the utility's service area regardless of the customer's electric generation supplier;
- required implementation of Pennsylvania's electric competition program by January 1, 1999; and
- continued PUC regulation of the reliability and safety of the transmission and distribution services.

The act also introduced a new term--"Electric Distribution Company" or "EDC" in place of the old term "utility." The term "Electric Distribution Company" refers to the PUC-regulated entity responsible for transmission and distribution of electricity to consumers in their franchise areas, regardless of the electric generation supplier selected by the customer. Such entities are also responsible for providing generation and supplying power for customers who do not select an alternative supplier. Appendix B provides more detailed information on key features of the act.

[1]Act 1996-138, 66 Pa.C.S.A. §§2801-2812.

Pennsylvania's Major EDCs

Pennsylvania has seven major EDCs[2] that are investor-owned. Many of these EDCs are subsidiaries that are parts of holding companies. Several have been involved in relatively recent mergers. As shown in Exhibit 2, several major Pennsylvania EDCs are held by holding companies based outside of Pennsylvania and operate across state borders.

Several companies that operate in more that one state have chosen to reorganize and consolidate certain functions. For example, Allegheny Power operates a single call center for all of its operating utilities out of Fairmont, West Virginia, where calls are handled directly or dispatched to several regional service centers. It also adopted a strategy to reduce inventory costs and increase efficiency of its storeroom operations by instituting "retail delivery"—a just-in-time delivery process where materials and supplies are packaged for individual jobs at either the material distribution facility in Connellsville, Pennsylvania, or Williamsport, Maryland. Some companies have centralized responsibility for reliability planning and performance data across all of their operating companies. Pennsylvania Power's reliability performance data, for example, are maintained in Ohio by FirstEnergy.

The federal Public Utility Holding Company Act of 1935[3] requires that a service company pay salaries and related expenses of employees who regularly work for more than one company system. For example, in 1994, Allegheny Energy, Inc., consolidated management of its three operating utilities (West Penn Power, Monongahela Power, and the Potomac Edison Company). Some "employees" of the Pennsylvania PUC regulated EDC providing transmission and distribution services, therefore, are not actually employees of the EDC; rather they are employed by Allegheny Energy Service Corporation, a service company subsidiary of the holding company. Pennsylvania statute requires the PUC to approve contracts between the entities it regulates and their affiliates.[4]

Some of these companies have undergone multiple and significant reorganizations in a relatively short period of time. Met-Ed and Penelec, along with the Jersey Central Power & Light, for example, became GPU Energy in 1996. In 1998, GPU Energy re-organized to form a process-based company with processes previously performed and managed on a local operating company basis managed centrally. Company operating regions also changed over the years. In 1998, GPU had five operating regions, with three in Pennsylvania. In 2001, GPU Energy was reorganized and reconfigured into four regions, with two in Pennsylvania. GPU is

[2]The count is eight if Metropolitan Edison Company (Met-Ed) and Pennsylvania Electric Company (Penelec) are counted as separate EDCs, and seven if they are counted as a single General Public Utility (GPU) EDC system operating in Pennsylvania. GPU reports its reliability data to the Pennsylvania PUC as a single system; therefore, we refer to seven rather than eight EDCs.
[3]Public Law 74-333.
[4]Public Utility Code, 66 Pa.C.S.A. §2102.

currently undergoing further reorganization as a result of its most recent merger with FirstEnergy.

The major EDCs in Pennsylvania differ in many ways. For example, as shown in Table 1 and Exhibit 3, they differ in volume of Pennsylvania energy sales and number and mix of customers. They also serve different geographic areas of the state, all of which are not contiguous.

Exhibit 2

Major Electric Distribution Companies (EDCs) in Pennsylvania and Their Holding Companies

EDCs/Companies	Holding Company
PECO Energy (PECO)	PECO Energy Company and Unicom Corporation (the Chicago-based parent company of Commonwealth Edison Company) merged on 10/20/00 to form the Exelon Corporation.
PPL Electric Utilities Corporation (PPL)	PPL Corporation, Headquartered in Allentown, PA. PPL Corporation includes PPL EnergyPlus, LLC; PPL Gas Utilities Corp; PPL Generation LLC; PPL Global, LLC; and PPL Services Corp.
Allegheny Power/West Penn Power (Allegheny Power)	Allegheny Energy, Inc., is headquartered in Maryland and is the parent company of four primary subsidiaries: Allegheny Energy Supply, Allegheny Ventures, Allegheny Energy Service, and Allegheny Power, the energy delivery business of Allegheny Energy, Inc. Allegheny Power operates utilities in Pennsylvania, Ohio, Maryland, West Virginia, and Virginia.
General Public Utilities Energy (GPU): Pennsylvania Electric Company (a.k.a. Penelec and more recently FirstEnergy—Western PA) and Metropolitan Edison (a.k.a. Met-Ed and more recently FirstEnergy-Eastern PA)	Pennsylvania Electric Company and Metropolitan Edison are two of three domestic electric utility subsidiaries (the other is Jersey Central Power and Light (JCP&L) in New Jersey) that conducted business under the name GPU Energy. GPU Energy was a subsidiary of GPU, Inc., a holding company headquartered in New Jersey. On 11/6/01, GPU Inc., merged with FirstEnergy Corp of Ohio.
Duquesne Light Company (Duquesne)	DQE Inc., is headquartered outside of Pittsburgh, Pennsylvania.
Pennsylvania Power (Penn Power)	FirstEnergy Corp., based in Ohio, holds all of the outstanding stock of its principal electric utility operating subsidiaries, Ohio Edison Company, the Cleveland Electric Illuminating Company, Pennsylvania Power Company, and the Toledo Edison Company. The Ohio Edison Company owns all of the outstanding stock of Pennsylvania Power Company. FirstEnergy was formed in 1997 with the merger of the Ohio Edison Company and Centerior Energy, the holding company for the Cleveland Electric Illuminating Company and the Toledo Edison Company. On 9/1/00, these companies transferred their transmission assets to FirstEnergy's subsidiary, American Transmission Systems, Inc. (ATSI), which owns and operates the Company's major high-voltage transmission facilities.
UGI-Electric Utilities, Inc. (UGI)	UGI Corporation is based in Valley Forge, PA.

Source: Developed by LB&FC staff.

Table 1

PA Major Electric Distribution Companies

Company	Number of PA Counties Served	2000 Total Energy Sales	Percent of Total Sales Commercial	Percent of Total Sales Industrial	Percent of Total Sales Residential
PECO	6	35.5 billion KWH	21.1%	44.4%	31.9%
PPL	29	34.7 billion KWH	33.1	29.6	34.4
Allegheny Power	20	19.3 billion KWH	22.1	43.3	31.1
GPU:	36				
Pennsylvania Electric Company (Also known as Penelec)		13.6 billion KWH	33.1	34.5	29.0
Metropolitan Edison Company (Also known as Met-Ed)		12.5 billion KWH	29.5	35.2	34.9
Duquesne	2	13.3 billion KWH	46.0	27	26.5
Penn Power	6	4.6 billion KWH	25.0	35.4	28.9
UGI	2	923.4 million KWH	35.4	12.7	51.4

Source: PUC, *Electric Power Outlook for Pennsylvania* 2000-2005, July 2001

Exhibit 3

Company's Service Territories and Total Customers

Company	Number of Customers	Service Territory
PECO	1,500,000	Delaware, Philadelphia, and parts of Bucks, Chester, Montgomery, and York Counties
PPL	1,300,000	Carbon, Columbia, Lackawanna, Montour, Northumberland, Schuylkill, Snyder, and parts of Berks, Bucks, Chester, Clinton, Cumberland, Dauphin, Juniata, Lancaster, Lebanon, Lehigh, Luzerne, Lycoming, Monroe, Montgomery, Northampton, Perry, Pike, Susquehanna, Union, Wayne, Wyoming, and York Counties
Allegheny Power	683,000	Armstrong, Cameron, Fayette, Greene, Washington, and parts of Adams, Allegheny, Bedford, Butler, Centre, Clarion, Clinton, Elk, Franklin, Fulton, Lycoming, McKean, Potter, Somerset, and Westmoreland Counties
GPU:		
Pennsylvania Electric Company (a.k.a. Penelec and more recently FirstEnergy Western PA)	580,000	Blair, Bradford, Cambria, Clearfield, Erie, Forest, Huntingdon, Indiana, Jefferson, Mifflin, Sullivan, Venango, Warren, and parts of Bedford, Clarion, Centre, Cumberland, Crawford, Elk, Franklin, Juniata, Lycoming, McKean, Perry, Potter, Somerset, Susquehanna, Tioga, Wayne, and Wyoming Counties.
Metropolitan Edison (a.k.a. Met-Ed and more recently FirstEnergy Eastern PA)	495,000	Parts of Adams, Berks, Bucks, Chester, Cumberland, Dauphin, Lancaster, Lebanon, Lehigh, Monroe, Montgomery, Northampton, Pike, and York Counties.
Duquesne	586,000	Parts of Allegheny and Beaver Counties
Penn Power	150,000	Lawrence, Mercer, and parts of Allegheny, Beaver, Butler, and Crawford Counties.
UGI	62,000	Parts of Luzerne and Wyoming Counties.

Source: Pennsylvania Public Utility Commission, *Electric Power Outlook for Pennsylvania 2000-2005*, July 2001.

III. Findings and Conclusions

A. *Restructuring and Deregulation in the Electric Power Industry Have Raised Attention Nationwide to Concerns About the Continued Reliability of Transmission and Distribution Systems.*

Experts nationally have recognized the potential for reliability problems to emerge as the electric industry is restructured and deregulated. Regulators and others, therefore, engage in activities to determine if electric service reliability is negatively affected.

U.S. Department of Energy's 1999 Power Outage Study Team

In August 1999, the U.S. Department of Energy (DOE) formed a Power Outage Study Team[1] to review significant electric power outages and other disturbances that occurred during the summer of 1999 and recommend appropriate federal actions to avoid them in the future. The DOE Power Outage Study Team reported:

> The reliability events during the summer of 1999 . . . demonstrate that the necessary operating practices, regulatory policies, and technological tools for dealing with the changes are not yet in place to assure an acceptable level of reliability.

The study team reports provide detailed information concerning the causes of several outages and disturbances. The team determined that some of the outages were directly related to problems with company distribution systems.

For example, in Illinois,[2] Commonwealth Edison's (ComEd) service territory experienced three major outages on July 30 through August 12, 1999. The Power Outage Study Team reported that while the transmission network was involved in the outages, "the three outages clearly resulted from problems with the distribution system."

Some of the team's specific reliability findings provide insight into several of the many factors that can lead to diminished reliability of a company's distribution system. As shown in Exhibit 4, reliability can diminish as a result of failure to invest in the system as planned, weak maintenance processes, lack of distribution system information required to successfully implement new business strategies

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[1]The team consisted of power system experts from DOE, its research laboratories, and academia. The team studied electrical power outages that occurred in six places: New York City, Long Island, New Jersey, the Delmarva (Delaware-Maryland-Virginia) Peninsula, the South-Central states, and Chicago. In addition, it studied significant electric power disturbances that occurred in New England and the mid-Atlantic area.

[2]Illinois enacted electric utility restructuring legislation in December 1997. The legislation provides for consumer rate cuts and rate reductions.

such as reliability-centered maintenance, and inadequate linkage between new business strategies.

Exhibit 4

U. S. Department of Energy's Power Outage Study Team's Assessment of the Causes of Commonwealth Edison's Distribution System Failures in Summer 1999

- Real-time information and historical records on distribution system conditions were limited and were not always preserved.
- Substation maintenance programs did not anticipate component weaknesses. Many fixed, periodic, substation maintenance programs had been scaled back or discontinued in transition to a "reliability-centered maintenance" philosophy. The collection of data measurements necessary for successful reliability-centered maintenance, however, was not fully in place. "In general, the ability to predict possible component failures from the inspections that were performed and the data that were collected was limited."
- Maintenance planning did not consider transformer overload analysis.
- Maintenance management contributed to the severity of the outages. "Management of maintenance activities was weak, tracking of inspection and maintenance processes was incomplete and poor; and employee training and skill levels were inappropriately matched to inspection duties . . ." A large backlog of desired corrective and preventive maintenance activities had accumulated in the years preceding the outages.
- Planned distribution system upgrades were not implemented on schedule.
- Transmission and distribution maintenance expenditures declined over time and became inadequate. The decline coincided with other cost pressures faced by ComEd, including those associated with industry restructuring and maintenance of its nuclear plants.
- Several business factors compromised reliability performance. Many "pieces" of reliability activities were in place, however "overall reliability performance was compromised by inadequate links between new business strategies (such as reliability-centered maintenance), resource allocation, employee training and supervision, and reliability-relevant data collection and analysis tools currently used in the field."
- The company's emergency preparedness and management plans did not address distribution problems. Under emergency conditions, information flows between the utility and organizations affected by outages were perceived as inadequate by these organizations.

Source: Developed by LB&FC staff based on the U. S. Department of Energy's Interim *Report of the U.S. Department of Energy's Power Outage Study Team, Findings From the Summer of 1999*, January 2000; and *Report of the U.S. Department of Energy's Power Outage Study Team, Findings and Recommendations to Enhance Reliability From the Summer of 1999*, March 2000.

The DOE report notes the outages caused ComEd and others to implement significant activities. These included the company's assessment of its systems and contracting to rebuild sections of its transmission and distribution system, along with investigations by others, including the city of Chicago.

The Power Outage Study Team also reported two utilities, including GPU Energy, were involved in distribution system outages in New Jersey[3] on July 5 through July 8, 1999. More than 100,000 GPU New Jersey customers were affected by the outages that were caused by the failure of two of four substation transformers that were damaged and could not be returned quickly to service.

According to the DOE report, the GPU Energy system has approximately 50 transformers like the ones that failed, and only two spare transformers. (Luckily, according to DOE, the spare transformers were stored at the substation in New Jersey where the transformers failed.) The report notes that such transformers are no longer manufactured in the United States and replacement or repair can take a year or longer. It also noted that GPU was increasing the number of spare transformers for its system from two to four.

State Investigations

Some states in recent years have conducted major investigations of outages. In New Jersey, for example, the Board of Public Utilities immediately initiated an investigation to determine the causes of the July 1999 outages and communication problems that occurred.[4]

The New Jersey Board of Public Utilities' initial investigation and discovery at first led to the issuance of a staff report[5] providing information on the causes of the July 1999 outages and the problems arising from poor communications with consumers and local authorities during the outages. The report also considered the extent of utilities' compliance with two prior storm reports issued in 1997 and 1998. The Board also engaged a management consultant to complete a technical review of the reasons for the outages and to recommend actions to increase reliability and reduce the risk of similar outages.

In May 2000, the Board adopted reports from its technical consultant for GPU Energy, Connectiv Power Delivery, Public Service Electric & Gas Company, and Rockland Electric Company. The Board required that each utility take certain actions to assure that it is prepared to generally improve reliability, handle stresses

[3]New Jersey enacted electric utility restructuring legislation in February 1999. The legislation provides for consumer rate reductions.
[4]The State of New Jersey Board of Public Utilities reported the information summarized here in a public order concerning its investigation issued on June 7, 2001.
[5]The Board made the staff report public on April 28, 2000.

on the system occasioned by peak demand periods, and improve restoration times when outages do occur.

Some of the Board's orders were considered "critical in nature and to require further monitoring and evaluation to insure the reliability of each utility's electric distribution system." The Board, therefore, retained a consultant to assist staff with such evaluations and to monitor company implementation of critical issues. Five of the 11 critical issues involved GPU Energy, which in 1998 had completed a reorganization that resulted in functions previously performed and managed on an operating company basis being performed centrally.[6] The Board's May 2000 order focused on:

- *Workforce adequacy.* The Board found that, in view of GPU's increased customer outage durations and its past maintenance and inspection history, a study should be conducted to justify the adequacy of the current level of GPU's workforce and should be submitted by September 15, 2000. In addition, the Board ordered that GPU not proceed with any further workforce reductions "until the Board is satisfied that any further reductions will not adversely impact service reliability."
- *Adequacy of maintenance and inspection programs.* The Board required GPU to physically inspect and review the adequacy of the company's testing patterns for approximately 37 "critical" transformers by June 1, 2000. The remaining "non-critical" transformers in the system were to be inspected and, if necessary, tested by the end of 2000. This recommendation arose out of concern with GPU's past maintenance and inspection history as set forth in the Board's report.
- *Outage restoration performance improvement plans.* The Board reported that GPU's average customer service restoration time in some areas was significantly worse than national averages and those for the state. The Board, therefore, ordered GPU to develop a targeted performance improvement program including analysis of required labor resources, information technology support, and maintenance practices.
- *Implementation of Supervisory Control and Data Acquisition (SCADA) systems.* The Board had questions about the implementation of this new system.
- *Lightning protection studies.* The Board identified a need for such studies.

In March 2001, the Board's consultant submitted its monitoring report. A summary of the consultant's findings concerning GPU's progress in addressing the critical issues identified by the Board can be found in Exhibit 5.

[6]Such functions included customer services, transmission and distribution, materials and services for its operating companies.

Exhibit 5

New Jersey Board of Public Utilities' Consultant's Assessment of GPU's Progress in Addressing Critical Issues

- GPU had implemented improved business processes in managing its workforce in that the planning, scheduling, and reporting processes for workforce management are what the consultant expected for an electric utility such as GPU.
- GPU, in the recent past, had not used contractors, as had other electric utilities, to give the company a greater resource pool to draw upon for storm restoration and fluctuating construction workloads. GPU had, however, increased the number of contract linemen and substation mechanics it employs from 0 to over 200 in just one year to accomplish an accelerated maintenance and capital improvement program in response to the Board's directives, in addition to expanding the availability of contractors for storm and emergency responses. As a result, GPU was generally meeting schedules and progressing on its capital improvement projects and during the consultant's review appeared to have sufficient workforce resources.
- GPU needed to develop the skills and experience of all GPU workers as a buffer against the negative impact of losing such valuable skills and experience because of significant retirements within a short time. The Board, therefore, ordered that GPU not implement any voluntary enhanced retirement program or any other layoff without first petitioning the Board for approval. Such approval would be conditioned on a demonstration that any such diminution in the unionized workforce can be accomplished without impact on the development of skills and experience necessary to meet future workload requirements and to meet the necessary standard of reliability set by the Board.[a]
- GPU completed installation of an Outage Management System to help the company to more rapidly discern the cause and scope of an outage, dispatch crews, and aid communications. Such factors help reduce service restoration time.
- GPU had developed a three-year reliability improvement work plan that would continue through 2002. To accomplish the plan, the company accelerated its construction-spending budget by approximately $56 million over a three-year period. The plan involved completing numerous projects involving substations, distribution circuits, underground networks, technology, and maintenance of equipment. The efforts further involve:
    - working to improve labor/management relations with an emphasis on communications;
    - developing alliances with external contractors;
    - restructuring the GPU Energy organization so that more decisions are made at the local level;
    - implementing 24 hours per day, 7 days a week troubleshooter coverage;
    - increasing the initial troubleshooter staffing levels by 25 percent; and
    - increasing the number of field supervisors.

[a]When approving the GPU merger with FirstEnergy, the Board continued this requirement.

Exhibit 5 (Continued)

- GPU's service territory in certain areas continued to experience inordinate service disruptions during and after storms. GPU at the request of the Board was sending technical representatives to such communities to explain the steps being taken to resolve the problems and submitted to the Board specific detailed work plans that the company intends to implement to improve reliability in these areas. The Board directed its staff to continue to monitor the company's response to such areas.
- GPU needed to perform a root cause analysis as recommended by the Board's consultant if its targeted customer service interruption duration times were not met in 2001. The Board ordered the company to provide the Board with such an analysis by April 1, 2002.
- GPU had not completed the testing of circuits ordered by the Board, but was proceeding as efficiently as possible. The Board, therefore, ordered GPU to proceed and submit detailed monthly progress reports on the transformer inspection program.
- GPU was taking reasonable steps to develop its functional specifications for SCADA implementation.
- GPU completed the Board-ordered lightning protection study and determined that 27 transmission substations required the installation of one or more lightning masts, which GPU planned to complete by the end of 2001.
- GPU, in view of its recent reorganization, needed to conduct periodic internal audits of its maintenance practices until such time as its internal auditors are satisfied that the maintenance programs have been fully implemented. The Board ordered that such internal audits be conducted and results provided to the Board in September 2001 and March 31, 2002.

Source: Developed by LB&FC staff from a State of New Jersey Board of Public Utilities public order concerning its investigation issued on June 7, 2001.

Another neighboring state, Maryland,[7] also initiated major investigations in late 1999 to determine the preparedness of its utilities to respond to major outages. The Public Service Commission of Maryland and a Task Force to Ensure Utility Service appointed by Maryland's Governor carried out the reviews. In July 2001, the Commission issued a series of orders in response to reports from task forces assigned to address specific issues. Some of the key provisions of the Commission's orders are found in Exhibit 6.

Other State Activities

The National Regulatory Research Institute (NRRI)—the official research arm of the National Association of Regulatory Utility Commissioners (NARUC)—has reported:

> Incumbents and entrants in newly opened markets for electricity, natural gas and telecommunication are subject to new pressures and conflicts on provision of reliable, high quality service to retail customers.

NRRI, therefore, surveyed states in 2000 to determine if they had formal standards on electric reliability, power quality, and service outages.

Forty states, including Pennsylvania, responded to the survey. Of those responding:

- 23 states, including Pennsylvania, have requirements for reporting and monitoring of reliability information;
- 13 states, including Pennsylvania, have electric service reliability performance standards;
- 7 states have penalties and rewards associated with meeting reliability performance standards; and
- 13 states have none of the above.

The majority of the states reported using the Institute of Electrical and Electronics Engineers, Inc. (IEEE) service indices to monitor reliability of electric service.

- 23 states use the System Average Interruption Index (SAIFI).
- 21 states use the System Average Interruption Duration Index (SAIDI).
- 15 states use Customer Average Interruption Duration Index (CAIDI).

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[7]Maryland enacted electric utility restructuring legislation in April 1999. The legislation provides for rate reductions for residential customers.

Exhibit 6

The Public Service Commission of Maryland's Actions in Response to 1999 Power Outages

The Public Service Commission of Maryland:

- Directed its staff to revise regulations to require more detailed reporting of major storm events while they are occurring to provide the Commission with the opportunity to exercise timely oversight of a utility's service restoration performance, and ordered the definition of a "major storm" be expanded to increase events that would trigger required reporting (to include rolling blackout situations) and that reports on such storms include information on:
    - requests for outside assistance as well as assistance actually received;
    - utility crews deployed;
    - causes of interruptions on and damage to the system;
    - restoration materials availability;
    - telephone line capacity and staffing during major storms; and
    - company self-assessment of its performance including lessons learned and plans for implementation of improvements in storm-related service restoration.
- Directed its staff to revise its regulations to expand oversight of utility operation and maintenance programs. The Commission determined that prescribing specific uniform requirements for the structure and content of utility operation and maintenance programs would not enhance reliability or mitigate the effects of outages caused by major storms since most utility-reported practices were similar. The Commission, however, recognized the important link between an effective operation and maintenance program and service reliability and the need for continuous monitoring of the structure and content of individual utility programs to ensure that they are efficacious. It, therefore, ordered that the revised regulations specify in greater detail the content of the inspection and maintenance plans that utilities were already required to submit. It determined that such plans should be submitted to the Commission on at least an annual basis (more frequently if revised) and specify:
    - frequency for performing procedures;
    - inspections to be performed; and
    - acceptance criteria for the inspection.
- Directed utilities to begin reporting reliability performance data starting with data for calendar year 2000. It also directed staff to revise regulations to reflect the Commission's order and to include in the proposed regulation modifications to Customer Rights Booklets so that customers are able to obtain information on the reliability of the distribution system that serves them.

Source: Developed by LB&FC staff from a series of orders issued by the Public Service Commission of Maryland in July 2001.

- 9 states use Momentary Average Interruption Frequency Index (MAIFI).
- 2 states use Customer Average Interruption Frequency Index (CAIFI).

Fourteen of the states responding reported they require utilities to follow national standards for steady state voltage. Eighteen states, including Pennsylvania, reported not having such requirements.

In addition, states report requiring regular, ongoing reporting of service outages. Such reporting includes:

- outage duration (21 states);
- outage causes (20 states);
- number of customers affected (19 states); and
- critical facilities or customers affected (10 states).

We reviewed the specific reliability reporting requirements of several major and surrounding states (California, Illinois, Maryland, Massachusetts, Michigan, New Jersey, New York, and Ohio). All the states we reviewed enacted legislation or have commission orders restructuring their electric power industries. All states with restructuring legislation, moreover, provided for rate reductions and/or rate freezes for residential consumers in their legislation.

No two states are exactly alike in their reliability reporting requirements. There are, however, several common themes that characterize their different approaches. Most of the states do not rely solely on the reporting of reliability indices to monitor reliability. Michigan, in fact, does not require reporting of reliability indices; relying instead on reporting of actual time for restoration during various service interruptions to help assure reliable electric service.

Most of the states we reviewed (California, Illinois, Maryland, Massachusetts, New Jersey, New York, and Ohio) monitor company systems for analyzing and addressing problems with poor performing circuits. Several of the states (California, Illinois, Massachusetts, Maryland, and Ohio) require detailed annual reports that include a variety of key information, such as planned and actual expenditures for transmission and distribution system investments and operation and maintenance procedures and practices. Most states require reporting of certain types of outages. New York, Illinois, and Massachusetts further require detailed reports on all service interruptions, both planned and unplanned. Ohio requires reporting for all transmission system outages. Appendix C provides relevant information on key states and their reliability and safety-related reporting requirements.

Provisions in Pennsylvania's Restructuring Legislation to Assure Service Reliability

When enacting legislation providing for restructuring of the electric utility industry, the Pennsylvania General Assembly declared the purpose of the legislation was:

> [T]o modify existing legislation and regulations and to establish standards and procedures in order to create direct access by retail customers to the competitive market for generation of electricity while maintaining the safety and reliability of the electric system for all parties. Reliable electric service is of the utmost importance to the health, safety and welfare of the citizens of the Commonwealth. Electric industry restructuring should ensure the reliability of the interconnected electric system by maintaining the efficiency of the transmission and distribution system.[8]

To ensure the reliability of electric service, the act required the following:

> Since continuing and ensuring the reliability of electric service depends on adequate generation and on conscientious inspection and maintenance of transmission and distribution systems, the independent system operator or its functional equivalent should set, and the commission shall set through regulations, inspection, maintenance, repair and replacement standards and enforce those standards.[9]

The act also authorizes, but does not require, the Commission to use performance-based rates as an alternative to existing rate base/rate of return ratemaking subject to the restrictions pertaining to rate caps in the act. To carry out the General Assembly's direction and to help assure that electric service in the Commonwealth continues to be as reliable and safe, the Pennsylvania Public Utility Commission engages in a variety of activities. These activities are described in detail in Findings B and C.

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[8] 66 Pa.C.S.A. §2802(12).
[9] 66 Pa.C.S.A. §2802(20).

B. *Pennsylvania's Public Utility Commission Performs Several Activities to Help Assure the Reliability and Safety of Electric Service*

The Pennsylvania Public Utility (PUC) Commissioners are responsible for establishing policy, including policies for reliable and safe electric transmission and distribution services in the Commonwealth. The Office of the Executive Director coordinates the activities of the PUC bureaus and is the management link between the Commission, the bureaus, and the office directors. The PUC's organization is shown in Exhibit 7.

PUC Activities to Assure Reliable and Safe Distribution Services

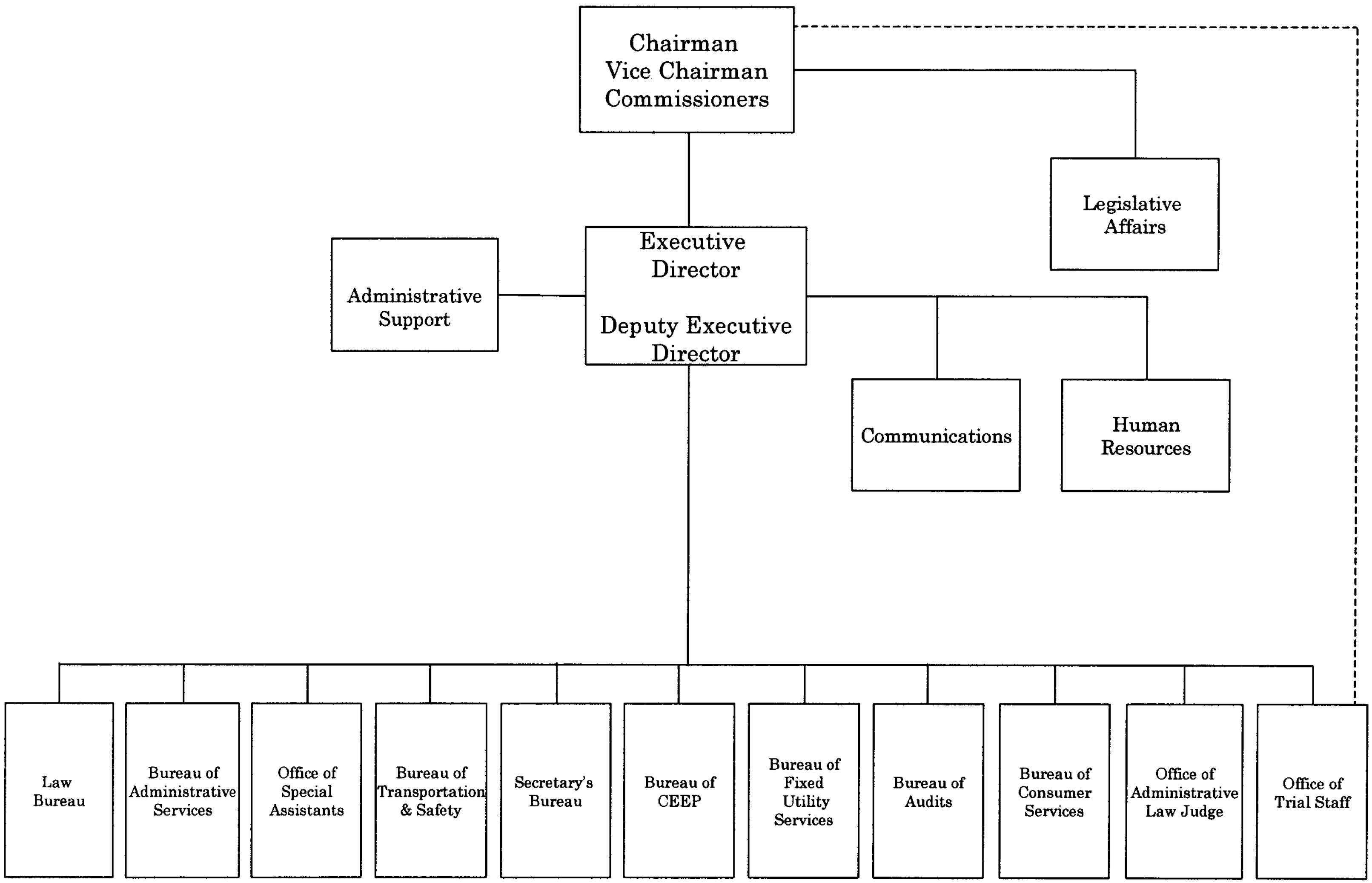
Currently, there is no single bureau responsible for overseeing and assuring follow-up on all reliability matters. No single unit has been designated responsible for ongoing and timely monitoring, assessment, and reporting to the Commission on key distribution reliability matters. Several bureaus, however, have important, but for the most part separate, roles in developing policy, monitoring, assessing, and reporting on the reliability and safety of the transmission and distribution systems of Pennsylvania's investor-owned companies. They include the bureaus of Audits; Conservation, Economics and Energy Planning (CEEP); Consumer Services (BCS); Fixed Utility Services (FUS); and Law.

The Law Bureau provides technical and legal support to various bureau staff members who are responsible for drafting regulations, guidelines, and policy statements. The various bureaus also carry out some of the following key activities to assure electric service reliability and safety. Some of these activities are performed on a continuing basis; others occur on a cyclical or intermittent basis. Others are as a result of a specific request, at times a request from the Commission.

- On a continuing basis, PUC staff:
  - respond to certain emergencies and power outages (FUS);
  - assess consumer electric service reliability complaints and, if necessary, mediate on behalf of such consumer (BCS); and
  - monitor consumer complaint trends for individual companies to identify potential quality of service issues (BCS).
- On a cyclical basis, PUC staff:
  - conduct management and operation audits that in part address transmission and distribution system reliability and other issues related to electric industry restructuring and deregulation (Audits);

Exhibit 7

PA Public Utility Commission
Organizational Chart



Source: Pennsylvania Public Utility Commission as of May 31, 2002.

- conduct management efficiency investigations to assess progress made in response to certain prior management and operations audit recommendations (Audits); and
- review annual reliability reports submitted by companies (CEEP).

➢ Based on specific requests, PUC staff:

- collaborate with companies to resolve mutually identified problems brought to the attention of the PUC by consumers and others;
- conduct special surveys and reviews;
- conduct informal investigations[1] with technical and legal support from the PUC Law Bureau; and
- conduct hearings to solicit public input on company performance.

All of the above activities that were performed prior to restructuring of the electric power industry in Pennsylvania continue to be performed, and are described below. The one new activity that has occurred since restructuring is the Bureau of Conservation, Economics and Energy Planning's[2] (CEEP) review of company annual reliability reports. The PUC's requirements for company reliability performance reports and review of such reports are discussed in Finding C.

Emergencies[3] and Outages

PUC staff members are involved during emergencies and certain power outages. The Director of the Bureau of Fixed Utility Services (FUS) represents the

[1]An informal investigation is authorized by regulation, 52 Pa. Code §§3.111-3.113, in response to an informal complaint. An informal complaint may be by letter or other writing and does not entitle the complainant to a formal hearing before the Commission. A formal complaint entitles the complainant to a formal hearing before the Commission unless the Commission determines a hearing is not necessary in the public interest, 52 Pa. Code §§5.21 et seq.

[2]This bureau is also involved in convening summer and winter reliability assessment meetings in the spring and fall; attending meetings of the North American Reliability Council, the East Central Area Council, and the Mid-Atlantic Area Council; monitoring and reporting on actions at the federal level concerning the federal role in relation to transmission systems; and monitoring wholesale and retail pricing. Since such activities relate to issues of generation reliability and pricing, they are outside of the scope of this study.

[3]As defined in the Emergency Management Services Code, 35 Pa.C.S.A. §7101 et seq., emergencies include man-made disasters, e.g., an industrial explosion; natural disasters, e.g., hurricane or snowstorm; and war-caused disasters, all of which threaten or cause substantial damage to property, human suffering, hardship, or loss of life.

PUC on the Pennsylvania Emergency Management Council[4] and has been designated authority to act for the Commission during emergencies.

FUS is the lead bureau responsible for managing and coordinating all actions of the PUC during emergencies. When a major storm is forecast, the FUS staff members currently contact each company to obtain information on the company's preparedness. They report this information to the Pennsylvania Emergency Management Agency (PEMA) and other PUC bureaus.

One FUS staff member serves as the Commission's Emergency Preparedness Liaison Officer working on a continuous basis with PEMA. Five FUS staff (with backup from three CEEP staff) are available 24 hours a day, 365 days a year, to address emergencies identified by PEMA.

PEMA contacts the PUC's Emergency Preparedness Liaison Officer, or his designee, to request assistance/intervention with a company whenever a problem identified by a county emergency coordinator cannot be resolved through direct contact with the local emergency manager and the company. PUC staff responds to all such requests from PEMA, and during emergencies are authorized, if necessary, to direct companies to take immediate, feasible corrective actions.[5] PUC staff report electric utilities typically are responsive to PUC and PEMA requests, as PEMA can mobilize significant state resources (i.e., PENNDOT) to provide companies with assistance during major service outages and emergencies.

Since early 2000, PEMA has provided the PUC's Emergency Preparedness Liaison Officer with a daily report of all incidents involving utilities reported to PEMA by local emergency management officials. Local emergency management officials typically alert PEMA of incidents of power outages or major problems because they may subsequently require state assistance. PUC's staff members routinely review the daily report to determine if their immediate follow up/intervention is needed to promptly resolve the reported problem.

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[4]Emergency management is a legal responsibility and function of local, county, state, and federal government. The Pennsylvania Emergency Management Council (PEMC) is responsible for overall policy and direction of statewide disaster programs and response capabilities. The Council is chaired by the Lieutenant Governor and has a membership that includes state agencies and county and local governments. The Pennsylvania Emergency Management Agency (PEMA) is the state agency that serves as the agent of the Council in implementing the state's disaster programs and planning. PEMA operates the Commonwealth's Emergency Operations Center from which the Governor and Lieutenant Governor oversee the state's response to developing emergency conditions. PEMA maintains communications with the 67 county emergency management agencies, monitors local conditions and provides state government support as appropriate.

[5]During emergency situations, feasible alternatives may not be available. For example, the PUC staff can direct a utility to secure outside assistance to restore power following a major storm if power restoration is progressing too slowly. Such direction, however, would not be feasible if the utility had not prepared adequately for the storm and had not in advance arranged for mutual assistance from utilities outside the storm's path. By the time extensive storm damage had occurred, the closest unaffected utilities would likely be assisting other utilities that had planned and prepared in advance for the major storm restoration.

LB&FC staff reviewed the PUC's log of electric utility daily incidents reported to PEMA from early 2000 through mid-year 2001. The incidents of power outages included in the log involve, for example, power outages where local emergency officials have been required to temporarily close roads, establish temporary shelters, and provide emergency generators for persons with critical care needs. They include incidents of explosions and fires involving utility equipment where local police and fire assistance was required, and where part of a community needed to be evacuated.

Pennsylvania's PUC requires electric utilities to report on some, but not all, power outages that occur. It requires all utilities to immediately notify the PUC when 2,500 or 5.0 percent of their total customers, whichever is less, have an unscheduled service interruption in a single incident for six or more projected consecutive hours.[6] Utilities must notify the PUC within one hour after preliminary assessment that such an unscheduled service interruption may be occurring. Written reports of such interruptions must be submitted within five working days after total restoration of service. Such reports are submitted to FUS and must include the following information:

- Approximate number of customers involved in a single incident.
- Geographical area affected in terms of the county and local political subdivision.
- Reason(s) for the interruption.
- Projected time for service restoration.
- Number of utility workers and others assigned specifically to the repair work.
- Date and time the utility first received information of a service interruption.
- Date and time that repair crews were assembled.
- Date and time that the supervisor made the first call.
- Approximate time that repair work was started.
- Actual time that service was restored to the last affected customers.

FUS staff[7] review the service outage information and reports submitted by the companies to the PUC. Their primary purpose in receiving and reviewing information on service outages, and other information reported by PEMA, is to assure that immediate problems are being resolved.

The PUC has not, however, designated a single unit within its organization to oversee and assure follow-up on company reliability performance on an ongoing basis with companies where indicated. FUS, therefore, does not routinely provide

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[6]52 Pa. Code §67.1(b).

[7]FUS staff also review accident reports filed by utilities and investigate when necessary. FUS staff report immediately to the Commission all reports of fatalities and occurrences of an unusual nature.

the service outage reports it receives on a contemporaneous basis, or the PEMA incident reports, to a unit that reviews such information to identify potential electric distribution reliability problems and determine if follow-up with a company is indicated.

The PUC does not routinely require electric utilities to file emergency response plans and does not require that such plans be tested at specific intervals. In 1999, however, FUS staff in conjunction with PEMA reviewed utility plans and automated systems in preparation for Y2K. As part of the reviews, the PUC for the first time became aware of significant problems one major company was having with its automated outage management system. The company's system was not correctly identifying the location and cause of outages. Such problems with the new technology slowed down service restoration times since utility linemen subsequently had to be called out to identify the source of such outages before restoration could begin.

Consumer Complaint Mediation

The Bureau of Consumer Services (BCS) plays an important role in assuring companies provide quality service for residential customers, part of which is reliable service. When a residential customer brings to BCS's attention a service reliability problem the company has not resolved, BCS will assess and, if appropriate mediate, with the company on behalf of the consumer. The one type of quality of service problem the Bureau does not mediate involves damages incurred as a result of power failures or company actions.

In August 2001, in conjunction with the Commission's increased attention to quality of service issues, BCS established uniform standards for the type of information companies must submit to BCS for review of a consumer complaint involving frequency and/or duration of service outages. Companies must provide:

- A two-year history of all outages for the customer's service address, including in chronological order the date, duration, and cause of each outage.
- Documentation of the company's action(s) to reduce the number and/or duration of the customer's outages.
- Detailed information on the reason for outage duration and the steps taken by the company to restore service as soon as possible for complaints involving outage duration.
- Any planned upgrade/system work that may reduce the customer's number and duration of outages, along with the estimated beginning and end dates for the upgrade/system work.

The complaints that come to BCS for mediation typically involve localized problems with distribution lines that are not adequately maintained or are not adequate for their current load requirements. Bureau staff members indicate that companies are usually responsive to their mediation efforts.

All consumer service reliability complaints, however, do not come to BCS. Typically, problems encountered by hospitals and nursing homes come to the attention of the PUC through PEMA, and members of the General Assembly often bring widespread service outage problems directly to the attention of the Commissioners for PUC staff review.

Monitoring Company Consumer Complaint Trends

Since all consumer reliability and quality of service complaints do not come to BCS's attention, the number of complaints it receives is not a measure of the extent to which consumers are affected by service reliability problems. BCS, moreover, does not rely exclusively on its complaints data to document the existence of company service reliability problems. The BCS complaint trends, however, are good indicators of possible problems requiring closer review and monitoring by the PUC.

For example, a storm front at the end of May and the beginning of June 1998 resulted in 331,600 PECO customers experiencing sustained service outages, including 13,500 customers in Chester and 11,000 in Delaware counties who were without power four days after the storm. In late June and early July of that same year, another storm affected 186,700 customers in the Philadelphia suburban counties, with some customers again without power for approximately four days. In May 1998, BCS received fewer than 20 total complaints about the company; the number increased to approximately 35 in June, and surpassed 50 in July. Given the large numbers of customers affected, the PUC complaint numbers are not reflective of the actual number of customers experiencing extended service outage problems. The 150 percent increase in complaints over the three-month period, however, was a clear indicator of a possible reliability problem that required closer PUC attention.

Similarly in mid-March 1999, a snowstorm hit the company's service territory, leaving 161,535 customers without electric service primarily in Chester, Delaware, and Montgomery Counties. Some were without service for approximately three days. In February 1999, BCS received about 25 complaints about the utility, and the number increased to almost 50 complaints in April. The BCS complaint numbers are not reflective of the actual number of customers experiencing serious service outage problems. The approximately 100 percent increase in monthly complaint volume, coupled with complaints from three counties' public safety officials, and local newspaper's editorials, however, were clear indicators of reliability problems that required PUC attention.

BCS, therefore, routinely monitors the trend in current and prior year monthly complaint volume it receives for individual companies, along with other information, to identify potential quality of service problems consumers are encountering. Currently, BCS must rely on the aggregate numbers of complaints received for purposes of ongoing monthly monitoring. Its database includes information on the specific types of quality of service problems consumers are encountering; however, such information is not immediately available for its analysis. (LB&FC analysis of this data can be found in Finding D.)

The BCS meets with company representatives concerning consumer issues that it identifies. When BCS' complaint monitoring identifies relatively significant increases in consumer complaints against a particular company, it brings this to the attention of the Office of the Executive Director for further review and analysis.

Collaboration to Resolve Mutually Identified Problems

As a result of such processes, the PUC and the company can mutually identify problems and agree to a corrective action plan. When this occurs, BCS staff members are involved in ongoing monitoring of reports from the company on the actions it has taken to implement the agreed-on plan of correction.

Currently, GPU and PECO are involved in such processes with the PUC at the direction of the Commission. The collaborative process with GPU illustrates how it occurs and how it can evolve.

Consumer complaints to BCS for the company more than doubled beginning in April 1999, and BCS continued to receive an elevated number of complaints for the remainder of the year. The BCS director and the Deputy Executive Director of the PUC met with company officials in November 1999 to discuss quality of service problems, especially customer access to the company during service outages and distribution reliability.

Following the meeting, BCS worked collaboratively with the company to establish performance measures and milestones to monitor utility plans to improve its performance. In the meantime, a member of the General Assembly and company employees brought problems with the company's emergency response and distribution systems directly to the attention of the PUC Chairman.

The company advised the Commission that improvements would be realized by June 2000, and agreed to provide the PUC with quarterly reports to allow the Commission to monitor performance improvements through June 2000. The company agreed that its reports would include call center statistics; information on justified service outage and service quality complaints that it receives and resolves; customer satisfaction survey data; company efforts to educate consumers regarding outage reporting; vegetation control activities and expenditures; progress reports on the status of the company's automated outage management system implementation and the hiring of new field staff; and monthly reliability performance data.

The company submitted its first quarterly report to the Commission in February 2000. Based on the reports submitted in June 2000, BCS recognized the company had not been able to realize the agreed-to performance improvement goals. BCS requested, and the company agreed, to continue to submit quarterly reports on its performance.

In June 2000, the PUC Deputy Executive Director formed an internal PUC working group to ensure there was no duplication of effort within the PUC, as several PUC bureaus had identified problems involving the company. The other purpose of the working group was to address service issues with the company before they became more serious and before there was need for formal action by the Commission.

In November 2000, BCS advised the company it was not meeting the improvement goals it had established for improved consumer access to the company's call center. BCS specifically requested the company to provide additional information about the reasons for the declining call center performance, the company's handling of outages and other service quality complaints, and the steps the company was taking to correct the problems. BCS noted that it was deferring to other PUC bureaus in terms of follow-up on other problems addressed in the company's performance improvement plan.

Within one month, the company responded to BCS and met with its staff. It acknowledged its customer service problems and indicated it was addressing them.

The company also acknowledged its reliability problems. It indicated it was examining the causes behind the declining performance, and planned to present the CEEP bureau with a plan to improve the company's performance.

In response to a recommendation from the PUC's June 2000 internal work group, the Commission agreed that staff should continue to monitor the company's performance and the company should continue to submit quarterly reports on activities taken to implement its performance improvement plan for two years. The company has fully cooperated with the PUC in submitting the required reports.

LB&FC staff reviewed the quarterly reports submitted by the company. The documentation indicates that BCS has followed up with the company on matters concerning consumer access and reporting, and the company made improvements in these areas. We were, however, unable to determine if other PUC bureaus are involved in relevant follow-up in other areas (e.g., reliability) where the company had agreed to performance improvements.

Management and Operation Audits and Efficiency Investigations

The Bureau of Audits performs periodic management and operation audits of the major Pennsylvania fixed utilities, including electric companies. It also completes management and efficiency investigations.

Management and operations audits are conducted every five to eight years as required by statute.[8] Such audits typically include a review of the company's transmission and distribution system reliability and maintenance. The scope of the review is determined through consultation with other PUC bureaus. Generally transmission and distribution maintenance budgets, plans, procedures, and performance reports, as well as the organizational structures in place to carry out maintenance operations are reviewed during such audits.

Final audit reports contain recommendations for improvements, if necessary, and are issued to the companies that develop implementation plans in response to the recommendations they accept. The Commission then releases the final audit report and the company's implementation plans to the public. The act requires the audits to be provided to the Office of Trial Staff and the Office of Consumer Advocate.

Management efficiency investigations are usually conducted within two or three years after the completion of the company's management audit. The purpose of such investigations is to assess the progress companies are making in implementing certain prior audit recommendations.

Management efficiency investigation reports contain follow-up recommendations for improvement, if necessary, and are issued to the company to develop an implementation response. The PUC's management efficiency investigations are available to the public.

Exhibit 8 provides information on the types of audits that have been performed for each of the major investor-owned electric companies and the status of current or future management and operation audits and management efficiency investigations.

[8]The Public Utility Code, 66 Pa.C.S.A. §516(a), requires these audits of any electric, gas, telephone, or water utility whose plant in service is valued at not less than $10 million.

Exhibit 8

PUC Management and Operation Audits and Management Efficiency Investigations Completed or Underway

Company	Date of Most Recent Management and Operation Audit Report	Date of Most Recent Management Efficiency Investigation Report	Status of Current or Future Management and Operation Audit	Status of Current or Future Management Efficiency Investigation
PECO	August 1999	N/A	N/A	Scheduled for summer 2002
PPL	June 1994	N/A	Report draft under review as of 2/02	N/A
Allegheny Power	May 2000	May 1995	N/A	N/A
GPU	December 1998	N/A	N/A	Fieldwork underway as of 2/02
Duquesne	March 1998	Late 1995	N/A	Report draft under development as of 2/02
Penn Power	May 1998	February 1994	N/A	Report draft under review as of 2/02
UGI	February 1997	N/A	N/A	N/A

Source: Developed by LB&FC staff from information provided by the PUC.

All the management and operation audits and the management and efficiency investigations include findings concerning electric service reliability. Several relevant PUC findings and company responses to PUC recommendations are discussed in Finding D.

Special Studies and Informal Investigations

The Bureau of Audits and other bureaus at times conduct special studies and informal investigations. Such studies and investigative reports, however, are typically not available to the public.

For example, in April 1998, the Bureau of Audits conducted a survey of companies' transmission and distribution maintenance/emergency preparedness plans and practices. The Commission directed the Bureau to undertake the survey as a result of several storms in northeastern United States during the winter of 1997-98. The survey provided the Commission and its staff with information on changes that had occurred in company practices. The survey information also provided Commission staff with baseline information when considering subsequent service outage issues brought to its attention by state legislators and others.

The Bureau of Audits and other bureaus can also be involved with the Law Bureau in informal investigations. In January 2002, for example, the Commission approved a settlement agreement between the Commission's Law Bureau Prosecutory Staff and PECO Energy Services to resolve allegations regarding inadequate services in March 1999 that were the subject of an informal investigation.

According to the Commission's Order approving the settlement agreement, the PUC Prosecutory Staff informed PECO in May 1999 that, based on information available to the PUC, it may be in violation of the Public Utility Code and Commission regulations by cutting maintenance personnel to the extent they could not adequately respond to even minor power outages.[9] With the assistance of the Bureau of Audits, the Prosecutory Staff requested PECO to provide a significant number of documents and information. PECO cooperated with the Commission providing the documents in August 1999.

Commission staff reviewed the documents and the applicable policies and procedures pertaining to the company's response to the power outages in March 1999, and the Bureau of Audits drafted a report on the company's responses to the 1999 outages. PECO was provided with a draft copy of the report for review in September 2000.

In December 2000, Prosecutory Staff released the final report to the company, which contained the Bureau of Audit's observations and recommendations with respect to the company's performance during the power outages. The report addressed storm response, manpower, vegetation management, and communications, highlights inadequacies present during the March 14, 1999, outage and corrective changes made by the company and changes deemed necessary.

On March 14, 2001, PECO provided the Commission with comments and an implementation plan, which noted that the majority of the recommendations contained in the Bureau of Audit's report had been completed. Based on comments by the Bureau of Audits, the Prosecutory Staff requested more detailed information about PECO's implementation plan. PECO provided the additional information in April 2001.

PECO had cooperated with the Commission during its informal investigation, and PECO publicly announced several major changes in its approach to service reliability and outage management that had been underway since 1998/1999. PUC Prosecutory Staff, therefore, explored the possibility of resolving the investigation through a Settlement Agreement in view of steps the company was taking to improve its reliability. Exhibit 9 summarizes some of PECO's initiatives.

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[9]Specifically, 52 Pa. Code §57.194(d) requires an electric company to restore service within the "shortest reasonable time."

Exhibit 9

PECO Reliability Initiatives

- *Vegetation Management*. It modified its program to include targeted tree trimming for identified problem circuits and expanded its vegetation management program to include removal of large trees deemed likely to fall on distribution lines.
- *Call Center Phone System*. It upgraded its call system from one that could handle 5,000 calls per hour to one that handles 30,000 calls per hour. It also instituted procedures that increase center staffing levels and direct more calls to call center agents (rather than an automated voice response system) in situations where it determines that the majority of outages will not be addressed quickly.
- *Emergency Preparedness*. It instituted emergency preparedness drills.
- *911 Center Support*. It designated specific employees to on-call rotations to provide support to 911 centers in Delaware, Chester, and Montgomery Counties.
- *Contractor Agreements*. It revised and strengthened its contract terms to include specific requirements for contractor crews, equipment, and response timeframes during emergency situations.
- *Resource Tracking*. It established procedures for tracking the actual, rather than potential, number of manpower available to respond during storm emergencies at regional levels and at the company's Emergency Response Center.
- *Secondary/Primary Restoration Focus*. During the later half of the 1990s, PECO introduced a new service restoration strategy. The new strategy relied on the use of qualified linemen trained to work on primary circuits (4000 volts and above) and others (such as trained substation mechanics, meter technicians, etc.) to work on secondary service (120/240 volts and below) restoration, rather than using primary qualified linemen to handle all restoration of service to customers. To successfully implement its new strategy for restoring service, PECO needed to have sufficient numbers of Energy Technicians trained and qualified in secondary restoration before being hit by major storms. The January 2002 order indicates that PECO had completed training for the Energy Technicians necessary to allow their participation in secondary service restoration.
- *Outage Management System (OMS)*. The company introduced new technology including a new outage management system to more efficiently respond to outages. In addition, it created a new position in the Dispatch Operations Center to assist Center personnel with the technical analysis of OMS data to assure that company staff members were properly using the system.
- *Statistical Analysis and Post-Event Assessment*. PECO strengthened its reliability assessment and emergency planning by performing statistical analyses of reliability indices after each major storm event to identify reliability issues to be addressed and by performing self-assessments after all major events to identify corrective actions that may be required and the steps required for their implementation.
- *Emergency Response Procedures*. To more effectively dispatch crews to service restoration during major storms, and thus reduce customer service restoration times, it transferred dispatch authority from the Operations Center to its local regions.
- *Outages Greater Than 24 Hours*. As part of the PUC settlement agreement with PECO, the company also agreed to target for restoration, problem circuits with outages greater than 24 hours.

Source: Developed by LB&FC staff from the PUC's January 2002 settlement agreement order.

In addition to the steps PECO had initiated, the PUC, in its settlement agreement with PECO, also required the company to make available 29 additional secondary restoration personnel above its projected totals for 2001 and 2002. PECO has also taken other steps not covered in the settlement agreement to improve its distribution system reliability. Some of these activities are discussed in Finding D.

Soliciting Public Input on Reliability Performance

The PUC staff are also involved at times in obtaining public input about utility services. The BCS, for example, requires companies to survey customers on their satisfaction with company service and publishes the results of the survey on an annual basis. The 2000 report indicates that 88 percent of consumers surveyed were satisfied with the company's response to their calls concerning credit and collection matters, and 84 percent were satisfied with company responses to calls involving other matters such as contacts about trouble or power outages, billing matters, connect/disconnect requests, customer choice and miscellaneous issues. The survey as currently designed, however, does not address specific reliability concerns such as consumer satisfaction with company restoration of service after a power outage and satisfaction about company answers to questions about when power will be restored.[10]

The PUC staff members also obtain public input concerning company reliability performance during public input hearings. Such hearings, however, are usually held in conjunction with company requests for rate adjustments. With the establishment of caps on transmission and distribution rates, such hearings occur with less frequency as Pennsylvania implements deregulation of the electric power industry. Exhibit 10 shows for each major company the date when transmission and distribution caps will expire. For some companies, public hearings associated with rate reviews will not occur until 2005 or later.

[10]Consumer responses to these questions in one company's confidential surveys differed from the consumer responses on overall satisfaction on the company's BCS survey by 10 to 12 and 23 to 25 percent respectively.

Exhibit 10

Transmission and Distribution Rate Cap Expiration Dates, by Company and Source

PECO:

Transmission and Distribution – 12/31/06 (Merger Settlement Agreement)

PPL:

Transmission and Distribution – 12/31/04 (Restructuring Settlement)

Allegheny Power:

Transmission and Distribution – 12/31/05 (Restructuring Settlement)

GPU:

Transmission – 12/31/04 (Restructuring Settlement)
Distribution – 12/31/07 (FirstEnergy Merger Settlement Agreement)

Duquesne:

Transmission and Distribution – 12/31/05 (Provider of Last Resort II Settlement Agreement)

Penn Power:

Transmission – 12/31/04 (ATSI Settlement, Referenced in First Energy/GPU Merger Settlement)
Distribution – 12/31/07 (FirstEnergy/GPU Merger Settlement)

UGI:

Transmission and Distribution – 12/31/02 (Restructuring Settlement)

Source: PA Public Utility Commission.

C. *The PUC Has Not Established Adequate Reliability Performance Standards and Reporting Processes*

As required by statute, the PUC promulgated electric service reliability regulations in July 1998. The regulations require each electric distribution company starting in 1999 to file a report with the PUC[1] on or before May 31st of each year on the reliability of the company's distribution system.

PUC Reliability Reporting Requirements and Performance Standards

An annual reliability report must include:

- Assessment of electric service reliability for the company's electric distribution system and for operating area(s) designated by the company.
- Discussion of the company's programs and procedures for providing reliable electric service.
- Description of each major event, including the time and duration of the event, the number of customers affected, the cause of the event and any modified procedures adopted to avoid or minimize the impact of similar events in the future.
- Table(s) showing, for the most recent year and five preceding calendar years, for the company's distribution system (and operating areas), the performance indices required by the PUC to assess the reliability of company distribution systems. Currently, the Commission requires reporting of several reliability indices. Such indices provide information on the average:
    - Frequency of system interruptions (i.e.,SAIFI—System Average Interruption Frequency Index[2]).
    - Duration of system interruptions (i.e., SAIDI—System Average Interruption Duration Index[3]).
    - Interruption duration for those customers whose service was interrupted (i.e., CAIDI—Customer Average Interruption Duration Index[4]).
    - Momentary service interruption frequency (i.e., MAIFI—Momentary Average Interruption Frequency Index[5]).

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[1]Copies of the report must also be submitted to the Office of Consumer Advocate and the Office of Small Business Advocate.
[2]Calculated by dividing the total number of sustained customer interruptions by the total number of customers served.
[3]Calculated by dividing the sum of all sustained customer interruption durations, in customer-minutes, by the total number of customers served.
[4]Calculated by dividing the sum of all sustained customer interruption durations, in customer-minutes, by the total number of interrupted customers.
[5]Calculated by dividing the total number of momentary customer interruption by the total number of customers served.

However, based on our analysis, we concluded the PUC's reliability reporting and performance standards are not adequate to assure that the reliability of distribution systems does not deteriorate. Also, they do not provide a level playing field for companies reporting on their performance, and there is limited follow-up on company reporting. Specifically, as discussed below:

- PUC-established minimum reliability performance standards are, on average, significantly below company historic performance levels.
- Reported reliability performance data does not include all unscheduled service interruptions or information on the cause of such interruptions.
- Reliability performance information that is reported is not timely.
- Wide variations exist among companies in the minimum performance standards established by the PUC.
- Not all companies have taken steps to assure the PUC's performance levels and minimum standards remain relevant for assessing their reliability performance when making changes to their reliability data gathering systems.
- Companies can interpret Commission requirements in different ways when calculating their reported reliability performance.
- Limited review, monitoring, follow-up, and public reporting of company reliability performance have occurred to date.

The PUC's Minimum Reliability Performance Standards Are, on Average, Significantly Below Historic Performance Levels

PUC regulations require electric distribution companies to meet minimum reliability performance standards established by the PUC. In October 1997, the Commission initially proposed regulations requiring companies to have in place procedures to "sustain, at a minimum, the historic level of reliability and to improve service reliability when necessary."[6] The Commission's final regulations published in July 1998 did not include such a requirement, and the standards that were adopted allow companies to perform significantly below their historic levels.

On December 16, 1999, the Commission issued a final order setting forth its minimum reliability performance standards based on a proposal from electric distribution companies. The Commission established minimum reliability performance standards for each company at "two standard deviations" above[7] the company's prior five-year historic performance levels for each of the above reliability indices.

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[6]27 *Pa.B.* 5262.

[7]Often an increasing numeric value is considered a sign of improved performance. An increase in the value of a PUC reliability index, however, is not an indicator of improved performance. It is an indicator of diminished or "worse" performance.

In other words, an average company's reliability (as measured by the above indices) could deteriorate between 40 to 50 percent from its prior five-year average performance before the company would be out of compliance with the Commission's minimum performance requirements.[8]

Companies advocated for the position adopted by the Commission to assure they would not be penalized as a result of possible variability in their reported indices resulting from random year to year differences, especially differences in weather. The PUC accepted the companies' proposal indicating if company performance declined two standard deviations from historic performance levels:

> There is only about a 6 percent chance that this occurrence was due to the natural randomness of the index. In other words, there is a 94 percent probability that there has been a decline in reliability due to controllable circumstances, not other factors such as changes in weather conditions.[9]

Similar reasoning was advanced by utilities in Massachusetts, the only state listed in Appendix C[10] that has in place performance-based rates where fiscal penalties are automatically imposed when a company does not meet established performance standards. Massachusetts' fiscal penalties are triggered when a company's performance on a particular indicator is one standard deviation above the company's prior five-year average historic performance. The amount of the fiscal penalty increases from that point, with the highest financial penalty imposed for performance that is two standard deviations above the company's historic average performance (i.e., Pennsylvania's minimum performance standard). For companies with performance above two standard deviations, Massachusetts initiates formal investigations.

Massachusetts acknowledges that imposing financial penalties between one and two standard deviations above a company's historic average performance introduces the possibility (a 16 to 18 percent chance) that a utility could incur a financial penalty even though its actual performance was not inferior. Such a

[8]Because of statistical methods, the actual results for an individual company may be well below or above that of the average company.

[9]PUC order issued on February 11, 1999.

[10]New Jersey issued interim electric distribution service reliability standards that were effective January 2001. In its interim standards, minimum reliability levels for January 2001 for CAIDI and SAIFI are established at two standard deviations above each company's prior 10-year historic average performance on these indices. New Jersey established such thresholds because it required companies to implement specific outage management systems by December 31, 2000, and companies reported the newly required outage management systems would more fully capture reported outages and increase the values of the companies' reliability indices merely as an artifact of a new reporting system. With uniform outage management systems in place across companies, New Jersey may implement performance-based rates in 2003.

possibility arises primarily as a result of the limited number of years of data (i.e., 5 years)[11] used to establish the company performance standard.

Massachusetts, however, was unwilling to accept alternatives proposed by the utilities because they could result in the greater risk of the state incorrectly assuming a company met its standards when it did not. Massachusetts noted the utilities' proposal could mask as much as 30 percent degradation of service, and as such was inconsistent with the state's goal of ensuring adequate service.

Massachusetts noted that the possibility of a utility incurring a financial penalty due to random error is reduced when companies engage in routine activities intended to promote quality services. It also agreed that in a given year, it would "offset" a company's superior performance on one indicator with its inferior performance (i.e., between one and two standard deviations above its average historic performance) on another when imposing specific fiscal penalties.

Pennsylvania's electric reliability regulations, however, are not like Massachusetts', where significant fiscal penalties are imposed for failing to meet performance standards. Pennsylvania's regulations only provide for monitoring company performance; they do not impose penalties of any kind. Rather, they require companies whose reliability has substantially declined to submit additional information to the PUC in their annual reliability reports. The additional information includes:

- Analysis of the service interruption patterns and trends in the operating area(s) not meeting the minimum performance level(s).
- Analysis of the operational and maintenance history of the affected operating areas.
- Description of the causes of the unacceptable performance.
- Description of the corrective measures the electric distribution company is taking and target dates for completion.

The additional information companies must provide the PUC for the most part is a routine reporting requirement in other states. Illinois, Massachusetts, New York, and Ohio routinely capture such information in their planning and report submission requirements. Maryland and New Jersey, moreover, routinely require information and analysis of service interruptions for each of the company's poorest performing circuits. (Appendix C contains additional information on requirements in place in each of these states.)

[11]As shown in Appendix C, Massachusetts requires ten years of data, not five years, for purposes of reporting on reliability performance and other relevant information to assess such performance. Other important differences between the state's requirements for performance monitoring reporting and its performance-based rate setting reporting requirements are also noted in Appendix C.

The Office of Consumer Advocate (OCA) and others have also expressed their concern that the company historic performance levels used by the Commission to establish the minimum standards do not adequately reflect companies' historic performance. Initially, the Commission proposed having companies identify their historic performance levels and minimum performance standards using reliability data for 1993 through 1997. Subsequently, the Commission determined that companies should identify their historic performance levels using data for 1994 through 1998. OCA recommended the PUC base its company historic performance levels on data for 1993 through 1997. OCA reasoned that because several operating areas in 1998 did not meet the preliminary minimum performance standards established by the Commission using 1993-1997 data,[12] the Commission's use of 1998 data[13] to establish historic performance levels and minimum performance standards could result in the potential for further deterioration in service quality. The Commission decided to use 1998 data since 1998 was the most recent year prior to retail competition starting in 1999.

Ideally, to determine if company distribution system reliability has changed following Pennsylvania's 1996 deregulation/restructuring legislation, the Commission should have used reliability performance data prior to 1997 since Pennsylvania as part of industry deregulation/restructuring froze transmission and distribution rates as of January 1997. To reliably assess trends in prior performance, ideally 10 years of data should have been used, but was not available. As a result of the Commission's decision, two of the five years of data (rather than one of five) used by the Commission to identify historic performance levels and minimum performance standards reflect company performance after state legislation authorizing industry restructuring.

Reported Reliability Performance Data Does Not Include All Unscheduled Service Interruptions, or Information on the Cause of Such Interruptions

The reliability performance data routinely reported to the Commission does not account for all unplanned service interruptions. Companies in Pennsylvania do not routinely report on all unscheduled service interruptions for several reasons.

- The Commission's reliability and service outage regulations do not cover all unscheduled service interruptions, and the Commission has not

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[12]An August 16, 1999, Commission order notes that in 1998, six out of 30 single operating areas/single systems failed to meet the Commission's initial performance standard for CAIDI, and two failed to meet the initial standard for SAIFI.
[13]LB&FC staff analyzed the effect of the use of 1994 through 1998 data rather than 1993 through 1997 data on individual companies. We found all utilities did not benefit uniformly. For example, PECO, GPU, Allegheny Power, and Penn Power had to meet less stringent minimum performance standards for customer interruption duration, whereas PPL, Duquesne, and UGI had to meet somewhat more stringent standards using the 1994 to 1998 data.

required companies to report the causes of unscheduled service interruptions included in the reported reliability performance data.

- All of the major investor-owned companies are not able to report momentary service interruptions, and some that are able are not reporting them as required by Commission regulations and orders.

Service Interruption Reporting Not Covered in Regulations. PUC regulations permit companies to exclude "major events" from their reliability performance data. Major events are defined as service interruptions resulting from conditions beyond the control of the electric distribution company which affect at least 10 percent of the customers in an operating area for a duration of five minutes or longer. They also include unscheduled interruptions of service resulting from emergency load control and energy conservation to maintain the adequacy and security of the electrical system.[14]

Separate PUC regulations require companies to report unscheduled service outages that are expected to last six hours or more when the outage affects 2,500 or 5 percent of customers, whichever is less. They also require the company to report the reason for the service outage. These regulations, however, do not cover all of the "major events" that an electric company may exclude from its reliability performance reporting since all major events may not result in 2,500 customers without power for more than six consecutive hours. The PUC's service outage regulations, moreover, are designed to apply to all types of public utilities, not just electric utilities. They, therefore, do not capture the information necessary to calculate reliability performance associated with such events.

Several states require reporting of all service interruptions with detailed information on their causes. As shown in Exhibit 11, Illinois, Massachusetts, Michigan, and New York have comprehensive reporting requirements for all types of service interruptions and their causes. Maryland and Ohio require reporting of reliability performance data with and without major event data included in the calculations. As shown in Exhibit 11, some of the states, including New York and Illinois, gather data on the cause of service interruptions in ways that distinguish between those that are within the control of the company and those that are not.

The PUC's electric service reliability regulations require companies to maintain information on all outage causes; however, the Commission has not required companies to routinely report such information when reporting on their reliability performance.[15] As a result, the Commission lacks key information to monitor company performance when considering if interruptions are within or outside of the control of the utility.

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[14]Scheduled outages and service interruption to customers served under interruptible rate tariffs are not considered major events. Such outages, however, are not defined as sustained customer interruptions; and therefore, are excluded from reported reliability performance data.
[15]52 Pa. Code §57.194(g) and §57.195.

Exhibit 11

Selected State Reporting Requirements for Service Interruptions

- Illinois requires annual reporting of the number and duration of planned and unplanned service interruptions; the number and causes of controllable interruptions;[a] and customer service interruptions due solely to the actions or inactions of another utility, another jurisdictional entity, independent system operator, or alternative retail electric supplier. It requires a report on the age, current condition, reliability, and performance of existing transmission and distribution facilities, which include a summary of interruptions and voltage variances, and the reliability indices for the annual reporting period for such facilities. It further requires a list of the worst performing circuits for each company operating areas and the operating and maintenance history of circuits designated as worst performing.

- Maryland and Ohio require reporting of reliability performance data with and without major event data included in the calculation.

- Massachusetts requires companies to submit information for each major outage event excluded from its reported reliability performance data,[b] including the total number of customers affected, the number without service at periodic intervals, the time frame of longest customer interruption, the number of crews used to restore service on a per shift basis, and company policy on tree trimming, including tree trimming cycles, inspection procedures, and typical minimum vegetation clearance requirements. Massachusetts further requires reporting of every outage within one hour from its beginning if it results in 5,000 or more customer outage hours, or has a reasonable probability of involving a hospital, airport, large manufacturing, commercial, or institutional customer; and reporting of all other outages within 24-hours. Such reporting must include the date of the outage, its location, nature or cause, the number of customers affected, the time the outage commenced and the time service was restored, the duration of the outage, the number of customer outage hours, the feeder or circuit number, the district where the outage occurred, the identification of overhead or underground line where the fault or outage occurred, the number of crews involved in service restoration, and whether the outage is considered a major event.

- Michigan requires reporting of company success in restoring service to interrupted customers within specific periods of time during all operating conditions.

- New York requires monthly and year-to-date summary reports of service interruptions[c] for each company system and operating area. The report must include the number of interruptions by cause, total duration in customer hours of those interruptions, total number of customers affected, the average number of customers served during the period. Such information must be arrayed by cause categories that are defined in state regulations.[d] Such categories include major storms,[e] tree contacts,[f] overloads,[g] operating or working errors,[h] apparatus or equipment failures,[i] accidents or events not under the utility's control,[j] prearranged,[k] customer's equipment or failures,[l] lightning,[m] unknown, or unclassified.[n] New York also provides for narrative reporting of unusual events.[o]

Source: Developed by LB&FC staff.

Footnotes for this Exhibit can be found in Appendix D.

PUC staff recognize the need to refine reliability performance reporting requirements. They recognize the importance of gathering more complete information on unplanned service interruptions and the causes of unplanned interruptions. In a staff report, they have noted the limited causal information currently included in company annual reliability reports is "insufficient to draw any conclusions regarding trends in outage causes."

Momentary Interruption Reporting. The PUC's regulations require companies to report the frequency of momentary customer interruptions. Not all companies, however, have the technology in place to retrieve the information needed to report on such performance. The Commission, therefore, in April 1999 waived its reporting requirements for momentary interruptions for certain companies and replaced it with the requirement that companies with such waivers report any changes in their ability to collect momentary interruption data to the Commission as part of their annual reliability reports.[16]

The Commission did not waive its momentary customer interruption data reporting requirements for Allegheny Power, GPU, PECO, PPL, and Penn Power as these companies have the ability to provide such data. PECO, PPL, and Penn Power reported their frequency of momentary customer interruptions to the Commission in their annual reports on their performance in 1999 and 2000. Allegheny Power and GPU, however, have not fully complied with the Commission's reporting requirements. They have also not requested, or received a waiver of such regulatory reporting requirements.

During the course of this study, FirstEnergy acquired GPU. FirstEnergy staff advised the LB&FC staff that starting in 2002 the process of recording momentary events at GPU companies has been completely revised. FirstEnergy is currently putting procedures in place to collect momentary information from substations, field reclosing devices, and transmission supply events. Momentary

[16]The Commission in its order did not include all of the waivers required by companies to implement the electric service reliability regulations, or describe why such waivers are required or their duration. The order, for example, did not indicate that one small company was unable to exclude major events from its reliability performance data. The PUC, therefore, established and published performance levels and minimum performance standards for the company that include major event data. By informal agreement with CEEP, the company correctly reports all reliability data to the Commission with all major events included in the performance indicator. Another large company is unable to provide actual customer counts and relies on percent of load to identify when it is affected by a major event. The company disclosed this to the Commission when it submitted data to establish its historic performance levels and minimum standards. The Commission's order, however, does not specifically grant the company a waiver for such reporting, explain why it is needed, or the period for which the waiver is required. In addition, one other major company, because of the design of its systems, operationally defined a sustained interruption differently than PUC regulations, and another operationally defined a major event differently. One company subsequently modified its systems to report major events consistent with Pennsylvania regulations. The other company has not yet been able to make such changes. The PUC order did not provide the companies with waivers to operationally define sustained interruptions and major events differently than the definitions in Pennsylvania's regulations, or acknowledge that some companies would use different definitions in their annual reliability reports until such time as they made changes to their reliability data gathering and reporting systems.

operations from both transmission and distribution events are being collected. Since all momentary events affecting customers will now be recorded by the companies, FirstEnergy noted future momentary interruption counts will be higher than historic information available for GPU companies.

Reliability Performance Information Is Not Timely

The PUC's Bureau of Conservation, Economics and Energy Planning (CEEP) receives annual reliability performance data from companies mid-year of the subsequent calendar year. Companies, however, gather and report on reliability data internally, and in other reports to the PUC, on at least a monthly and year-to-date basis.

Significant diminishment of company reliability performance can occur over the 17-month period provided for by the PUC. The annual reliability reports submitted to the PUC, therefore, are of limited use for monitoring performance to assure that reliability is not diminished with deregulation/restructuring.

As noted above, New York requires reporting of all service interruptions by cause. Such reports must be filed monthly and include monthly and year-to-date information.

Wide Variation Exists Among Companies in Their Minimum Performance Standards Established by the PUC

Wide differences exist among the seven major companies in the variation between their company historic average performance levels and minimum performance standards. Table 2 shows the difference between the historic average performance level and the minimum performance standard for average customer interruption duration and average frequency of system interruption for the seven largest companies. As shown in Table 2, the difference between historic performance and minimum performance in terms of average customer interruption duration ranges from 18 to 80 percent for the seven largest companies, and for frequency of system interruption the difference ranges from 27 to 63 percent.

Table 2

Percent Differences Between the PUC's Historic Performance Levels and Minimum Performance Standards for CAIDI and SAIFI for Individual Companies

Company	CAIDI	SAIFI
PECO	29%	38%
PPL	21	30
Allegheny Power	25	61
GPU	25	46
Duquesne	18	27
Penn Power	26	40
UGI	80	63

Source: Developed by LB&FC staff.

Such variations result from the methods and data used by the PUC to develop its performance levels and standards for each company. For example, UGI, a relatively small utility, reported its average time to restore service to customers interrupted ranged from 96 minutes to 274 minutes between 1994 and 1998. This results in the company having a five-year historic performance level of 169 minutes and a minimum performance standard of 304 minutes. In other words, its minimum performance standard is 80 percent higher than its historic performance level. In contrast, PPL, one of the larger utilities, whose average service restoration times for interrupted customers is much more stable (ranging from 105 minutes to 141 minutes) has a minimum performance standard that is only 21 percent higher than its average historic performance level. Such wide variation across companies further confirms that the PUC's minimum performance standards alone are not effective measures for monitoring company reliability performance to assure that reliability is not diminished with deregulation and restructuring.

The Pennsylvania General Assembly when enacting legislation to deregulate and restructure the electric power industry attempted to assure that company service reliability did not diminish from historic performance levels. Companies whose historic performance levels are similar from year to year, therefore, are realizing the performance reliability goals referred to in statute. Such companies, however, have stricter minimum performance standards than companies whose performance fluctuated greatly from 1994 through 1998.

Not All Companies When Making Changes to Their Reliability Data Gathering Systems Have Taken Steps to Assure the PUC's Historic Performance Levels and Standards Remain Relevant for Assessing Their Reliability Performance

Several larger companies, including PECO, Allegheny Power, GPU, and Penn Power, have recently installed new outage management systems that are used to gather and generate the reliability data reported to the Commission, or they have made changes to their reporting systems. Once data are no longer gathered and collected in the same way, they can no longer be used for purposes of historic comparisons and trend analysis without certain information to account for data gathering differences.

PECO and Penn Power appear to recognize the importance of documenting changes in their reliability data gathering to assure that the PUC's historic performance levels and standards are relevant for considering company reliability performance. PECO, for example, introduced a new outage management system in 2001. PECO staff transitioned from one automated system to another in ways that allowed prior and current years reliability data to be compared through system implementation planning and analysis prior to and during the initial phase of the new system's implementation.

Penn Power had to modify the way it calculated its reliability information[17] and, when doing so, provided the PUC with sufficient data to determine if any changes to its historic performance levels and minimum performance standards would be necessary. When submitting its 1999 reliability data to the Commission, the company clearly indicated how reported reliability indices were calculated for each of the five years of data reported to the Commission. It also showed reliability performance data for one year using both its "old" and "new" operational calculations. In this way, the Commission could assess the effect, if any, of the changes on its established performance levels and minimum standards for the company.

GPU and Allegheny Power have introduced new outage management systems. They have suggested that their performance levels and standards are no longer relevant; however, they have not requested the Commission to consider if adjustments are required. Moreover, they have not provided data and information needed by the Commission to consider if adjustments are required and to make such adjustments.

As shown in Appendix C, some states (California and Massachusetts for example) have explicit requirements for company reporting of the information necessary to determine the effect, if any, on reported reliability data when changes are made in the way companies gather and report reliability performance data.

The PUC's electric service reliability regulations authorize the Commission to change the historic performance levels and minimum performance standards in cooperation with the companies and other affected parties. PUC staff members recognize that in view of the data provided by the companies and the introduction of

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[17]The company's reliability data for 1995 to 1998 excluded major events as defined by FirstEnergy's major storm definition, which differed from the PUC's definition of a major event. Subsequently, the company modified its reporting systems to capture major events in conformity with the PUC's definition.

new systems for gathering reliability performance data, the methodology used to establish company historic performance levels and minimum performance standards should be reviewed. During the course of this study, an internal working group was reviewing these and other issues related to reliability performance reporting.

Companies Can Interpret Commission Requirements in Different Ways When Calculating Their Reliability Performance

PUC regulations provide considerable flexibility to companies to interpret the Commission's regulations when excluding service interruption data from the performance data reported to the PUC. Flexibility is obviously needed. However, it can also result in companies calculating and reporting on their reliability performance in differing ways. This results in the Commission having distorted information on a company's performance and an uneven "playing field" for the reporting companies. When commenting on the PUC's proposed electric reliability regulations, companies brought to the Commission's attention the need for consistency in how they calculate their reported reliability performance and concerns about how such inconsistencies can lead to misinterpretations.

Three provisions in the PUC's electric service reliability regulations in particular can result in companies excluding service interruption data differently when calculating the reliability performance they report to the Commission. To date, the Commission has not clarified its understanding of such regulatory provisions, or identified criteria that must be met before companies exclude service interruptions from their calculations. The provisions include those involving:

- Other affected operating area exclusions.
- Designation of operating areas for reliability reporting purposes.
- Designation of when a major event begins and ends.

Other Affected Operating Area Exclusions. In its initially proposed reliability service regulations, the PUC did not permit companies to exclude performance data for operating areas unless 10 percent of the customers in the area were affected by the major event (as defined on page 42). The Commission's final regulations, however, indicate:

> When one operating area experiences a major event, the major event shall be deemed to extend to all other affected operating areas of that electric distribution company.[18]

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[18] 52 Pa. Code §57.192.

The PUC regulations do not define what is meant by "other affected operating areas," and the PUC has not issued an order clarifying this term.

In its comments on the Commission's proposed regulations, PPL identified situations in which companies require greater flexibility in identifying interruptions that qualify as major events. PPL recognized that major storms do not follow paths that exactly mirror a company's operating area boundaries, and, therefore, some operating areas even though they might experience the same storm, might not meet the PUC's 10 percent of customers requirement. PPL noted:

> When a major event affects one operating area and then moves through the electric distribution company's system affecting its other operating areas, the resulting interruptions for all affected areas should be excluded from the utility's overall reliability indices.

Others advocated for much broader company flexibility in excluding performance data during major events. GPU, for example, recommended:

> If one operating area in an electric distribution company experiences a major event, then the major event definition shall also apply to all the operating areas for the purpose of excluding the major interruption data from the calculations of the reported [reliability indices].

GPU advocated for flexibility similar to that in New Jersey. As shown in Appendix C, New Jersey is the only state that allows companies to exclude all system performance data from their reliability calculations when an operating area does not directly experience the major event but is providing assistance to an affected area and, with the New Jersey commission's permission, when the company is providing mutual aid to another utility.

The PUC stated in the preamble to its final regulation that it was accepting the modification to its definition of a major event as proposed by GPU and PPL. It did not, however, specify which company's proposal it was accepting.

Designation of Operating Areas for Reliability Reporting Purposes. The PUC's regulations allow companies to designate operating areas for use in reporting their reliability performance. Such designated areas then serve as the basis for calculating the number of customers affected by a major event and determining if a company can then exclude service interruption data from its reported reliability performance. The regulations, however, do not establish criteria that must be met for such designations. Examples of possible criteria include the company's historically defined service territories and number of customers served in the area.

As shown in Table 3, there is significant variation in the number of customers across company operating areas. Such variation can result in significant differences in the reliability data to the Commission. For example, GPU, using its broad interpretation of the PUC's definition of a major event, can exclude from its reports to the PUC performance data for its entire system of over 1 million customers when only 4,315 customers in Lewistown experience service interruptions. PECO and PPL, however, could not.

Typically, 25,000 or more customers would have to experience service interruptions in an operating area before PPL or Duquesne could exclude service interruption data from their reported performance. However, fewer than 9,000 customers on average would have to experience service interruptions before GPU could exclude service interruption data from its reported performance.

Designation of when a major event begins and ends. Companies also have considerable flexibility in how they operationally define when a major event begins and ends. The Commission changed its final service reliability regulations to indicate that a major event "begins when notification of the first interruption is received and ends when service to all customers affected by the event is restored." Thus, the number of unplanned service interruptions a company can exclude from its reliability performance data depends on when the company determines the event begins and ends. The PUC leaves this decision to the individual company. There is no requirement that companies rely on official weather records for such determinations, or other official reports companies are required to file with the PUC. Some companies, therefore, may rely on official weather information for such designations, and report service outage information consistently to the PUC. Others may not. Some companies, therefore, exclude more service interruption data than others when reporting their reliability performance to the Commission.

LB&FC staff reviewed the 2000 performance data reported to the Commission in May 2001 along with information reported on service outage reports that companies filed contemporaneously with the Commission. We found:

- One company (GPU) excluded service interruption data for nine major events in its 2000 reliability performance data.
- Four companies (PPL, Allegheny Power, Duquesne, and Penn Power) excluded performance data for only one major event.
- Two companies (PECO and UGI) did not exclude any performance data.
- All of the major events identified by PPL, Allegheny Power, Duquesne, and Penn Power were reported while the events were occurring to the PUC because of their scope and duration.
- GPU did not report four of its nine major events to the PUC while they were occurring. One of the major events GPU reported was "a storm with

rain and heavy winds" in the Reading area. Official daily weather records for that day, however, show no precipitation occurred in the area.

Table 3

EDC System and Operating Area
Number of Customers - 2000

System and Operating Area	Total Customers	10% of Customers
Allegheny-Northeast	86,050	8,605
Allegheny-Northwest	144,239	14,424
Allegheny-Central	202,708	20,271
Allegheny-Southeast	61,913	6,191
Allegheny-Southwest	191,310	19,131
Allegheny System	**686,220**	**68,622**
Duquesne-Northwest	264,344	26,434
Duquesne-Southeast	321,536	32,154
Duquesne System	**585,880**	**58,588**
GPU-Altoona	87,124	8,712
GPU-Clearfield	68,704	6,870
GPU-Easton	95,876	9,588
GPU-Erie	129,787	12,979
GPU-Hanover	70,743	7,074
GPU-Johnstown	99,449	9,945
GPU-Lebanon	61,962	6,196
GPU-Lewistown	43,146	4,315
GPU-Oil City	82,418	8,242
GPU-Reading	145,051	14,505
GPU-Towanda	70,307	7,031
GPU-York	121,394	12,139
GPU-System	**1,075,961**	**107,596**
PECO System	**1,520,521**	**152,052**
Penn Power System	**152,123**	**15,212**
PPL-Lehigh	306,312	30,631
PPL-Northeast	281,294	28,129
PPL-Susquehanna	226,646	22,665
PPL-Harrisburg	230,653	23,065
PPL-Lancaster	226,605	22,661
PPL System	**1,271,510**	**127,151**
UGI System	**61,571**	**6,157**

Source: Public Utility Commission.

- Operating areas with fewer than 10,000 customers triggered two of the nine major events GPU excluded from its reliability performance data; operating areas with fewer than 22,000 customers triggered three other major events. Moreover, when such events occurred, GPU excluded service interruptions on those days from its reported reliability performance data for its entire system of over 1 million customers.

All of the companies that excluded a major event from their 2000 reported performance data excluded service interruption data for a storm that occurred on December 12, 2000. There were, however, significant differences in how companies treated the same event.

PPL, for example, included in its annual reliability report the exact date and time the major event started and ended, along with detailed weather information. All of PPL's information in its annual reliability report is consistent with service outage reports it filed contemporaneously with the PUC. PPL reported the December 12, 2000, storm started at approximately 5:15 a.m. and the last customer affected by the storm was restored at 11:30 p.m. on December 13, 2000.

PPL also experienced a significant ice storm during the early morning hours of December 14, 2000, that affected about 30,000 customers on its system. PPL, however, did not treat the December 14th storm as a continuation of the December 12th major event. It, therefore, did not exclude the service interruption data for the December 14th event from the reliability data it submitted to the Commission.

PPL's service territory is contiguous with large portions of GPU's territory. GPU also reported that it experienced a major event on December 12, 2000. GPU, however, reported that the event extended through December 16th. GPU, therefore, excluded four days of service interruption data in the performance data it reported to the Commission, rather than the two days reported by PPL, Allegheny Power, and Duquesne. GPU did not include in its annual reliability report the exact time when the storm started, and it reported little information about the storm other than it involved high winds, snow, and ice.

The information GPU provided in its annual reliability report on the December 12, 2000, storm differs from the information GPU reported during the storm in the final service outage report it filed with the PUC. In the final report GPU filed with the PUC on December 16, 2000, the company noted it received its first report of service interruption for the December 12th storm at 1:30 a.m. and restored service to the last customer affected by the storm at approximately midnight on December 13, 2000. The service outage report makes no mention of an ice storm. In its annual reliability report, GPU combined the storm that started on December 14th with the separate storm of December 12th.

GPU and PPL also both experienced a storm involving lightning and rain on June 25, 2000. GPU reported the storm affected its Lebanon operating area from June 25 through 27th. GPU excluded from its reported performance all service interruption data for its Pennsylvania customers since 10 percent of the customers (6,444 customers) in its Lebanon operating area were affected. PPL's Lancaster operating area experienced the same June 25th lightning storm. PPL, however, included all service interruption data for this storm in the performance data it reported to the PUC.

The effect of the above reporting differences can be significant. For example, the PPL 2000 annual reliability report indicates that two of its four operating areas (Lancaster and Harrisburg) did not meet the PUC's established minimum performance standards for the average frequency of system interruption (SAIFI) performance in calendar year 2000. To determine if differences in company reporting practices affect the way the Commission assesses company performance, LB&FC staff requested PPL to recalculate its data to allow us to determine if the performance it reported to the PUC would have changed if it had considered the December 14, 2000, ice storm as a continuation of the December 12, 2000, major event and if it had treated the rain and lightning storm on June 25th as a major event.

Based on the revised data, LB&FC staff found:

- PPL's Harrisburg operating area would have performed better than the PUC's minimum performance standard for frequency of system interruption if PPL had treated the December 14th ice storm as a continuation of the December 12th storm when reporting to the PUC. The operating area would also have performed better than the PUC's minimum performance standard if only storm-related service interruptions for the June 25th storm had been excluded from the reported performance.
- PPL's Lancaster operating area would have performed better than the PUC's minimum performance standard for frequency of system interruption if PPL had treated the December 14th ice storm as a continuation of the December 12th storm and if all service interruptions (storm and non-storm) that occurred on the day of the June 25th had been excluded from its reported performance data.

The significance of excluding all system major event storm data from reported reliability data is also illustrated when storm data reliability data for GPU's Metropolitan Edison and Penelec are compared. Table 4 provides the difference between the company's reliability index with and without storm data included from

1999 through 2001. As shown in Table 4, the difference is more than 100 percent in some years for some reliability indicators.[19]

Table 4

Differences in Reported Reliability Indices for Metropolitan Edison and Penelec When All Storm Data Are Included

	CAIDI	SAIFI	SAIDI
Metropolitan Edison:			
1999	76%	33%	134%
2000	53	25	191
2001	27	23	41
Penelec:			
1999	5%	9%	15%
2000	59	47	127
2001	1	40	24

Source: Developed by LB&FC staff from company data.

LB&FC staff had questions about the GPU reliability data, and FirstEnergy attempted to provide information about the historical data submitted by GPU. FirstEnergy officials advised the LB&FC staff that the company is not able to document the accuracy of the historic reliability data reported by GPU. FirstEnergy stated, however, that it is committed to providing accurate and complete reliability data to the PUC. It is developing a common Outage Management System for all of its operating companies for implementation in April 2003. As part of the implementation of the new system, processes and procedures are being developed to assure the accuracy of outage statistics. Regional Dispatch Offices will be responsible for the accuracy of the data and will have procedures to release the data. The new system will automatically generate reliability reports by circuit. Dispatch, engineering, and line personnel will then review such reports to assure the reasonableness of the data.

FirstEnergy officials also advised the LB&FC staff that future annual reliability reports submitted for Penelec and Met-Ed will include the specific date and time for each major event that is reported. FirstEnergy indicated that GPU adopted its operating areas with the Commission's agreement, and that since that time when one operating area's outages qualified as a "major event," the major event was extended to the entire GPU Energy Pennsylvania system. FirstEnergy also advised the LB&FC staff that it is committed to working with the Commission to assure that reliability data reported by the former GPU data are accurate and in compliance with PUC regulations.

[19]In 2000, PPL's CAIDI reliability index increases by 4 percent when all major event data are included in the calculation; its SAIFI increases by 7 percent; and its SAIDI increases by 11 percent.

Limited Review, Follow-up Monitoring, and Reporting of the Reported Reliability Performance Data

The Bureau of CEEP is responsible for receiving and reviewing the annual reliability reports companies submit to the PUC. The Commission in its August 26, 1999, order directed the Bureau of CEEP to monitor company reliability and annually submit a report to the Commission on reliability performance based on each company's historic performance levels and minimum performance standards.

LB&FC staff reviewed the annual reliability reports submitted to the Commission by the seven largest companies. As noted above, we found inconsistency between the information reported to the Commission in annual reliability reports and other information reported to the PUC, and inconsistencies in how companies interpret reporting requirements. We also found:

- Companies all report performance reliability index values, but they do not all report the summary data they use to calculate the indices.

- Companies provide general information about their reliability programs, but not information sufficient to determine if the reliability programs they describe are being implemented.

- Companies whose performance is "below" the PUC's minimum performance standards do not all provide information sufficient to determine if the corrective actions they propose to address reliability problems are implemented and if the identified problem has been corrected, and if not, why not.

- Some companies whose performance is "below" the PUC's minimum performance standards did not provide specific information on the exact causes of the service interruptions that resulted in their inadequate performance.

The absence of information sufficient to allow the PUC to determine if companies are implementing their reliability programs as described is significant since the PUC is still in the process of implementing the statutory requirement that it establish regulations regarding inspection, maintenance, repair, and replacement standards for electric distribution systems.[20]

The PUC in the preamble to its final electric service reliability regulations noted that its reliability regulations did not include inspection and maintenance standards. The IRRC recommended the Commission reconsider the matter and

[20]66 Pa.C.S.A. §2802(20).

evaluate what other states have done or are doing regarding inspection and maintenance standards.

In the preamble to its final electric service reliability regulation, the PUC directed the Bureau of CEEP to study the issue of developing specific inspection and maintenance standards and to submit recommendations to the Commission for consideration. In December 2001, the Bureau of CEEP met with companies and initiated a study of inspection and maintenance practices and requested that they submit information on such practices by mid-January 2002. The Bureau is currently in the process of conducting the study.

As shown in Appendix C, states typically do not have specific minimum performance standards for inspection and maintenance programs that companies must meet, but they do have ongoing and detailed reporting requirements concerning such programs. In this way, the states are able to assess whether companies have reasonable inspection and maintenance programs, if they are implementing their programs, and if not, why not. Such information is routinely reported and is available for use by the state commission to assess the reasonableness of the programs and monitor company implementation, and actions to assure system reliability. California and Illinois, for example, also make such plans available to the public through their websites.

Based on calendar year 2000 reliability performance data, three (Allegheny Power, GPU, and Penn Power[21]) of the seven largest company systems performed below the PUC's minimum performance standards on one or more of the PUC performance reliability indices. The information provided by the PUC does not indicate that the Bureau of CEEP followed up with the companies based on such reported performance to better identify its cause and plans for correction.

With the introduction of electric industry deregulation, the PUC's Bureau of Consumer Services started to annually publish a new report on service quality—the *Customer Service Performance Report for Pennsylvania Electric Distribution Companies*. As noted in Finding B, this report is not intended or designed to assess specific reliability performance issues.

The PUC has not yet provided the public with information on company reliability performance. In 1999, companies took the position that the information in

[21]In August 2000, Penn Power submitted to the PUC more detailed information on its service reliability program. The information included the company's analysis of consumer complaints to the PUC's Bureau of Consumer Services, including complaints about service interruptions; the company's circuit reliability improvement plan; its distribution and operation and maintenance expense summary; a schedule for improvement to specific circuits and their anticipated engineering and construction completion dates; and a detailed description of the company's outage reporting and customer trouble call system. Penn Power subsequently filed monthly reports with the Bureau of Fixed Utilities on its progress in implementing a circuit program protection program in 2000 and 2001, and reported certain reliability performance data.

their reliability performance reports is confidential and proprietary. The Commission in its April 29, 1999, order, however, rejected this, stating:

> In a regulated monopolistic electric distribution industry, there are no other competitors. Moreover, an important policy goal that was to be met in restructuring the electric industry was the preservation of the integrity and reliability of electric service and the electric transmission and distribution system. In light of this goal, it would not be in the public interest to deny public access to this information.

The Bureau of CEEP has been working on draft reports summarizing company reliability performance in 1999 and 2000.

During the course of this review, the PUC formed an internal working group as part of its overall responsibility to address reliability and to ensure that current structures and requirements meet this obligation. The working group is comprised of members of Commission bureaus with direct and indirect responsibility for monitoring service reliability. Based upon internal review, the group tentatively identified several areas for further research and possible improvement. The working group has suggested:

- ➢ The methodology for establishing electric service reliability standards should be reviewed to determine if revision is needed to ensure higher levels of company performance.

- ➢ The Commission should review the definitions of a Major Event and an Operating Area under Chapter 57 to ensure consistent reporting of reliability performance by all EDCs.

- ➢ The current system for reporting service reliability performance should be modified to provide for more comprehensive and timely information.

- ➢ Internal communication within the Commission should be enhanced so that all persons involved with monitoring service reliability are current with all EDC reports and Commission activities.

On May 23, 2002, the Commission issued an order and directed its working group to submit no later than July 15, 2002, a detailed report on electric distribution reliability for consideration and further action. (A copy of the Commission's order is found in Appendix E.)

D. *Electric Distribution Reliability Appears to Be Diminishing in Some Areas*

LB&FC staff reviewed and analyzed the following data to assess the current status of reliability of Pennsylvania's major investor-owned distribution systems.

- Annual reliability data reported to the PUC for 1999 and 2000.
- Causes of sustained service interruptions from supplemental data submitted by companies and information reported to PEMA by local emergency management agencies and reported to the PUC on PEMA's Daily Report and PUC service outage reports.
- Consumer reported service reliability complaints.
- Service outage reports filed with the PUC during and immediately following extended unplanned service interruptions that include information on the number of customers affected by a storm, the total time from the first report of a customer service interruption to the time when the last customer was restored, and the total number of workers directly involved in restoration repairs.
- Most recent PUC management and operations and management and efficiency audits and the company's reports on the status of implementation of audit findings.

Status of Company Reliability Performance

Based on our review and analysis of the multiple sources of information available to the PUC, and discussed in detail below, we concluded:

- Reliability for three of the seven major investor-owned companies is similar to their historic performance levels, including one large company (PPL) whose reliability performance has remained relatively stable over the years after taking into account major storms that can affect reported performance. A second company (Duquesne), whose performance diminished in the early and mid-1990s initiated significant plans to improve its reliability performance after the PUC conducted special reviews of the company's performance during storm restorations. The results of company actions to improve its reliability are now reflected in the data recently reported to the PUC. The company's reliability improvement programs are continuing and it is now in process of reviewing recommendations for enhancement to its underground systems. The third company (UGI) is very small, which may account for the historic variability in its reliability performance data. The company, however, had no negative audit findings related to the reliability of its systems.

- Reliability for one of the seven appears to be improving after follow up by the PUC and aggressive actions by the company (PECO) to improve on its diminished performance in recent years. The company, moreover, has adopted company reliability performance standards more rigorous than those of the PUC's minimum performance standards.
- Reliability improvements to address diminished performance were introduced by one company (Penn Power). Such improvements are not yet reflected in the company's reliability performance data; and further improvements may be needed.
- Reliability for two of the seven companies (Allegheny Power and GPU) appears to be diminishing, and appears to be related to causes that are within the control of the companies. These companies, in addition to diminished performance on PUC reliability measures, have not always reported information as required on PUC service outage reports, they have negative audit findings that have not all been resolved, and they account for 33 of the 48 service interruptions reported to the PUC through PEMA that involve equipment failure. GPU, moreover, has adopted as its company's reliability performance targets the PUC's minimum reliability performance targets.

It is important to note that there may be a time lag between when distribution system improvements are initiated and when their results are reflected in improved performance. Some improvements may take as little as 10 months to implement, but their effect might not be reflected in performance data until the following year. Other improvements may take years to accomplish, and their influence on reliability performance, therefore, are not immediately apparent. Similarly, the effect of allowing distribution systems to slowly diminish might not be immediately reflected in reported performance data. In view of the length of time required to improve reliability once it has been allowed to diminish, it is important to closely monitor multiple sources of information on company reliability performance on a timely and continuous basis, and to follow up promptly on all indicators or signs of potentially diminishing reliability.

Reliability Performance Data for 1999 and 2000

Exhibit 12 shows the seven major companies' reliability performance in relation to the companies' historic performance levels from 1994 through 1998. Typically, companies in 2000 were performing at levels "the same" or similar to their historic performance. For purposes of analysis, we considered company performance to be "the same" or "similar" if its reported reliability performance was within

Exhibit 12

Company Reliability Performance for 1999 and 2000 Compared to 1994-1998 Historic Performance Levels

Company	Customer Average Interruption Duration (CAIDI)	System Average Interruption Frequency (SAIFI)	System Average Interruption Duration (SAIDI)
	Company Performance in Relation to the Company's Historic Performance*		
PECO	2000: Same	2000: Same	2000: Same
	1999: Worse	1999: Same	1999: Worse
PPL	2000: Same	2000: Same	2000: Same
	1999: Same	1999: Same	1999: Same
Allegheny Power	2000: Same	2000: Worse	2000: Worse
	1999: Same[a]	1999: Same	1999: Worse
GPU	2000: Worse	2000: Same	2000: Worse
	1999: Same	1999: Same	1999: Same
Duquesne	2000: Same	2000: Same	2000: Same
	1999: Same	1999: Same	1999: Same
Penn Power	2000: Same	2000: Worse	2000: Worse
	1999: Same	1999: Worse	1999: Worse
UGI	2000: Better	2000: Better	2000: Better
	1999: Better	1999: Same	1999: Better

*"Better" refers to performance where the company reported 25 percent or more improvement over its historic performance on the reliability index. "Worse" refers to reported performance 25 percent or more diminished from historic performance. "Same" refers to all other performance.

[a]The PUC's May 2000 audit report found Allegheny Power had lengthening service restoration times for interrupted customers. It based its finding on the PUC's initial reliability performance levels (data for 1993-1997). If LB&FC staff used the PUC's initial historic performance levels, Allegheny Power would have performed "worse" in 1999 than its historic performance.

Source: Developed by LB&FC staff from Pennsylvania PUC electric service reliability benchmarks for systems and data reported to the PUC for 1999 and 2000.

25 percent[1] (in either a positive or negative direction) of its average historic performance for 1994 through 1998. (Appendix F provides the 1999 and 2000 reliability index values and historic performance levels for each company.) As shown in Exhibit 12, however, there are some exceptions.

- In 1999 and 2000, Penn Power's performance was "worse" than its historic reliability performance for frequency of system interruptions (SAIFI) and duration of system interruptions (SAIDI). Its average duration of system interruptions was more than 50 percent "worse" than its historic performance level in both years.
- In 1999 and 2000, Allegheny Power's performance was "worse" than its historic reliability performance for duration of system interruptions (SAIDI). Its average duration of system interruptions was just under 50 percent "worse" than its historic performance level in both years. Allegheny Power's frequency of service interruption (SAIFI) was also "worse" than its historic performance in 2000.
- In 2000, GPU's performance was "worse" than its historic reliability performance for customer interruption duration (CAIDI) and system interruption duration (SAIDI). Its average customer interruption duration was almost 50 percent worse than the company's historic performance level.
- In 1999, PECO's performance was "worse" than its historic reliability performance for customer interruption duration (CAIDI) and system interruption duration (SAIDI). By 2000, PECO appeared to have reversed this downward trend, and was performing at historic performance levels on all PUC reliability indices.

Penn Power has been in the process of upgrading its distribution system, and reported to the PUC that certain planned upgrades were completed in 2001. Penn Power noted in its 2000 annual reliability report that four poor-performing subtransmission circuits in the New Castle area were responsible for its worsening frequency of system interruptions and system interruption durations. It also noted the transmission outages it experienced were caused by pole fires and the failure of company, and in some instances customer, equipment.

[1]We chose this threshold to allow for variability in year-to-year performance while recognizing that certain year-to-year variability has already been eliminated through the exclusion of service interruptions associated with major events from the reliability performance data. If we had considered company performance to be "the same" or "similar" if its reported reliability performance was within 20 percent (in either a positive or negative direction) of its average historic performance for 1994 through 1998, PECO's 2000 SAIDI performance would have been better than its historic performance, and Duquesne's CAIDI performance would have been better than its historic performance. Allegheny Power's historic CAIDI performance, however, would have been worse than its historic performance.

Allegheny Power reported for its system as a whole that the three leading causes of service interruptions were equipment failures, unknown causes,[2] and public/customers in 2000. For its two operating areas whose performance was worse than the PUC's minimum performance standards, the company reported equipment failures, unknown causes, and trees were the three leading causes of sustained interruptions.

GPU reported on the percent of customer minutes of interruption by cause for the six operating areas that did not meet the PUC's minimum performance standards. The three leading causes of sustained service interruptions in rank order were:

- other, unknown, and equipment in three areas;
- unknown, other, and equipment in a fourth area;
- unknown, trees, and other in a fifth area; and
- equipment, trees, and other in a sixth area.

Allegheny Power and GPU did not provide specific information on the equipment that failed and resulted in service interruptions. They primarily attribute their reported performance data to problems with the systems they introduced to gather reliability performance data. As described below, other sources of information about company reliability performance, however, demonstrate these companies have reliability problems that are not just an artifact of their data gathering systems.

2001 Reliability Performance

LB&FC requested, but not all companies provided, preliminary information on their reliability performance during 2001. Based on preliminary information provided by companies for 2001, it appears that PECO's and PPL's reliability performance in 2001 were similar to their historic performance levels. Duquesne had reduced its customer interruption durations and system interruption durations, and in 2001 performed better than its historic performance levels. Its performance on frequency of system interruption was similar to its historic performance levels.

UGI also reported on its 2001 performance. The company reported "worse" than historic performance for frequency of system interruption, and "better" than historic performance for other indicators. When considering UGI's reported reliability performance data, it is important to note that the company has a very small customer base and there are wide variations in the historic data the company reported

[2]This category includes air switch, capacitor, customer's equipment, guy, other, overhead wire, padmounted SW-Gear, pole, recloser, regulator, suspension insulators, transformers, and underground wires.

to the PUC to establish its historic performance levels, thus complicating interpretation of the performance data submitted to the PUC.

Penn Power's preliminary data for 2001 show improvements over 2000 performance in frequency and duration of system interruption. These reliability indicators, however, are still outside historic performance levels. This suggests that some of the improvements the company has introduced based on the improvement plan it submitted to the PUC are not yet fully reflected in the data, or that additional improvements may be needed.

FirstEnergy submitted preliminary 2001 reliability data for Metropolitan Edison and Penelec. It did not, however, submit data for the GPU system which previously was the basis for submission of annual reliability performance reports. With its acquisition of GPU, FirstEnergy plans to report reliability data for Metropolitan Edison and Penelec, but not the GPU system.

Causes of Service Interruptions

Additional understanding about the status of company service reliability is provided by information about the causes of company service interruptions. Such information is essential to assess if company actions can reduce the number and duration of interruptions and improve service reliability. In late 2001, the PUC requested companies provide this information on a one-time basis.

Supplemental Data From Companies. LB&FC staff analyzed company-reported service interruptions by cause from 1997 to 2000. We found:

- The total number of hours of interruptions[3] increased for six of the seven major companies, with four of the companies having 30 percent or more increases in their hours of customer interruption from 1997 through 2000.

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[3]On May 31, 2002, the PUC advised the LB&FC that the Bureau of CEEP had not provided us with customer hours of interruption for all of the seven major companies, and it would not be able to provide the correct data before mid-June 2002. Some of the companies had provided the PUC with indicators of interruption duration that were not based on customer hours of interruption. The PUC also advised the LB&FC staff that the duration times reported would increase for companies that did not report duration times in customer hours. The PUC also indicated it was obtaining customer hours of interruption data from all companies for use in its study of inspection and maintenance practices. The LB&FC's analysis of the causes of service interruptions is, therefore, based on hours of customer interruption only for PECO, PPL, and Duquesne. We do not think that the problems with the hours of interruption data provided by CEEP substantively alter our finding that service interruptions for the seven companies as a group are primarily caused by factors within the control of the companies. Our analysis of the volume of customers affected by service interruptions by cause in 1997 and 2000 confirms that the leading causes of service interruptions are within the ability of the company to influence. In 1997, equipment failure ranked second in accounting for the largest number of customers affected by service interruptions for the seven companies as a group. By 2000, it ranked first. In 1997, vehicles ranked third in terms of volume of customers affected by service interruptions. By 2000, vehicles were no longer in the top three causes of service interruptions for the seven companies as a whole.

- More than one-half of the leading causes for the increased hours of interruption for the seven major companies as a group were within the ability of the companies to influence (e.g., equipment failures). For each of the seven major companies, at least one of the three leading causes of increased hours of interruption is within the ability of the company to influence. For most companies, at least two of the three leading causes of increased hours are within the ability of the company to influence.
- The primary causes of the increased hours of interruption from 1997 to 2000 in rank order were equipment failure and overload, unknown and other, and non-controllable causes (including other-non controllable, vehicle, public, customer); inadequate tree trimming and company vegetation problems, and weather; animals; and construction errors.
- The primary causes of reduced hours of interruptions from 1997 to 2000 in rank order were fewer hours of interruption due to: equipment failure and improper design; trees; wind and weather; planned outages and loss of supply; operating errors; and "other" causes.

Daily Reports from Local Emergency Management Agencies to PEMA and PUC Service Outage Reports. The PUC also has available information about the causes of some service outages from the daily reports it receives from PEMA and its service outage reports. As shown in Table 5, in 2000, the largest number of outages reported to the PUC on service outage reports and to PEMA from local emergency management agencies involved weather events, as would be expected because of the requirements for PUC service outage reporting. The lowest number involved accidents, such as a car striking a utility pole.

During the first half of 2001, however, utility equipment or other problems accounted for the greatest number of outages brought to the attention of the PUC, with accidents again accounting for the least number. In both 2000 and 2001, two companies (Allegheny Power and GPU) accounted for roughly two-thirds or more of the PEMA-reported power outages involving utility equipment.

Consumer Service Reliability Complaints to the Bureau of Consumer Service (BCS)

The PUC receives complaints from consumers on an ongoing basis. As noted in Finding B, complaint trends do not in themselves confirm the existence of a problem or measure its dimension. They, however, are useful to identify the existence of possible problems and trigger further inquiries by PUC.

The LB&FC staff analyzed BCS data for specific complaints involving service reliability for 1994 through 1998, and 1999 and 2000, the most recent data available.[4] As shown in Table 6, frequency of service interruptions, monetary damage

[4]The latest data available to the PUC and the LB&FC staff.

Table 5

2000 and 2001 Outages Reported to the PUC or to PEMA

	2000					2001				
EDC	Weather	Accident	Utility Equipment or Other Problem	Cause Unreported	Total	Weather	Accident	Utility Equipment or Other Problem	Cause Unreported	Total
PECO	4	2	2	0	8	2	0	2	0	4
PPL	8	0	2	5	15	1	2	5	3	11
Allegheny Power/ West Penn	5	2	5	3	15	4	3	10	6	23
GPU	8	3	9	12	32	6	4	9	2	21
Duquesne	4	0	0	0	4	1	0	1	1	3
Penn Power	3	0	0	2	5	0	1	2	0	3
UGI	0	0	0	0	0	1	0	1	0	2
Total	32	7	18	22	79	15	10	30	12	67

Source: Developed by LB&FC staff from reports of service outages submitted to the PUC and PEMA daily reports. Note that some counties may seek assistance from PEMA more frequently than others and that PEMA data for 2001 are only for the first six months of 2001. Data exclude all reports related to power generation problems or planned generation plant closures. If the outage involved a report both to the PUC and to PEMA, such an outage was counted as one.

Table 6

Average Annual Numbers of Complaints Reported to the PUC's Bureau of Consumer Services for Major Companies

Complaint	PECO		PPL		Allegheny Power		GPU		Duquesne		Penn Power		UGI	
	1994 to 1998	1999 to 2000	1994 to 1998	1999 to 2000	1994 to 1998	1999 to 2000	1994 to 1998	1999 to 2000	1994 to 1998	1999 to 2000	1994 to 1998	1999 to 2000	1994 to 1998	1999 to 2000
Frequency of Service Interruption	27.8	60.0	8.4	21.0	11.8	14.5	11.5	75.0	22.6	36.5	4.6	11.5	0.6	0.0
Duration of Service Interruption	10.6	35.5	3.6	6.5	5.0	4.5	3.4	26.5	12.6	10.0	3.0	6.0	0.2	0.5
Unsatisfactory Service – Company Problem (High/Low Voltage, etc.)	13.2	24.0	3.8	8.0	4.6	3.5	2.8	14.5	2.8	9.0	1.4	1.0	0.6	0.0
Safety – Equipment, Location of Facilities and Other (i.e., Construction/Repair, and Unsafe Wires and Poles, etc.)	12.2	38.0	2.8	11.0	2.0	7.5	1.5	5.5	3.0	5.0	0.0	0.5	0.0	1.5
Service Interruption (abandonment, blackout, brownout)	0.6	2.0	0.2	0.0	0.4	0.0	0.25	0.5	0.0	0.0	0.0	0.0	0.2	0.0
Monetary Damage From Quality of Performed Service	22.8	25.5	7.8	8.5	15.8	16.0	8.8	14.0	15.4	6.5	3.0	0.5	0.8	0.5
Property Damage From Quality of Performed Service	7.8	19.0	3.6	4.5	5.8	7.0	2.3	5.5	4.8	15.0	2.2	1.0	0.0	0.0

Source: Developed by LB&FC staff from PUC BCS database.

from quality of service performed, high voltage/low voltage problems, duration of service interruption, and safety problems, including unsafe wires and poles, are the types of reliability complaints most frequently reported to BCS.

The increase in the average annual reliability complaints to BCS is similar to the increase in total complaints for the same periods. From 1994 through 1998 and 1999 through 2000, the average annual number of total complaints to BCS increased 108 percent (from 2,037 on average annually to 4,246), with reliability complaints accounting for about 13 percent of total complaints during both periods.

As shown in Table 7, however, there are differences among the companies in the relative volume of BCS complaints that are due to consumer reliability problems. Penn Power had the largest percent of complaints to BCS accounted for by reliability problems during both periods, while PPL had the lowest. GPU had the largest increase in the percent of its BCS complaints accounted for by reliability problems from 1994-1998 through 1999-2000.

Hurricane Floyd, a major storm that occurred in September 1999, accounts in part for GPU's increase in reliability complaints as a percent of its total complaints. Complaints about the frequency of service interruption and duration following Hurricane Floyd (September and October 1999) were responsible for 23 percent of all of GPU's reliability complaints in 1999. Such complaints also accounted for a relatively high proportion of 1999 reliability complaints for the other companies that experienced Hurricane Floyd, including PECO (18 percent), PPL (27 percent), and UGI (33 percent). However, PECO's, PPL's, and UGI's reliability complaints as a percent of total complaints either declined or remained the same from 1994-1998 to 1999-2000.

Table 7

Reliability Complaints as a Percent of Total Average Annual Complaints to BCS

Company	% of Reliability Complaints 1994-1998	% of Reliability Complaints 1999-2000
PECO	12%	12%
PPL	9	6
Allegheny Power	20	16
GPU	9	19
Duquesne	21	23
Penn Power	33	33
UGI	10	7
Total BSC Complaints	13.6	13.2

Source: Developed by LB&FC staff from BCS complaint data.

Service Outage Restoration Performance

From the perspective of customers, the ability of companies to respond to customer service outages during storms is an important indicator of company service reliability. When transmission and distribution systems are allowed to diminish, such systems are not resilient. When service interruptions then occur, customer service is not restored in a timely manner.

The PUC's service outage reports are an important source of information available to the PUC to monitor company performance. As noted in Finding B, PUC regulations require companies to immediately report to the PUC all unscheduled service outages involving 2,500 or 5 percent of its customers, whichever is less, projected to last six or more consecutive hours and identify the information companies must report. The regulations require companies to report the reason for the outage, the number of customers affected; the projected time for restoring service to customers; the time when the first service interruption occurred, when service to the last customer was restored; and how many workers from the company, contractors, and other utilities were involved in repair work and when they started repairs. In addition, the reports allow companies to provide descriptive information relevant to special circumstances that extend the service restoration times.

LB&FC staff reviewed the service outage reports the seven major investor-owned companies submitted to the PUC. We found, for example, that as recently as 2000 and 2001, some of the companies were not reporting all of the required information to the PUC.

- Allegheny Power submitted reports in 2001 that lacked information on the number of utility and other workers specifically assigned to repair work.
- GPU reports lack information on the total number of customers affected.

Appendix G shows the number of service outage reports submitted to the PUC by each company over time and the number of reports with complete and missing information.

Consistent reporting of service outage data is important because such reports can highlight possible performance problems and point to the need for follow-up by the PUC. The reported data, however, does not in itself necessarily explain the cause(s) of the service outages and extended restoration times. Extended restoration times may be due to a variety of factors, including the design of the company's system and its age, inadequate preparation by the company to respond to an expected storm, limited numbers of workers involved in storm repairs, failure of the company to complete necessary system maintenance in a timely manner, major equipment replacement problems, the location of equipment that failed, and the severity of the storm itself (i.e., a major hurricane).

The information available on service outage reports for reporting companies, however, illustrates how service outage reports can be used for reliability monitoring. Table 8 shows for winter and non-winter storms the date and time of the first customer service interruption and the total lapsed time until the last customer was restored. The table also shows the number of customers affected by the storm and the number of customers per repair worker.

As shown in Table 8, the longest service interruption storm duration experienced by PECO customers from 1992 through 2001 occurred with the May 31, 1998, storm. The number of customers affected by the storm was also the largest in the company's history (based on data reported in the PUC service outage reports). The service outage report notes that the cause of the service interruption was high winds, lightning, local tornadoes, and tree-related damages. The closest similar storm reported on company service outage reports occurred on September 27, 1993, when the company's system was struck by strong winds, lightning, heavy rain, and localized tornadoes.

PECO originally advised the PUC that its last affected customer would be restored by June 3rd at 12:00 a.m., and then revised its projection to June 4th at 12:00 a.m. However, the last customer was restored on June 4th at 10:45 p.m.—almost two days later than PECO's initial projection.

PECO noted in press releases that during the storm repair workers replaced 30 miles of aerial power lines, 400 utility poles, 1,100 crossarms that hold power lines atop poles, 65 transformers, and countless fuses. Company workers, contractors, and other utilities from Connecticut and Virginia completed the work.

PECO reported different numbers of repair workers in final reports to the PUC. Initially, it indicated that 700 workers were involved in repair work. It later reported 1,114 repair workers. The company indicated that 700 workers were initially involved in repairs, but over a multiple day period the cumulative total was 1,114 workers. Based on the company's reported service outage data, if 700 workers were involved, there were fewer repair workers per affected customer during the May 31, 1998, storm than any other storm the company reported to the PUC. If 1,114 repair workers were involved, the May 31, 1998, storm had fewer repair workers for every customer affected than all but two other storms in the company's history. Despite the severity of the May 31st storm, the service outage data clearly raised questions about PECO's ability to adequately respond during major service outages.

The PUC notified the company that it was initiating an informal investigation of the company in May 1999 as a result of the company's performance during the one-day March 14, 1999, storm. As shown in Table 8, this storm accounts for the longest lapsed time of service interruption for any winter storm in the company's history (based on data reported in the PUC service outage reports) with the exception of a major three-day storm in December 1992.

Table 8

PECO Service Interruption
Total Lapsed Times for Winter and Non-Winter Storms
(1992-2001)

Date of Event & Time of First Interruption Report	Total Service Interruption Lapsed Time in Minutes	Total Customers Affected	Customers Per Repair Worker
Winter Storms:			
12/10/92 8:00 p.m.	5,962	184,171	204
3/14/99 2:45 p.m.	3,782	161,535	239
11/2/99 6:45 p.m.	3,102	122,882	202
3/13/93 6:00 a.m.	2,940	80,094	102
11/11/95 7:00 p.m.	2,700	80,600	164
3/4/93 11:57 a.m.	2,403	88,641	112
1/18/99 9:55 a.m.	2,360	87,107	221
12/12/00 6:30 a.m.	2,130	102,860	193
1/2/99 11:55 p.m.	2,045	49,174	264
1/19/96 11:00 a.m.	1,500	80,500	230
12/17/00 2:52 a.m.	1,268	53,255	355
3/6/97 5:00 a.m.	1,020	54,106	193
Non-Winter Storms:			
5/31/98 11:54 a.m.	6,411	331,600	298
7/4/99 11:39 a.m.	6,221	93,684	196
9/27/93 3:00 p.m.	3,675	156,099	137
6/30/98 6:02 p.m.	3,433	186,700	249
8/26/99 2:33 a.m.	3,207	131,588	236
9/7/98 12:55 p.m.	3,140	90,655	192
6/26/98 12:12 p.m.	3,074	151,000	258
6/12/96 3:45 p.m.	2,655	63,233	357
6/16/01 10:57 a.m.	2,553	66,318	137
7/17/95 8:00 p.m.	1,560	49,246	145
7/19/99 4:45 p.m.	1,530	41,045	304

Source: Developed by LB&FC staff from PUC service outage reports.

The storm outage reports for PPL also illustrate the usefulness of the reports for assessing the consistency of company storm restoration practices. PPL has established company targets for customer restoration during winter and summer storms, and performance in relationship to such targets affects compensation. The company also has strategic plans in place to assure timely restoration of service to customers, and a functioning outage management system that allows it to quickly identify location and outage causes.

As shown in Table 9, the longest service interruption lapsed time for PPL customers occurred in September 1999 as a result of Hurricane Floyd. More PPL customers were affected by the hurricane than any other storm (reported to the PUC on service outage reports). PPL consistently provides detailed information in its reports to the PUC. The report for the September 16th storm notes the company's preparation in advance of the storm, the contractors and other utilities enlisted in advance to provide restoration assistance, and the company's unsuccessful attempts to secure additional assistance from other utilities because of the widespread nature of the event.

Table 9

PPL Service Interruption
Total Lapsed Times for Winter and Non-Winter Storms
(1992-2001)

Date of Event & Time of First Interruption Report	Total Service Interruption Lapsed Time in Minutes	Total Customers Affected	Customers Per Repair Worker
Winter Storms:			
12/10/92 10:00 p.m.	3,001	137,755	122
1/28/94 3:00 a.m.	2,701	28,143	55
12/12/00 5:15 a.m.	2,535	93,824	123
11/2/99 4:30 p.m.	2,250	76,399	133
3/13/93 12:00 p.m.	2,159	40,400	76
3/4/93 3:00 p.m.	1,980	152,000	138
3/14/99 2:00 p.m.	1,950	57,030	150
12/14/00 2:30 a.m.	1,080	28,304	106
Non-Winter Storms:			
9/16/99 12:30 p.m.	5,730	392,382	318
8/13/99 5:30 p.m.	3,150	39,870	111
7/10/92 5:30 p.m.	3,030	25,547	122
7/16/95 12:01 a.m.	2,879	100,000	244
5/13/00 5:15 p.m.	2,715	41,195	108
6/30/98 2:00 p.m.	2,455	60,157	125
6/2/00 4:30 p.m.	2,385	31,831	100
9/7/98 10:30 a.m.	2,251	49,332	146
7/6/94 5:50 p.m.	1,800	53,550	97
4/9/95 6:00 p.m.	1,799	35,491	80
6/25/00 5:00 p.m.	1,635	21,428	126
7/1/01 4:40 p.m.	1,625	26,078	77
6/11/00 6:00 p.m.	1,590	31,529	143
7/15/92 2:30 p.m.	1,470	39,278	91
5/18/00 4:30 p.m.	1,410	25,281	92

Source: Developed by LB&FC staff from PUC service outage reports.

The second longest service interruption duration for PPL occurred with an August 1999 storm. The report notes that restoration was extended because of difficulty accessing the trouble location.

Recent PUC Audits and the Status of Company Actions in Response to Audit Findings and Other Publicly Available Information

The PUC's Bureau of Audits has completed several audits since state legislation provided for the deregulation/restructuring of the electric power companies. Traditionally, the Bureau has focused on service reliability and safety in its audits, and this practice has continued. Several of the PUC's audit findings and the company responses to PUC audit recommendations provide important information on the status of company distribution system reliability. The following is a summary of key information reported in PUC audits and other publicly available documents.

PECO. The PUC audit staff initiated a statutorily required management and operations audit in 1998 and conducted two special studies concerning PECO's responses to service outages in 1998 and 1999. The Commission released the bureau's 1998 management and operations audit to the public in August 1999. The Commission also made public key information from the Bureau of Audit's special study of 1999 service outages in January 2002 when it approved a settlement agreement between PECO and the PUC Law Bureau concerning allegations regarding inadequate service during 1999 service outages.

The PUC's 1998 management and operations audit (released in August 1999)[5] found that PECO's planned personnel reductions, especially for craft/technical support staff, may have an impact on future service reliability performance. The PUC audit recommended the company monitor the effects of ongoing transmission and distribution staff reductions and other cost saving initiatives on system reliability and adjust staffing and other resources as necessary to maintain compliance with the company's historic performance levels.

From publicly available reports, it appears that PECO was not able to implement the PUC's recommendation in a timely manner. One local newspaper, for example, editorialized in response to storms occurring in the first half of 1999 that "PECO must do a better job of storm recovery." The editorial noted PECO reduced its workforce from 11,000 in 1990 to 7,000 in 1999. The editorial went on to question: "if the company, anticipating the stresses of competition, didn't cut things too close to the bone." The January 2002 settlement agreement, moreover, requires PECO to provide 29 additional service outage restoration personnel above the total the company projected for 2001 and 2002.

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[5]Actual audit field work started in August 1998 and continued intermittently through April 1999.

In addition, PECO, as part of its June 2000 merger settlement agreement, committed to implementing a quality of service plan. As part of the plan, PECO agreed to:

- continue efforts to resolve reliability problems identified in York County, several suburban Philadelphia townships, and the City of Philadelphia;
- achieve higher levels of reliability performance than required by the PUC (i.e., by 2005 to achieve a 10 percent higher level of performance for customer service interruption duration and frequency of system interruption.);
- provide parties to the settlement agreement with an annual plan to reduce the number of customers with repeat outages and report on its performance in reducing such outages;
- provide a higher level of service for its five worst performing circuits and annually report on the results of such efforts; and
- provide the Commission, the Office of Consumer Advocate, and the City of Philadelphia with reports on its performance in restoring service during individual storms that are excluded from the company's annual reliability report.

LB&FC staff found PECO started to work to improve its service reliability after difficulties in responding to storms in 1998. Since July 1998, PECO issued at least 38 news releases describing its efforts to improve service reliability. PECO had adopted more stringent internal reliability standards than those imposed by the PUC for its operations, and its efforts in the past several years to improve its distribution reliability appear to be reflected in recent data on its performance (see Exhibit 12). In its annual reliability report for calendar year 2000, PECO summarized the actions it had been taking since 1998 to improve it customer interruption duration times. Such actions included:

- installation of a new outage management system that will provide up-to-date graphical representations of the distribution system, automatic interruption analysis, and enhanced tools for management of field resources;
- incentive compensation that is contingent on reducing customer interruption duration;
- operational improvements, including relocation of first-response personnel, optimization of dispatch areas, streamlined work assignment processes, and greater availability of special equipment used to accelerate restoration; and
- removal of hazardous trees.

PECO attributed its improved service reliability in 2001 to "aggressive maintenance programs, effective tree trimming, strategic investments, and less storm activity." It also attributed improvement in its customer service interruption restoration times to a 20-point plan to restore service faster. The plan included installing equipment to help isolate the cause of the outage and reduce the number of customers affected, enhancing staffing schedules, and providing additional training and performance incentives for employees. More recently, in March 2002, the company announced that it was making additional reliability improvement investments. It was investing:

- $41 million in 2002 for new and expanded electric substations, equipment upgrades on local circuits, and reconfiguration of circuits in growing communities to better balance electric distribution on the circuits;
- $30 million for preventive and corrective maintenance, including patrols of its 2,200 distribution circuits, equipment inspection using infrared cameras, and replacement of transformers, cables, and other facilities;
- $18 million for tree trimming along aerial power lines to prevent interference, especially during storms; and
- $27 million to enhance service in targeted areas through retirement of older substations, replacement of circuit breakers, and installation of more lightning arresters, circuit sectionalizers, and reclosers. (Such devices pinpoint and isolate trouble on the system to reduce the number of customers affected by incidents such as vehicle accidents, animal interference, and equipment failures.)

From our contacts with PECO, we know it maintains detailed information on the causes of service interruptions and monthly data on its reliability performance. It uses such analyses to develop strategies to improve reliability performance and target reliability improvement investments.

PPL. The PUC has not released an audit of PPL since deregulation/restructuring was enacted in Pennsylvania. As of February 2002, the Bureau of Audits had completed a management and operations audit and a draft of the audit findings was under development.

Allegheny Power/West Penn. In May 2000, the PUC released the Bureau of Audit's most recent focused management and operations audit of Allegheny Power/West Penn Power. The audit was conducted from September through December 1999. The report included several relevant findings and recommendations.

Affiliate Agreements. The PUC audit noted that the Pennsylvania utility (referred to as West Penn) was no longer a separate operating company. Rather, it had become part of Allegheny Power—a single operating company providing electric services in five states, including Pennsylvania.

The PUC audit found that Allegheny Power's parent corporation had introduced organizational changes that resulted in the Allegheny Power/West Penn receiving transmission and distribution operations and maintenance services previously performed by West Penn employees through a parent company affiliate arrangement. None of these relationships, however, had been documented as required by state law[6] in an affiliated interest agreement filed with the PUC. As a result, there were no agreements setting forth the extent of goods and services, and their costs, provided to Allegheny Power/West Penn by the parent company affiliate that had been approved by the PUC. By 1998, moreover, affiliate charges were accounting for 94 percent of West Penn's total operation and maintenance expenses for transmission and distribution, customer accounts and service, and administrative and general expenses.

The PUC recommended that the company file the required affiliated agreements with the Commission. The company accepted the recommendation, indicating that such documents would be filed by October 2000. As of June 2001, the matter was still pending.

Linemen Used as Meter Readers. The PUC audit found that the company was inefficiently using linemen for meter reading functions to compensate for low staffing, especially in the State College Service Center, and recommended the company evaluate the efficiency of this practice. The company accepted the PUC's recommendations indicating linemen would be used for meter reading only under limited circumstances,[7] temporary meter readers were in place as of June 2000, full-time meter readers would be hired and required work practice changes would be in place by the end of 2000.

Untimely Analysis of Service Interruption and Reliability Performance Data. The PUC audit found the company was not analyzing its service interruption and reliability data in a timely manner, and the company's way of categorizing service interruption was inadequate. The audit noted the company historically analyzed its interruption and reliability data on an annual basis during the first quarter of the subsequent calendar year. Since 1995, however, the company has not analyzed service interruption and reliability data until the fourth quarter of the subsequent calendar year. In other words, the company took more than a year to analyze its prior reliability performance, thus significantly lengthening the time before corrective measures could be taken to address the primary causes of the interruptions.

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[6] 66 Pa. C.S.A. §2102.

[7] The exception to this is the "Linemen and Utilitymen" position. The company reported this position performs meter reading as a portion of its regular duties.

The audit also found that the company's service interruption categories were not adequate to identify and analyze service interruptions to underground plants. The company, moreover, had not changed its service interruption reporting categories to reflect the fact that most of its new business was underground work.

The PUC audit recommended the company analyze calendar year service interruption and reliability data no later than the end of the first quarter of the subsequent year. It also recommended that the company modify the causes of service interruptions captured in its reporting systems.

During the course of the audit, the company advised PUC staff that the company's new Outage Management System would be fully operational by the first quarter of 2000. The company reported the new system would enable it to compile interruption and reliability data for analysis during the first quarter of the subsequent calendar year and would allow the company to add descriptors to better analyze the causes of service interruptions.

The company accepted the PUC's audit recommendation and indicated such changes would be in place by November 2000. In June 2001, the company reported to the PUC it had completed implementation of the recommendation and that the implementation of the new Outage Management System enhanced its ability to evaluate outages and their cause and frequency. It noted that it posted such information on a monthly basis throughout the company, and that the company routinely utilized the information for evaluating distribution circuit performance.

Lengthening Customer Interruption Durations. The PUC audit found since 1996, the company's average duration of customer interruptions had been above its historic performance level and close to the PUC's minimum performance standard.[8] It reported the company had fewer system interruptions, but was taking longer to restore services to customers affected by interruptions that did occur.

The PUC audit noted there are several possible reasons for the increase in the company's average duration of customer interruptions. Analyzing company data on customer-minutes of interruption by cause, the PUC reported possible causes included transformers, public-related interruptions, lightning, miscellaneous known causes, and wire and cable. The PUC audit noted that for each of these possible causes the number of incidents and number of customers affected by the incident had declined, but the average time to restore service to affected customers had increased.

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[8]The PUC audit finding is based on PUC historic performance levels and minimum performance standards that relied on 1993-1997 data and were issued by the PUC in February 1999. The Commission subsequently revised its historic performance levels and minimum performance standards to use 1994-1998 data. Such changes occurred in late December 1999 after audit fieldwork had been completed.

Company workers commenting on this PUC audit finding noted that the number of customer interruption minutes related to transformers, lightning, and wire and cable could be reduced. They described company practices that can increase the duration of customer service interruptions associated with such causes.

They noted that Allegheny/West Penn installs only single busing transformers for all residential customers. These transformers have an internal fuse. If the fuse fails because of a fault condition, the transformer must be physically changed. Such changes require at least two qualified primary linemen/servicemen, according to company workers. They reported that the company's call center in Fairmont, West Virginia, usually receives calls for such interruptions. The center in turn calls out one worker. That person reports to the service center, gets tools and a truck and proceeds to the reported location of the interruption. When the worker finds a bad transformer, the worker must then ask for a second person to be called out in order to replace the transformer. This can add at least an hour to the customers' outage duration, and more if the outage occurs at night.

Company workers reported that Allegheny Power's lightning arrestors do not get replaced in a timely fashion. Lightning arrestors provide one time protection, and must be replaced after being hit by lightning, or the next strike will go out onto the distribution system and cause damage.

Company workers also reported that outages on underground lines have been increasing, in part due to the increase in underground installations. They also expressed the view that more underground wire maintenance is required along with more on-site monitoring of those contracted to complete digging and backfilling. Without such quality controls, contractors might not backfill with rock free soil or approved sand or assure that warning tape is installed at the proper depth to alert anyone digging in the area at a later time. They note this is particularly important for the company's system because it still installs primary wire by direct burial methods rather than encasing it in a conduit.

The PUC audit noted that the company had not analyzed its response times during normal business hours to determine which steps in the restoration process contribute to lengthy service interruptions. (Such an analysis had only been performed for service interruptions occurring after normal business hours.) The PUC audit further acknowledged that Allegheny's increased customer service interruption durations could be due to linemen and servicemen staffing levels and potential problems with the company's historical data for the period 1996.

The company reported to PUC auditors that during 1996 and 1997 several months of reports of service interruptions were not tabulated because the reports that were submitted were incomplete. The company, however, assured the PUC auditors that the company had "since changed its reporting mechanism to ensure the accuracy of the 1998 interruption and reliability data."

The PUC audit recommended the company implement corrective measures to achieve and maintain its historic reliability performance levels, and the company accepted the PUC's recommendation. In June 2001, the company reported it had provided training during 2000 to service centers, dispatching, and customer service center managers to enter the correct date and time of restoration into its Outage Management System, and as a result, its customer average interruption duration reliability performance had improved in 2000.[9]

The company also noted that it was opening a new service center in October 2001 based on the results of a logistic study. Customers served by the new service center could anticipate having their average interruption durations reduced by 30 minutes simply as a result of reduced company staff travel time. The company further indicated it would continue to monitor its service reliability.

Despite company assurances and the steps the company took to address reliability reporting problems, the company reported to the PUC in its 2000 annual reliability report that there were problems with the reliability report data collection methods used throughout 1998. The company indicated the data reported for calendar year 1999 and 2000 were from its new Outage Management System, and that it had not anticipated the significant changes in its reported reliability indices as a result of the new system.

The company did not explicitly advise the PUC in its 1999 or 2000 reliability report, or in its reports on the status of implementing PUC audit recommendations, that it was encountering problems with the reliability and validity of the data and reports generated from its Outage Management System. In response to LB&FC questions about the 1999 and 2000 reliability data Allegheny Power submitted to the PUC, however, the company indicated that issues and concerns had arisen not only with its historic reliability data, but also with the reliability data generated from its Outage Management System since 1999. The company indicated that its Outage Management System vendor had not prepared it to anticipate some of the problems it had encountered.

In March 2002, Allegheny Power shared with the LB&FC, and the director of the Bureau of CEEP, the company's action plan to address the issues it had identified with the Outage Management System. Such issues included inconsistent and

[9]Company data reported to the PUC in annual reliability report submissions indicate that the company's Customer Average Interruption Duration Index for 2000 was 206 minutes, which is lower than the index for 1999, but well above the company's reported historic performance in 1994, 1995, 1996, and 1997. The company's reported performance in 1998 was one minute better than its 2000 reported performance.

inaccurate reliability data for calendar year 2001. The plan includes target dates for completion of action plan steps through the second half of 2002.

Based on the information provided to the LB&FC, it is unclear how the company is implementing the PUC's May 2000 audit recommendation that the company analyze service interruption and reliability data in a timely way. As the PUC report notes:

> In order to meet the [PUC's] reliability performance standard a [company] must effectively inspect, maintain and operate its distribution system. This includes analyzing service reliability performance, and where necessary, effectively implementing corrective measures to improve reliability.

Absent timely analysis of reliability performance data, the company "may be focusing on implementing corrective measures to historical problems that are no longer the primary causes of poor service reliability."

Allegheny Power indicates that it uses the reliability information to identify and target the company's worst performing circuits for improvements. Allegheny views the problems with the reliability of the data from its Outage Management System to be uniform throughout all of its operating divisions and not unique to its Pennsylvania operations. Therefore, the problems would affect all circuits in the system in the same way and not distort the decisions managers make based on the available data.

Linemen and Servicemen Staffing Levels. The PUC audit found that in 1999 overtime for lineworkers generally exceeded 10 percent of regular hours, and in some areas was near or exceeded 20 percent of regular hours. The audit noted the company had budgeted 10 percent of regular hours for overtime; however, in 1999 company overtime was 15 percent of regular hours.

Given the variance between the company's budgeted overtime and actual overtime, the PUC audit noted the company could have saved about $500,000 by hiring 16 additional linemen. In addition to the efficiencies associated with the hiring of additional linemen, the audit noted that not all of the company linemen and servicemen were qualified to perform emergency service restoration and, of those that were, 7.9 percent would be eligible for retirement within five years.

The PUC audit recommended the company identify the primary reasons for excessive overtime levels among lineworkers and ensure that staffing levels of lineworkers do not negatively impact customer service and service reliability. The company did not accept the PUC's audit recommendation, but indicated it would analyze overtime at each Pennsylvania service center on a monthly basis in an effort to reduce overtime hours without negatively affecting customer service and reliability.

In June 2001, the company reported it continued to monitor and review overtime levels and found that such levels had dropped from roughly 15 percent in calendar years 1999 and 2000 to 13 percent as of June 2001. The company reported that, in addition to opening a new service center in 2001, it was considering staffing all Pennsylvania service centers with an afternoon shift serviceman for extended coverage and adding a flex lineman position at selected service centers that would provide coverage Monday through Saturday for all service centers.

The company further indicated the Person on Duty would be notified in several situations to determine if on-site supervision of restoration was required. The Person on Duty would be notified routinely when more than five linemen are called out on a job, when the cause of the outage is a downed pole due to an accident, a broken pole, a complete circuit lock out, bad underground, or a pole or transformer fire, and when hazardous conditions exist. The company noted this procedure would also allow management to evaluate the situation to determine if the work needs to be completed on an overtime basis or if it could be scheduled during normal working hours, thus reducing overtime.

Pole Replacement. The PUC audit noted that the company had a pole inspection and replacement program. When pole inspection indicates that a pole has reached the end of its useful life and cannot be reinforced, it must be replaced. A pole in need of replacement and categorized by the company as a "reject pole" requires replacement within a couple of months to a year. A pole categorized as a "danger pole," however, is considered hazardous and must be secured within five days of discovery. Inspectors tag "danger poles" so that linemen and other utility companies using the poles know that they are hazards and should not be climbed. Inspectors also inform the company of any such poles so the company can take immediate action.

The PUC audit reported that the company had in place a process for tracking pole replacement that made it difficult to track replacement of individual poles. As a result, the company could inadvertently lose track of a "danger pole" that required immediate attention.

During the course of the audit, the company advised the PUC auditors it was improving its tracking processes, revising its Work Management System to support the Pole Replacement Program, and had trained some of its staff to use the new tracking mechanisms. The PUC auditors, however, found that all personnel who use the tracking system were not able to provide consistent descriptions of the pole replacement tracking process and the purpose of various features of the tracking system.

The PUC audit recommended that all personnel who use the Work Management System for tracking the Pole Replacement Program be trained. The company accepted the PUC audit recommendation. It provided information about the revised tracking system to personnel using the system in February 2000, conducted personnel training in February and March 2000, and indicated it would continue to monitor the Pole Replacement Program. In June 2001, the company reported that a review of the Pole Replacement Program had become part of the company's Quality Assurance Inspections.

GPU. The PUC released its most recent management and operations audit of GPU in December 1998. The audit included several relevant findings concerning the status of the company's transmission and distribution systems reliability.

Absence of Reliability Performance Goals. The PUC audit reported the company had not developed performance goals for service interruption and power quality reliability indices. The company reported it had not developed such goals because of the unpredictability of storms on reliability indices and the manual and semi-manual reporting systems that were in place within the company. The company, moreover, indicated it was awaiting the PUC's standards before developing any company service interruption goals.

The PUC audit recommended that the company develop annual service interruption and power quality reliability goals for its system and operating areas. In January 1999, GPU indicated that it accepted the PUC's recommendation in part. It indicated it would establish reliability goals for its operating areas at two standard deviations above the operating area's average historic performance in 1994 through 1998. The company rejected the parts of the PUC recommendation calling for the establishment of system reliability goals to measure power quality. The company indicated it did not collect and maintain the historic data necessary to establish a standard for power quality and that it would be costly to implement and administer a program to collect and report extensive power quality data.

In January 2001, the company reported it was maintaining reliability by targeting distribution circuits where the top 25 percent of the customer minutes of interruption occurred. It reported having completed a worst circuit analysis for 1998 interruptions in August of 1999, and for 1999 interruptions in February 2000.

Transmission Reliability. The PUC audit found that GPU had participated in a study comparing reliability of 21 companies' transmission systems, and the results of the study showed that GPU performed far below the companies' average for subtransmission (34.5-70kV) voltage class. The PUC audit recommended the company develop an action plan to address areas for potential improvements to the parts of its transmission system identified by the study.

The company accepted the PUC's recommendation, indicating it would identify ways to obtain performance data on its transmission circuits similar to that used in the study. In March 2000, it reported it had obtained the services of a contractor and was using data on its transmission system availability to establish priorities for the company's transmission inspection program. It also had drafted for implementation a transmission circuit reliability program to address the performance of the worst performing transmission circuits.

Transmission and Distribution Safety Goals. The PUC audit found GPU had the company safety goals, but they were not specific to the transmission and distribution organization process. The company used the federal Occupational, Safety & Health Administration's (OSHA) safety goal rate based on number of OSHA recordable cases (i.e., cases of restricted work day cases, lost work day cases, and fatalities) per 100 employees. The OSHA safety goal rate, however, included customer services, corporate services, support resources, accounting, and material management as well as transmission and distribution processes. Between 1995 and 1997, GPU had not met its OSHA safety goal rate, and its actual performance varied 40 to 50 percent from the company target.

The PUC audit recommended the company develop specific safety goals exclusive to the transmission and distribution process to establish more realistic targets and allow management to better identify where improvements were needed. In January 1999, the company accepted the PUC recommendation indicating it would develop safety goals based on the number of times transmission and distribution employees actually injure themselves and the costs associated with such injuries rather than rely on OSHA incident rates. With this change, the company indicated its transmission and distribution organization would be able to better determine the rate and seriousness of injuries and develop preventive measures.

In March 2000, the company reported that in 1999 it made a major organizational shift to process-based operations and had decided, therefore, to continue measuring safety performance for the transmission and distribution process in the same way to maintain consistency within the corporation. The company's goal for 2000 was to have an OSHA incident rate of less than 5 and to reduce worker's compensation costs by 10 percent. The company also reported on a series of programs to help achieve its goals.

Subsequently, the company reported to the PUC that it did not meet its OSHA incident rate safety goal in 1999, 2000, and 2001, though its performance improved in 2001 over that of the previous year. The company also reported its worker's compensation costs had increased due to more serious accidents and claims in 2000.

In 2002, the company reported to the PUC that it had once again reorganized in 2001 from a process-based organization to a decentralized region-based organization. The company reported it was developing OSHA incident rate safety goals for each of its regional operating organizations.

Vegetation Management. The PUC audit found the company did not have specific annual goals and cost indicators for its vegetation management program. The report noted the company had increased the distribution miles trimmed by 211 percent from 1995 to 1997 and had reduced its cost per mile by 46 percent. At the same time, the customer minutes lost due to preventable tree-related outages increased 34 percent, and the average customer interruption duration increased 23 percent. The audit noted the lack of expected performance levels may be contributing to the negative tree-related service interruption trend.

The PUC audit recommended the company develop cost and performance indicators for its vegetation management program and link the indicators to specific annual goals. The company agreed with the recommendation in January 1999, indicating it planned to establish goals and monitor cost and performance indicators, including frequency of '"preventable" tree-related interruptions, distribution miles maintained, and cost per mile of planned maintenance.

The company set a goal of performing 6,400 miles of distribution line inspection and maintenance for vegetation in 1999 and to maintain a four-year vegetation maintenance cycle. Table 10 shows the progress GPU reported to the PUC in meeting its goal to maintain a four-year vegetation maintenance cycle.

Table 10

GPU Targeted and Actual Miles of Distribution Line Inspection and Maintenance for Vegetation

Year	Goal for Miles of Distribution Line Inspection and Maintenance for Vegetation	Actual for Miles of Distribution Line Inspection and Maintenance for Vegetation
1999	6,400	6,840
2000	6,400	6,050
2001	6,550 (reduced to 5,950 due to budget modifications)	5,800
2002	7,336 to maintain a four-year maintenance cycle	Not Available

Source: Developed by LB&FC staff from information GPU reported to the PUC in January 2002.

The company also set a goal of annually reducing the frequency of distribution tree-related interruptions by 10 percent from the prior three-year average. However, GPU reported to the PUC that its three-year average of tree-related interruptions rose from 1,540 interruptions for 1998-2000 to 1,735 interruptions for 1999-2001. The frequency of tree-related interruptions that are reported as non-preventable increased from a three-year average of 640 interruptions in 1998-2000 to 751 interruptions on average for 1999-2001.[10]

"Spotter" Program. The company's own internal audit and the PUC audit found the company did not have a formal "spotter" training program for its Pennsylvania operating companies. Typically, trained "spotters" function as advanced observers identifying the source of service interruptions while line repair trucks are on route. The audit noted that timely and accurate spotting enables linemen to be quickly dispatched to safeguard an area and make repairs thereby minimizing the danger to the public and/or public service emergency workers.

The PUC audit recommended the company develop a "spotter" training program. In January 1999, the company accepted the recommendation. It indicated it would implement the recommendations by training meter readers to serve as spotters.

The company subsequently reported it had trained meter readers to serve as spotters, but later reported that it was revising its program and the functions performed by its trained spotters. In January 2002, GPU reported that in anticipation of its merger with FirstEnergy, new dispatching processes had been implemented and the role of the "spotter" had been expanded to include responding to the site of the outage where a probable hazard exists, keeping the public clear of any hazards, identifying hazard and damage conditions, reporting back to hazard dispatch personnel, and standing by until the hazard is eliminated.

Safety Manual. The PUC audit reported that GPU did not have a consolidated transmission and distribution safety manual for its Pennsylvania operations. Rather, separate safety manuals existed for the former Met-Ed and Penelec that were supplemented by "position statements" intended to clarify or interpret existing safety rules.

The PUC audit noted Penelec's safety manual was more extensive and detailed than Med-Ed's and that the manuals differ with respect to procedures for identical tasks. The position statements intended to provide clarification or interpretation of safety rules, moreover, did not reference specific sections of the manuals.

The PUC audit recommended the company consolidate and standardize its transmission and distribution safety manuals to reflect GPU organizational changes to a centralized, process-based company. In January 1999, GPU accepted

[10]GPU reported the tree-related reliability data was based on primary distribution voltages only and it excluded major storm events. Data for calendar year 2001 include projected data for December 2001.

the recommendation and indicated it would require two years to implement the recommendation because safety practices are items within negotiated labor contracts with individual bargaining units. The company reported, however, that it was taking steps to standardize safety rules in 1999. Such steps included the development of consistent rules for switching and tagging, enclosed space entry, and grounding. The company also created a management team to consolidate safety rules and practices. By January 2001, the team had completed most of its work. In January 2002, however, the company reported to the PUC that the completion of the recommendation was on hold pending its merger with FirstEnergy.

Outage Management Process. The PUC audit reported the company's internal audit department had investigated the company's outage/storm management process to determine the adequacy and effectiveness of company controls for the management of major storms. The company's internal auditors had identified 14 findings and opportunities for improvement. The PUC audit recommended the company implement such improvements in a timely manner.

The PUC audit noted the company was working to implement some of the improvements during the course of the audit. Specifically, through its reorganization the company was addressing the problem of some regions operating in a "territorial manner" when other regions required storm assistance. Since storm restoration guidelines differed across regions, the company was developing common storm restoration guidelines.

The company reported it was placing its emergency operating guidelines online to ensure that all manual holders had current guidelines and updated organizational charts that clearly defined key responsibilities during a storm. It also reported it had developed and implemented the use of a common form for outage assistance requests and damage analysis, and it had started issuing credit cards to project leaders to address the problems associated with their lack of cash funds. Moreover, the company indicated it was taking steps to implement storm drills on a regular basis.

In addition to the activities it reported to the PUC in 1998 to improve its service reliability, GPU is specifically involved in certain activities to improve the service reliability of its transmission system. GPU's restructuring settlement agreement provides for a joint planning process involving representatives of the company, the Pennsylvania Rural Electric Association (PREA), and a consumer representative. The purpose of the process is to develop an annual plan for allocation of GPU expenditures for projects devoted to transmission and distribution circuits that impact the service of the PREA, which receives transmission services primarily from GPU.

The restructuring settlement agreement describes how the process will work from 1999 through 2009 and notes specific dollar amounts that GPU agreed to allocate for reliability improvements for facilities serving PREA delivery points. It also included specific performance reliability standards for GPU's transmission system at points where it impacts PREA service. As part of the agreement, the PREA withdrew its reliability complaint against GPU that was pending before the Federal Energy Regulatory Commission.

The GPU merger settlement agreement also provides for Met-Ed and Penelec to form a reliability committee made up of representatives of the companies, the Office of Consumer Advocate, industrial customers, and PA PUC staff. The committee is to meet on a quarterly basis starting within six months of GPU's merger with FirstEnergy. The purpose of the committee as described in the agreement is to:

- monitor the companies' reliability improvement program;
- discuss reliability and service related issues;
- develop reliability and other service related criteria that provide for improved service to customers; and
- attempt to resolve any disputes concerning the reliability performance before such disputes are taken to the PA PUC.

As of May 2002, the PUC was in the process of conducting a Management Efficiency Investigation for GPU. The audit is a follow-up to the PUC's December 1998 Management and Operations Audit.

Duquesne. In March 1998, the PUC issued a Diagnostic Management Audit of the company prepared by a consultant on behalf of the PUC. Prior to this in 1995, the PUC Bureau of Audits had conducted a management and efficiency investigation into the company's handling of power outages in July 1995. The PUC investigation in part found that transformer-related interruptions were the primary cause of the extended and/or repeated outages in July 1995; the company's distribution operation center did not have an automated trouble analysis capacity; staffing levels for customer field personnel had decreased; and the emergency service restoration plan needed to be improved. In addition, the PUC investigators reported the company was attempting to improve the effectiveness of its preventative and predictive maintenance activities.

The March 1998 PUC audit confirmed that the company had initiated steps to improve its service reliability. The PUC's consultant reported that the company reliability performance had declined during the period 1993 through 1996, and that:

> DCL acknowledges that in the late 1980s and early 1990s, it banked against the built-in safety margin of its system, and did not spend sufficient resources to maintain and upgrade the system, and thereby maintain its reliability ratings.

The consultant found the company had "recognized its reliability problems and has taken significant efforts to improve system reliability." The company recognized that it had reliability problems in part as a result of the 1995 capacity and storm-related outages and the company's recognition that it had probably cut operational, maintenance, and capital budgets too severely. After 1995, the company established a reliability organization whose sole purpose was to evaluate and improve system reliability and capacity. In early 1996, the company established its System Assessment Plan, a multi-year plan that identified system, circuit, and substation upgrades needed to address the most critical factors affecting system reliability and its ability to meet future capacity.

The PUC consultant found that the company had:

- Demonstrated a commitment to achieving its System Assessment Plan, and as of 1997 the results appeared promising.
- Spent significant effort to identify and correct complaints regarding low voltage and power quality.
- Initiated plans to implement reliability centered maintenance (RCM)[11] practices, which, if implemented correctly, can have a positive impact on reliability.
- Established an innovative vegetation management program, involving doubling of tree trimming expenditures from 1995 through 2000, improving its contracting, and using circuit-by-circuit analysis to target those circuits which experience the highest interruption incident rates.

The PUC consultant recommended the company continue such efforts.

In 2001, Duquesne reported to its customers that its vegetation management program had resulted in a 56 percent reduction in tree-related outages since 1997 and that it was investing in system improvements such as expanding the number of remote switching devices used to restore power automatically and constructing new substations.

[11]RCM is a process for planning and prioritizing maintenance resource allocations. RCM focuses on asset management. In the context of transmission and distribution systems, this involves maintenance of a complete inventory of all equipment assets with their maintenance and operating history, and the ability to correlate such history to the asset inventory. RCM also focuses on duty-based maintenance cycles. The asset management approach helps identify equipment failure trends, and helps establish preventive maintenance schedules based on duty cycles, rather than time. For example, relays would be maintained based on the number of open/closed cycles they experience, rather than on a strict period basis. RCM also involves use of a number of diagnostic tools to identify equipment problems before they occur. Such tools involve infrared monitoring, vibration testing, and oil analysis. RCM requires significant effort with respect to asset management, data collection, and analysis. Without careful planning and maintaining of such efforts, the potential benefits of RCM will not be realized.

The company also reported it was focusing on reducing time required to correct power outages caused by severe weather. It had developed a new storm response strategy to position employees and equipment closer to the communities they serve by expanding the number of neighborhood maintenance centers located throughout the service territory. In its 2000 reliability report to the PUC it noted it had deployed line crews and troubleshooters at nine strategic locations, up from six. Prior to the establishment of the three new neighborhood maintenance centers, field personnel had to drive up to 50 minutes to respond to these areas.

The company also noted in the annual reliability reports it submits to the Commission that its vice-president in charge of system reliability meets regularly with the company head to discuss reliability issues. After having completed implementation of its 1995 System Assessment Plan, the company initiated ongoing preventative, corrective, and predictive maintenance activities to reduce the potential for future service interruptions.

The company further reported it had contracted with the Electric Power Research Institute (EPRI) to assess the reliability of its downtown underground network. The assessment includes 78 recommendations. The company was evaluating each recommendation and had already included funding to implement some of the recommendations in its 2001 capital and maintenance budgets.

In February 2002, the PUC was in the process of developing a draft report based on its Management Efficiency Investigation of Duquesne. The PUC was completing the investigation in follow-up to its March 1998 Management and Operations Audit of the company.

Penn Power. In May 1998, the PUC released its most recent focused management and efficiency audit for Penn Power. The audit noted the company had established reliability performance targets. The company relied on a Circuit Reliability Index (CRI) it had developed to monitor reliability performance. CRI is calculated based on a rolling 12-month analysis of circuit performance, which is measured by the Momentary Average Interruption Frequency Index (MAIFI), Customer Average Interruption Duration Index (CAIDI), and System Average Interruption Frequency Index (SAIFI). The company's goal is to have 80 percent or more of its circuits with CRIs of 130 or less. The audit reported that 80 percent or more of Penn Power's CRIs in 1994 and 1995 were below 130, but increased to above 130 in 1996.

Service Outage Report Guidelines. Penn Power is owned by an Ohio utility, and the PUC audit found that the company's emergency response plan did not include the service outage information that Pennsylvania's regulations require companies to report when 2,500 or 5 percent of customers, whichever is less, have service interrupted for six or more projected consecutive hours (see Appendix G). Penn

Power's emergency response plan only referenced Ohio's service outage reporting requirements.

The PUC audit recommended the company include specific references to Pennsylvania's service outage reporting requirements in the company's Emergency Storm Restoration Plan. The company accepted the PUC audit recommendation and in 1998 revised its Emergency Storm Restoration Plan to include Pennsylvania's reporting requirements.

Automated System Reports. The PUC audit found problems with company generation of certain management reports. Specifically, reports summarizing substation equipment problems were not being generated by the company's automated systems. Substation supervisors had to manually develop such reports, and this was not done very often.

Penn Power had developed a program to monitor the productivity of its tree-trimming contractors and gathered data (i.e., contractor's time to complete work, location of work, crew members, equipment hours, number of trees removed, area of brush cleared, amount of chemical applied, miles of line cleared, etc.) to monitor such productivity. It had not, however, programmed its system to produce summary reports on company tree-trimming expenses. Such reports had to be generated by the company's forester.

In addition, the PUC audit found the company reports used to track work backlog did not contain adequate information to keep management informed of the status of work. The reports lacked information on the:

- work's start date and estimated completion date;
- percentage of work actually completed;
- estimated amount of time and expenditures required to complete the work;
- reason for the delay or backlog; and
- priority of delayed or backlogged work based on dollars, impact upon the system, impact upon other projects, safety, etc.

The report, however, noted the company was in the process of starting to implement a Customer Request Work Scheduling (CREWS) system.

The PUC audit recommended the company expedite programming to provide reports summarizing substation equipment trouble and tree trimming expenses. It also recommended that the company ensure the new CREWS system include a work order backlog report.

The company accepted the PUC audit's recommendations. In 1998, the company reported it had developed an Apparatus Trouble Report Summary. It also reported a new Vegetation Management System would be in place by the end of 1998, and that the CREWS system that would be in place in 1999 would accomplish the PUC's recommendation concerning tracking of work backlog. In June 2001, the company reported that after certain delays it had implemented the CREWS system.

Infrared Thermograph Inspections. The PUC audit reported:

> The [company's] preventive maintenance programs for distribution circuits consist of maintenance of line reclosers and line regulators. Visual inspections of line reclosers are done quarterly, with counter readings analyzed to determine circuit reliability. A complete overhaul of line reclosers is done on an as needed basis. Visual inspections of line regulators are done annually, with a complete overhaul done on an as needed basis.

The PUC audit, however, found that the company was not performing predictive maintenance on its distribution circuits. This had resulted in the number of equipment failures, line failures, and failures due to overload increasing. Outages due to overload increased 59 percent from 1993 through 1996. The audit notes that "in 1996, transformer trips or failures accounted for approximately 63 percent of the overload outages, and blown fuses accounted for approximately 32 percent of the overload outages." The company attributed this increase to better reporting by its staff in properly categorizing various types of outages.

The PUC audit recommended the company develop a program to periodically conduct infrared thermograph inspections on its distribution line circuits to scan distribution line circuit equipment and locate areas of poor performance. The PUC audit noted such inspections would allow the company to locate problems quickly without interrupting services, reduce costly unscheduled interruptions and power outages, and extend equipment life by locating problem components prior to catastrophic failure.

The company rejected the PUC's recommendation. It noted that it used infrared thermography to routinely inspect connections in and around distribution substations and to inspect lines that are suspect in the judgment of company line supervision and personnel. The company, however, thought it would be logically and financially impractical to use such inspections for all of its distribution system connections. The company indicated it would continue to use its engineering analysis employing its CRI index with actual performance data to assess its distribution circuits and justify and prioritize corrective actions for circuits not meeting the company reliability performance goals.

As of February 2002, the PUC was in the process of completing a Management and Efficiency Investigation of Penn Power. The investigation was in follow-up to the PUC's May 1998 Management and Operations Audit of the company.

UGI. The PUC made available to the public a Stratified Management and Operations Audit of UGI Utilities in February 1997. The audit examined reliability data for periods prior to the enactment of electric restructuring legislation in Pennsylvania. It did not include any negative findings related to transmission and distribution systems reliability.

E. *Reliability of Transmission Systems Is Primarily Assured Through Voluntary Organizations*

Historically, the North American electric system has been the most reliable system in the world. This is the result, in large part, of the North American Electric Reliability Council (NERC), which was formed by electric utilities in 1968, in response to the November 9, 1965, northeast blackout. The major causes of the blackout were the loading of transmission lines beyond safety limits and inadequate communications among utilities.[1] Since then, NERC has operated as a voluntary organization—dependent on reciprocity, peer pressure, and the mutual self-interest of all those involved. Under the present system, compliance with NERC standards is "mandatory" for NERC members, but it is not enforceable.

North American Electric Reliability Council

NERC is a not-for-profit corporation. Its members consist of ten Regional Reliability Councils:

- Mid-Atlantic Area Council (MAAC),
- East Central Area Reliability Coordination Agreement (ECAR),
- Electric Reliability Council of Texas (ERCOT),
- Florida Reliability Coordinating Council (FRCC),
- Mid-America Interconnected Network, Inc. (MAIN),
- Mid-Continent Area Power Pool (MAPP),
- Northeast Power Coordinating Council (NPCC),
- Southeastern Electric Reliability Council (SERC),
- Southwest Power Pool (SPP), and
- Western Systems Coordinating Council (WSCC).

The Regional Council members come from all segments of the electric industry: investor-owned utilities; federal power agencies; rural electric cooperatives; state, municipal and provincial utilities; independent power producers; power marketers; and end-use customers. The members account for virtually all the electricity supplied in the United States, Canada, and a portion of Mexico.

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[1]Electric systems have two important characteristics. First, they require a continuous and virtually instantaneous balancing of generation and load. This requires metering, computing, telecommunications, and control equipment to monitor loads, generation, and the transmission system and to adjust generation to match load. Second, the transmission system is primarily passive; there are few controls to regulate the flows on individual lines. As a result of these characteristics every grid event can affect all other activities on the grid. Therefore, the action of all bulk-power participants must be coordinated. Cascading effects of a system fault must be avoided. Failure of a single system element can, if not properly managed, cause the subsequent rapid failure of many additional elements, disrupting the grid over an enormous area. Preparation for the next contingency, or unexpected event dominates the design and operation of bulk-power systems. Actions are often required instantaneously, requiring computing, communications, and automatic controls designed based on sound modeling and planning.

NERC Reliability Principles

Member councils of NERC develop organizational standards to ensure safe and reliable transmission systems based on NERC "Reliability Principles." These principles define the foundation of reliability for North American bulk electric systems. As a result, member councils may have different organizational standards. As shown in Exhibit 13, NERC has seven reliability principles.

Exhibit 13

NERC Reliability Principles

Reliability Principle 1: Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and prescribed abnormal conditions.

Reliability Principle 2: The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

Reliability Principle 3: Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.

Reliability Principle 4: Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained, and implemented.

Reliability Principle 5: Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk electric systems.

Reliability Principle 6: Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified, and have the responsibility and authority to implement actions.

Reliability Principle 7: The security of the interconnected bulk electric systems shall be assessed, monitored, and maintained on a wide-area basis.

Source: Developed by LB&FC staff.

Within the Reliability Regions to implement NERC reliability principles, utilities have formed "control areas." A control area is the basic operating unit of the electric power industry. A control area can consist of either a single utility or two or more utilities tied together by contractual arrangements. Each control area manages its generation to meet electricity demand and fulfill exchange obligations. Control areas also help the power interconnections[2] of which they are a part to regulate and stabilize the frequency of electric current. Control areas are responsible for matching electric supply with demand hour-to-hour and minute-to-minute. The coordination of the separate utility activities into an integrated power supply

[2]Within the United Sates, all electric utilities operate within one of three interconnections.

system is the responsibility of the control area. Some "control areas" have been designated as NERC security coordinators to assure that the transmission system is not overloaded.

Because transmission systems operate on an interstate basis, the Federal Energy Regulatory Commission (FERC) is responsible for establishing rates for the transmission services. To assure that wholesale energy markets operate on an open and competitive basis, and that the companies that own transmission facilities and also generate power do not exercise undue market influence, the FERC in the 1990s required the development of independent system operators (ISOs). ISOs are non-profit entities that control, but do not own, the transmission facilities. While all ISOs do not operate in the same way, the FERC requires them to ensure short-term transmission reliability through compliance with the standard of the NERC and its Regional Reliability Councils. Most ISOs, therefore, serve as NERC security coordinators, providing security assessments and coordinating emergency operations for their transmission grid control area(s).

PUC Transmission Reliability Requirements

Like FERC, the PUC in large part assures the reliability of transmission systems in Pennsylvania by requiring that electric distribution companies operating in the Commonwealth operate such facilities in conformity with the operating policies, criteria, requirements, and standards of NERC and the appropriate Regional Reliability Councils (or their successor organizations).[3]

The PUC also requires electric distribution companies to annually submit a report on the transmission system's available transfer capability, total transfer capability, and the use, in general, of the transmission system. The report must include an assessment of the past performance of the transmission system and an appraisal of future transmission system performance. Companies are not required to individually submit such reports. To comply with the PUC's requirements they may submit a joint report prepared by an ISO or other appropriate transmission system operator.

While not explicitly stated in the PUC's electric service reliability regulations, electric distribution companies must also include in their annual reliability performance data sustained service interruptions on their distribution systems that are caused by problems on the transmission system. The only exception to this is interruptions that qualify as major events. (See page 42 for information on such exceptions.) Transmission related outages that result in sustained service interruptions on company distribution systems are, therefore, included in the company performance reliability data reported on page 60.

[3]52 Pa. Code §57.193(c).

In addition, companies report transmission related service outages to the PUC as required by separate service outage regulations. Since 1992, four of the seven major companies (PPL, GPU, Allegheny Power, and Penn Power) have reported extended service outages due to transmission related problems. Most (six of seven) of these extended outages have occurred since 1998.[4]

Pennsylvania EDCs Regional Reliability Council Participation

Most of Pennsylvania's major investor-owned EDCs are members of the Mid-Atlantic Area Council (MAAC), including PECO Energy, PPL, GPU operating companies (Metropolitan Edison and Penelec), and UGI. Duquesne and Penn Power are participants in the East Central Area Reliability Coordination Agreement (ECAR).

MAAC is administered by the PJM Interconnection, L.L.C. PJM was the first power pool in the United States. It centralized the operation of the generation and transmission resources of participating utilities in a six-state area when it was formed in the late 1920s. In its Regional Reliability Council role, PJM is responsible for regional transmission planning and it functions as the NERC security coordinator for the region. In the late 1990s, FERC designated PJM to serve as the ISO for the region.

A new MAAC agreement, which went into effect on January 1, 2001, provided that all members of the PJM Interconnection, L.L.C., become MAAC members. Under the MAAC Agreement, PJM members are obligated to comply with MAAC and NERC Operating Policies and Planning Standards.

The MAAC region is geographically the same as the PJM Interconnection control area. It encompasses nearly 50,000 square miles and through its members provides electricity to more than 23 million people--about 9 percent of the nation's population. MAAC members, through the PJM Independent System Operator, serve customers in Pennsylvania, New Jersey, Maryland, Delaware, Virginia, and the District of Columbia.

On April 1, 2002, PJM expanded its geographical boundaries (and market) with the creation of PJM West through an agreement with Allegheny Power. The agreement provides for Allegheny to participate in the ECAR and adhere to ECAR reliability standards. At the same time, Allegheny will integrate its transmission facilities into a regional transmission organization to form PJM West. As a result, PJM will also serve large portions of West Virginia and parts of Ohio.

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[4]It is important to note that the company's transmission network itself might not be the cause of the outage. Such problems can be due to other transmission system operators.

Although the NERC model has had a history of success, the growth of competition and the structural changes taking place in the electric power industry have significantly altered the incentives and responsibilities of market participants to the point that a system of voluntary compliance is no longer adequate. In response to industry changes, NERC is in the process of transforming itself into the North American Electric Reliability Organization, and its principal mission will be to develop, implement, and enforce standards for a reliable North American bulk electric system. NERC is working with its members to incorporate an enforcement mechanism through the development of contracts between NERC's regional councils and their members. There are also various federal legislative proposals that are being advanced to ensure that NERC and its regions have clear statutory authority to enforce compliance with reliability standards among all market participants.

IV. Appendices

APPENDIX A

Selected Federal Statutes and Orders Related to Electric Utility Restructuring

Public Utility Holding Company Act (PUHCA) of 1935 (Public Law 74-333)

Purpose: To break up large trusts that controlled the nation's electric and gas distribution networks.

Securities and Exchange Commission Requirements (SEC): Authorized the SEC to break up the trusts, limit utilities to the jurisdiction of a single state, confine activities to the business of operating a utility and its related affairs and regulate the reorganized industry to prevent the return of trusts.

Federal Power Act (Title II of PUHCA): Empowered the Federal Power Commission to regulate transmission of electric energy in interstate commerce and the sale of electric energy at wholesale in interstate commerce by public utilities.

Public Utility Regulatory Policies Act (PURPA) of 1978 (Public Law 95-617)

Purpose: To encourage the efficient use of fossil fuels in electric power production through cogenerators and the use of renewable resources through small power producers.

Non Utilities: Both cogenerators and small power producers could have no more than 50 percent of their equity held by an electric utility; requirements for classification as cogenerator or small power producer defined.

Qualifying Facilities (QF): Required electric utilities to interconnect with and purchase power from any facility meeting the criteria for a QF; required utility to pay for that power at the utility's own incremental or avoided cost of production; exempted from certain regulations under Federal Power Act and PUHCA.

Energy Policy Act of 1992 (Public Law 102-486)

Purpose: To encourage competition in energy markets.

Requirements: Created exempt wholesale generators (EWG), a new category of power producers exempted from the requirements of PUHCA; directs FERC to open up the national electricity transmission system to wholesale suppliers on a case-by-case basis.

Appendix A (Continued)

FERC Orders:

888 (issued 1996): Provided open access to the bulk power transmission grid to all electricity suppliers including power marketers, electric utilities and non-utilities by requiring utilities owning bulk power transmission facilities to treat any of their own new wholesale sales and purchases of energy over their own transmission facilities under the same transmission tariffs they apply to others (known as comparable service); authorizes recovery of legitimate and verifiable stranded costs.[1]

889 (issued 1996): Requires utilities to establish electronic systems to share information about available transmission capacity (known as the Open Access Same-Time Information System).

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[1]The U.S. Supreme Court recently upheld FERC's authority over interstate transmission for any retail sales, including unbundled sales, in New York et al. v. FERC et al., 535 U.S. ___ (2002).

Source: LB&FC staff review of Public Laws 74-333, 95-617, 102-486, and FERC Orders 888 and 889.

APPENDIX B

Selected Provisions of Pennsylvania's Electricity Generation Customer Choice and Competition Act

Purpose: To establish standards and procedures to create direct access by retail customers to the competitive market for the generation of electricity while maintaining the safety and reliability of the electric system for all parties. (66 Pa. C.S.A. §2802)

Standards for Restructuring: Requires the unbundling of electric utility services, tariffs and customer bills to separate the charges for generation, transmission and distribution; establishes rate caps; requires each utility to submit an initial plan that sets forth how it shall meet its universal service and energy conservation obligations; directs the PUC to issue regulations to permit electric distribution companies to recover certain state tax liability. (66 Pa. C.S.A. §2804)

Implementation and Pilot Programs: Created pilot programs requiring phased implementation through January 1, 2001, when all customers of electric distribution companies have opportunity for direct access; restructuring plans required to be filed by September 30, 1997, to implement direct access to a competitive market for the generation of electricity; restructuring plans to include: (1) unbundled rates or prices for generation, jurisdictional transmission, distribution, and other services; (2) a proposed competitive transmission charge; (3) a proposed universal service and energy conservation cost-recovery mechanism; (4) procedures for ensuring direct access to all licensed electric generation suppliers; (5) a discussion of the impacts of the proposed plan on the utility's employees; and (6) revised tariffs and rate schedules to implement; review of the restructuring plans by the PUC; authorizes the PUC to approve flexible pricing and flexible rates and performance-based rates. (66 Pa. C.S.A. §2806)

Electric Distribution Companies (EDC): Responsible for billing customers for all electric services regardless of the identify of the provider of those services, subject to the right of the customer to receive separate bills; requires the PUC to establish regulations to ensure an EDC does not change a customer's electricity supplier without direct oral confirmation from the customer and require EDCs, electric suppliers, marketers, aggregators and brokers to provide customer information to enable customers to make informed choices regarding the purchase of all electricity, services offered by that provider. (66 Pa. C.S.A. §2807)

Appendix B (Continued)

Competitive Transition Charge: Customers pay a competitive transition charge to the EDC in whose certificated territory the customer is located for a period not to exceed nine years; the charge is determined by the PUC taking into consideration items enumerated in the act and review it annually; the recovery plan shall be included as part of the restructuring plan. (66 Pa. C.S.A. §2808)

PUC Regulation of Electric Generation Suppliers: Required to be licensed by the PUC and meet financial responsibility requirements; PUC to impose requirements to ensure present quality of service provided by electric utilities does not deteriorate, including that adequate reserve margins of electric supply are maintained and standards and billing practices for residential service are maintained; PUC required to establish standards to ensure all retail customer classes may choose to purchase electricity through a broker and marketer or aggregator before licensing those categories. (66 Pa. C.S.A. §2809)

Revenue-Neutral Reconciliation: Revenue replacement at a rate intended by the General Assembly to recoup losses that may result from the restructuring of the electric industry and the transition thereto through tax rates; EDCs are required to report their annual gross receipts.

Market Power Remediation: The PUC monitors the market for the supply and distribution of electricity to retail customers and takes steps to prevent anti-competitive or discriminatory conduct and the unlawful exercise of market power; activities include investigations, referrals of investigation results to the Attorney General, U.S. Department of Justice, the Securities and Exchange Commission, or the Federal Regulatory Commission, or intervention by the PUC; the PUC approves proposed mergers, consolidations, acquisitions or dispositions. (66 Pa. C.S.A. §2811)

Source: LB&FC staff review of Act 1996-138, 66 Pa. C.S.A. §§2801-2812.

APPENDIX C

Selected State Reliability Reporting Requirements

California[1]

- Requires annual reporting of SAIFI, SAIDI, MAIFI reliability indices for a utility system, and monthly or quarterly data for smaller portions of the system (region or circuit) upon request.
- Excluded in the outages used to calculate reliability indices are planned outages (i.e. outages necessary to connect new customers or perform maintenance activities safely where customer are notified in advance) and major events.
- Major events that are excluded from the reliability indices calculations must meet either of the two following criteria: (a) the event is caused by earthquake, fire, or storm of sufficient intensity to give rise to a state of emergency declared by the government, or (b) any other disaster not in (a) that affects more than 15 percent of the system facilities or 10 percent of the utility's customers, whichever is less for each event.
- Annual reports must include information about any group of customers commonly served by a circuit that experience more than one 5 (or more) minute outage per month on a rolling annual average basis.
- Annual reports must identify the ten largest outage events and indicate whether any of them were excluded from the reported indices.
- For each major event that is excluded, the utility must report the total number of customers affected, the number of customers without service at periodic intervals, the longest customer interruption, and the number of people used to restore service.
- Utilities must provide monthly SAIDI, SAIFI and system MAIFI on a circuit level upon request to any interested party.
- Utilities that have not collected reliability data in ways that conform to the state's operational definitions must use their best efforts to "normalize" their historical data for the last 10 years to reflect the state's operational definitions and provide information on such efforts with each annual report. The utilities' first annual reports must describe limitation in the utility's data that affect normalization, and provide their best estimate of the statistical error inherent in the normalized indices.
- Utilities must submit annual reports summarizing maintenance and operations inspections made, equipment conditions observed, and repairs made. (California has specific inspection and maintenance and tree trimming standards that are used when evaluating utility response to major outages.)
- The Public Utility Commission of the State of California's website provides the public with each utilities' annual reliability reports, analysis of the causes and planned corrections for the poor performing circuits, and annual maintenance inspection reports.
- Utilities must submit emergency response plans and updates and implement testing of their plans.

Illinois[2]

- Requires certain entities (utilities, alternative retail suppliers owning, controlling, or operating transmission and distribution facilities and equipment within the state) to submit an annual report that is used by the state to evaluate the entity's reliability and make recommendations to address potential reliability problems that are identified.[3] The report must be submitted under oath and verified by an individual responsible for the entities' transmission and distribution reliability. It must include:

Appendix C (Continued)

- A plan for future investment, and where necessary reliability improvements, for the company's transmission and distribution facilities along with estimated costs for implementing the plan and any plan changes from the previous report.
- A report of implementation of previous plans, including an identification of significant deviations from the previous plans and reasons for the deviations.
- The number and duration of planned and unplanned interruptions for the annual reporting period and their impacts on customers.
- The number and causes of controllable interruptions (i.e. interruption caused or exacerbated in scope and duration by the condition of facilities, equipment, or premises owned or operated by the company, or by the action or inaction of persons under a company's control and that could have been prevented through the use of generally accepted engineering, construction, or maintenance practices).
- Customer service interruptions that were due solely to the actions or inactions of another utility, another jurisdictional entity, independent system operator, or alternative retail electric supplier.
- A report of the age, current condition, reliability and performance of the existing transmission and distribution facilities, which include a summary of interruptions and voltage variances, the reliability indices for the annual reporting period, expenditures for transmission construction and maintenance for the annual reporting period expressed in constant 1998 dollars, expenditures for distribution construction and maintenance for the annual reporting period expressed in constant 1998 dollars, customer satisfaction with reliability, an overview of the number and substance of customers' reliability complaints for the annual period and their distribution over operating areas. (Corresponding information for the prior three years must also be reported.)
- A table showing for each operating area during the year, its achieved performance on each of three reliability indices. These include:
    - system Average Interruption Frequency Index (SAIFI);
    - customer Average Interruption Duration (CAIDI); and
    - customer Average Interruption Frequency Index (CAIFI).
- A list of the worst performing circuits for each operating area for the year.
- A statement of the operating and maintenance history of circuits designated as worst performing, a description of any action taken or planned to improve the performance of such circuits, and a schedule for completion of any such action.
- Tables or graphical representations, covering the last three years, showing in ascending order, the number of customers that experienced a set number of interruptions during the year.
- A list of every customer who experienced interruptions in excess of the service reliability targets, the number of interruptions and interruption duration experienced in each of the three preceding years, and the number of consecutive years in which the customer had experienced interruptions in excess of the service reliability targets.
- The name, address, and telephone number of the individual who can be contacted for additional information regarding the annual report.

➢ Provides reports to the public through the public utility commission's website.

Appendix C (Continued)

- Requires an electric utility to compensate[4] customers for all actual damages in the event that more than 30,000 customers are subjected to continuous power interruptions of four hours or more that results in transmission of power at less than 50 percent of standard voltage, or that results in the total loss of power transmission, and reimburse the affected local government unit in which the power interruption took place for all emergency and contingency expenses incurred as a result of the interruption.[5] Similar requirements are in place for power surge or other fluctuations that causes damage and affects more than 30,000 customers.

Maryland[6]

- Requires annual reporting by electric companies with more than 40,000 Maryland customers of CAIDI, SAIDI, and SAIFI reliability indices.
- Requires reliability indices reporting both with and without major event data included in the calculations.
- Defines a major event as occurring when more than 10 percent of a utility's Maryland, or bordering jurisdiction, customers are without service and restoration of these customers takes more than 24 hours. Such events must be identified in the report and include the time periods during which major event interruption data was excluded from the indices, and a description of the interruption causes during each time period.
- Requires investor-owed utilities to provide SAIDI, SAIFI and CAIDI reliability indices for 2 percent of feeders or 10 feeders, whichever is more, serving at least one Maryland customer that are identified by the utility as having poorest reliability.
- Requires that utilities report for two years the actions taken, if any, and their completion dates, to improve reliability for each of the feeders with the poorest reliability. In the third year, the utility must report the ranking of such feeders in terms of reliability during the current reporting period.
- Requires retention of momentary interruption data the utility collects for five years.

Massachusetts[7]

- Requires utilities to report on an annual basis:
  - SAIDI, SAIFI, CAIDI reliability indices.
  - Major outage events excluded from SAIDI and SAIFI reliability indices. Excludable major events are those that meet one of the following criteria: (a) the event is caused by earthquake, fire, or storm of sufficient intensity to give rise to a state of emergency being proclaimed by the Governor; (b) any other event that causes an unplanned interruption of service to 15 percent or more of the electric distribution company's customers in an operating area; or (c) an event that results from the failure or disturbance of a transmission, power supply, or other system that is not owned or operated by the electric distribution company. An extreme temperature condition that does not meet one of the above criteria does not constitute an excludable major event. For each major outage event excluded, the company must report:
    - Total number of customers affected,
    - Number of customers without service at periodic intervals,
    - Time frame of longest customer interruption,
    - Number of crews used to restore service on a per shift basis, and
    - Company policy on tree trimming, including tree trimming cycles, inspection procedures, and typical minimum vegetation clearance requirements from electric lines.
  - Lost Work Time Accident Rate.[8]

Appendix C (Continued)

    - Restricted Work Day Rate.[9]
    - Damage to company property.
    - Capital investments approved and completed in the company's transmission and distribution infrastructure (along with a summary list and location of each transmission and distribution facility that was modified, upgraded, replaced, and/or constructed as well as the costs and scope of work involved in the facility modifications, upgrade, replacement, and/or construction).
    - Company policy for identifying, acquiring, and stocking critical spare components for its transmission and distribution system (the initial report must describe how the policy has changed or evolved over the past ten years).
    - Poor performing circuits along with information about such circuits (the feeder or circuit identification number, the feeder or circuit location, the reasons why the circuits performed poorly during the reporting year, the number of years the circuits performed poorly, the steps that are being considered and/or have been implemented to improve the reliability of these circuits, and the SAIDI or SAIFI values for the specific circuits).
- Requires reporting of 10 years of prior data for most information included in annual reports.
- Requires submission of information, typically in the first annual report, describing limitations in the company data gathering and reporting that affect standardization of the reliability indices, and requires the company's best estimate of the statistical error inherent in the standardized indices.
- Allows a company that is not able to standardize its reliability data in order to conform with the state's definitions and requirements to submit reliability data using the company's own historic method if the company:
    - Demonstrates why it cannot reasonable convert the data to the method established by the state.
    - Calculates its historic average performance using its historic methods, and also reports SAIDI and SAIFI using the state's method.[10]
- Requires reporting to the Department of every outage. Such reporting must occur within one-hour from the beginning of the outage for every outage that results in 5,000 or more customer outage hours or that has a reasonable probability of involving a hospital, airport, large manufacturing, commercial, or institutional customer (who has a demand of 1 megawatt or greater). All other outages must be reported within a 24-hour period from the beginning of the outage.
- Requires outage reports, which may be updated, include:
    - Date of the outage.
    - Location of the outage (by providing town and street(s) location).
    - Nature or cause of the outage.
    - Number of customers affected.
    - Time outage commenced and time service was restored.
    - Duration of the outage.
    - Number of customer outage hours.
    - Feeder or circuit number.
    - District or division where outage occurred.
    - Identification of overhead or underground line where fault or outage occurred.
    - Name and telephone number of a utility employee who may be contacted about the outage.
    - Approximated number of crew(s) involve in the power restoration,
    - Whether the outage is considered an Excludable Major Event.

Appendix C (Continued)

Michigan[11]

- Requires quarterly reporting of the utility's systems' monthly data on its success in restoring service to interrupted customers within specific periods of time. The information is reported for all operating conditions, after the occurrence of catastrophic events, and under normal operating conditions.
- Requires quarterly reporting of data regarding same-circuit repetitive interruptions (i.e. a grouping of more than 10 customers on a circuit who experience multiple interruptions under all operating conditions.)

New Jersey[12]

- Requires each utility to substantially implement an Outage Management System (OMS) by December 31, 2000 that consists at a minimum of a fully integrated geographic information system (GIS), a sophisticated voice response unit (VRU), a software driven outage assessment tool and an energy management system/supervisory control and data acquisition (EMS/SCADA). The OMS when fully implemented must be able to digitally map the entire electric distribution system, group customers who are out of service to the most probable interrupting device that operated, associate customers with distribution facilities, generate street-maps indicating outage locations, improve the management of resources during a storm, improve the accuracy of identifying the number of customers without service, accurately communicate the number of customer without electric service and improve the ability to estimate their restoration time, accurately communicate the number and when customers were restored, and dispatch crews and/or troubleshooters via computer (mobile data terminals).
- Requires annual reporting of 10 years of SAIFI and CAIDI reliability indices for the utility system and each operating area (i.e. regions, divisions, districts). The utility may exclude data on its performance during major events from its calculations of the indices.
- Defines major events that are excluded from the reliability calculations to include: (a) thunderstorms, tornadoes, hurricanes, heat waves or snow and ice storms which affect at least 10 percent of the customers in an operating area, (b) situations where an unaffected utility operating area is providing assistance to an affected areas, (c) unscheduled interruption of service resulting from action taken by the utility under direction of the Independent System Operator, to prevent an uncontrolled or cascading interruption of service, or to maintain the adequacy and security of the electric system, including emergency load control, emergency switching and energy conservation procedures, which affect more than one customer, (d) an event sufficient to give rise to a state of emergency or disaster being declared by State government, and (e) situations where mutual aid is being provided to another utility and the assisting utility applies to the commission for permission to exclude its sustained interruptions from its CAIDI and SAIFI calculations.
- Requires submission within 15 business days of a report on each major event. The report must include the date and time when the utility storm center opened and closed, the total number of customer out of service over the course of the event over four hour intervals identified by operation area or circuit area, the date and time when the last customer affected by the event is restored, the number of trouble locations and classifications, the time at which mutual aid and non-company contractor crews are requested, arrived for duty and were released, and the mutual aid and non-contractor line and tree crews working on restoration activities during the duration of the event, and the timeline profile of the number of company crews sent to an affected operating area to assist in the restoration effort.

Appendix C (Continued)

- Requires that each utility have inspection and maintenance programs for its distribution facilities and annual submission of compliance plans.
- Requires each utility to identify and analyze poor performing circuits and take appropriate actions to improve reliability performance and upon request of the commission to identify the reliability performance of any circuit on its system.

New York[13]

- Requires monthly, and in some cases immediate, reporting of all service interruptions of five minutes or more (including planned interruptions). A major utility's monthly report must include the name of the corporation, the operating area for which the report is applicable, the number of interruptions by specific interruption cause, the total duration in customer-hours of those interruptions, the approximate total number of customer affected, the average number of customer served. The report must include data for the month and for the year-to-date. New York regulations include definitions of causes to be used in the report.
- Requires utilities to annually report their CAIDI and SAIFI reliability indices for their system and operating areas (i.e. regions, divisions, or districts). Major storms and catastrophic events are excluded from the calculation of the indices.
- Defines major storms as those causing interruptions to 10 percent of the customers in an operating area or causing interruptions greater than 24 hours. Catastrophic events may also be excluded from the reliability indices calculations if justified.
- Requires each utility to develop and maintain a program for analyzing its worst performing circuits during the course of each year. The analysis must include at a minimum five percent of the company's circuits.
- Requires each utility to annually submit a description of its program for analyzing worst-performing circuits and a summary of the results of the program, a description of its reliability program noting changes from the prior year, and a status report on the utility's power quality program, including the number of complaints received and the number of investigation conducted during the year, and a listing of circuit performance, by operating area, based on SAIFI and CAIDI performance for the calendar year.

Ohio[14]

- Requires utilities to annually report and submit CAIDI, SAIDI, SAIFI, and ASAI[15] reliability indices. The indices are reported with performance during a major storm included and excluded for each of the indices.
- Allows the utility to use its own definition of major storm when calculating the reliability indices subject to the review and acceptance of the utility's definition by the public utility commission's director of consumer services.
- Requires each utility to submit performance targets and supporting justification for each of the reliability indices to the public utility commission's director of the consumer services department. Such performance targets must reflect the utility's historical system performance, system design, service area geography, and other relevant factors. If the utility and the director of consumer service department cannot agree on performance targets, the utility staff and/or the company may apply to the commission for a hearing to resolve the matter.
- Requires each utility to develop a method for calculating circuit performance based on CAIDI, SAIFI, and other factors for review and acceptance by the public utility commission's director of consumer services. If the company and the director cannot

agree to a proposed method, the staff and/or company may apply to the commission for a hearing to resolve the matter.

- Requires submission of a semiannual report that identifies the lowest performing four percent of the utility's distribution circuits for the previous 12-month period. The report must provide for each reported distribution circuit, its identification number, location and primary service area, approximate number of customers served, number of outages and their causes, along with a description of and the rationale for any remedial action taken or planned to improve circuit performance, or for taking no remedial action, and the start and completion date for any remedial action taken or planned.
- Requires immediate outage reporting for service interruptions projected to last four hours or more when such interruptions involve 2,500 customers in an area, or a utility, water-works company, sewage disposal system, police or fire department, hospital, or county 9-1-1 system. Such reporting is also required when 100 or more customers are projected to be without service for 24 hours or more.
- Requires maintenance and submission of an emergency plan and amendments which must include a:
  - Description of procedures a utility uses to move from normal operations to each stage or level of outage response and restoration of service.
  - Description of the requirements for restoring services.
  - Contingency identification (i.e. plan for training alternative or backup staff, identifying back up power supplies, identifying alternative means for communicating with the office and field staff).
  - List of twenty-four hour phone numbers of fire and policy departments and county/regional emergency management directors in the service area.
  - Procedure for requesting aid, utilizing crews from other electric transmission owners and/or distribution companies, and other restoration assistance.
  - Procedure for prompt identification of outage areas, how to timely assess damage, and as accurately as conditions allow, provide an informed estimate of materials, equipment, personnel, and hours required to restore service.
  - Performance objectives and procedures for telephone response time to customer outage calls.
  - Policy and procedure for outage response and restoration of service by priority and a list of such priorities, including "live wire down" situations, restoration of power to police, fire, hospital, 9-1-1 and other essential services.
  - Procedure for providing information to customers or consumers on a medical or life-support system who had identified themselves to the utility and for whom an interruption of service would be immediately life-threatening and who are without service.
  - Policy and procedures for providing outage response and restoration of service updates to county/regional emergency management directors and other officials, the commission, the media, and utility customers.
  - Policy and procedures to verify service has been restored in each outage area.
  - Policy and procedures for providing maximum outage response, seeking outside assistance, and restoring service in a worst case weather scenario.
  - Policy and procedures to establish and maintain a liaison with appropriate fire and police departments within the service territory, notify appropriate fire, police, and other officials when major interruptions of service occur, and communicate with such parties during major restoration efforts.
- Requires each utility to annually submit a report to the commission with amendments and updates to the utility's emergency plan and providing a summary of:

Appendix C (Continued)

  - o Failures of equipment and facilities that resulted in major interruption of service and the company implementing its emergency plan.
  - o Company efforts to minimize the possibility of recurrence of such failures.
- ➢ Requires each utility every three years to conduct a comprehensive emergency exercise to test and evaluate major components of its emergency plan with the involvement of county/regional emergency management directors, fire and police departments, community organizations, and public utility commission staff.
- ➢ Requires each utility to submit, for review and acceptance by the commission's director of consumer services, the methodology it uses to assess the reliability of its transmission circuits based on the total number of sustained outages per circuit per calendar year and other factors proposed by the utility. The submission must include supporting justification for the utility's methodology. The utility and/or commission staff can request a hearing before the commission if agreement on the method cannot be reached.
- ➢ Requires each utility to submit an annual report that identifies the performance of each transmission circuit during the previous calendar year that includes at a minimum the following information for each circuit: its identification number, location, number of outages and their causes by individual circuit, the substation(s) and/or distribution circuits affected by each of the outages reported, a description of and the rationale for any remedial action taken or planned to improve circuit performance or for taking no remedial action, and the start and completion dates of any remedial action taken or planned.
- ➢ Requires each utility at a minimum to inspect its electric transmission and distribution facilities (circuits and equipment) to maintain safe and reliable service on the following schedule:
  - o Inspect at least one-fifth of the distribution circuits and equipment annually, with all circuits and equipment inspected at least once every five years.
  - o Inspect all transmission circuits and equipment at least once every year.
  - o Inspect all transmission and distribution substations and equipment at least once each month.
- ➢ Requires each utility to file an annual report on its compliance with the minimum inspection schedule.
- ➢ Requires each utility to establish and maintain written programs and schedules for inspection, maintenance, repair, and replacement of its transmission and distribution circuits and equipment that establish preventative requirements for the electric utility to maintain safe and reliable service. The utility programs must include, but are not limited to, the following facilities: poles and towers, conductors, pad-mounted transformers, line reclosers, line capacitors, right-of-way vegetation control, and substations.
- ➢ Requires each utility to submit a plan for the inspection, maintenance, repair, and replacement of circuits and equipment for review and acceptance by the public utility commission's director of consumer services. The submission must include supporting justification and rationale based upon historic practices and procedures used by the utility over the past five years. If the parties cannot reach agreement on the details and contents of the plan, either party may file a request for a hearing with the commission.
- ➢ Requires each utility to submit for review and acceptance all revisions to the inspection, maintenance, repair and replacement plan prior to the calendar year in which the revisions will be implemented.
- ➢ Requires each utility to maintain records sufficient to demonstrate compliance with its transmission and distribution facilities inspection, maintenance, repair, and replacement programs.

See Footnotes to Appendix C on the following page.

Footnotes to Appendix C

[1]California enacted legislation restructuring the electric utility industry in September 1996. The legislation provided for rate reductions and a rate freeze for residential customers.

[2]In December 1997, Illinois enacted legislation to restructure the electric power industry. The legislation provides for consumer rate cuts and rate reductions.

[3]The evaluation is required by statute to be carried out at least every three years.

[4](4)Loss of revenues and expenses incurred by the utility for such compensation may not be recovered from ratepayers.

[5]A waiver may be granted in instances in which the utility can show that the interruption was a result of unpreventable damage due to weather events or conditions, customer tampering, unpreventable damage due to civil or international unrest or animals, or damage to utility equipment or other actions by a party other than the utility, its employees, agents, or contractors.

[6]Maryland enacted electric utility restructuring in April 1999. The legislation provides for rate reductions for residential customers.

[7]Massachusetts enacted legislation restructuring the electric power industry in November 1997. The legislation provides for rate cuts.

[8]The Incidence Rate of Lost Work Time injuries and Illness per 200,000 Employee Hours as defined by the U.S. Department of Labor Bureau of Labor Statistics.

[9]The Incidence Rate of Restricted Work cases per 200,000 Employee Hours as defined by the U.S. Department of Labor Bureau of Labor Statistics.

[10]When Massachusetts enacted utility restructuring legislation in November 1997, its legislation directed the Department of Telecommunications and Energy to levy "a penalty against any distribution, transmission, or gas company which fails to meet the service quality standards in an amount up to and including the equivalent of two percent of such company's transmission and distribution revenues for the previous calendar year." The legislation specifies that in complying with the service quality standards, no labor displacement or reductions below staffing levels in existence on November 1, 1997 may take place unless they are part of a collective bargaining agreement or otherwise approved by the Department. Financial penalties are incurred for performance between one and two standard deviations above the utility's historic average performance. A formal investigation is initiated when performance is more that two standard deviations above the historic average. For utilities meeting the conditions noted in the text above, Massachusetts is willing to use the utility's historic performance data calculated using the utility's definitions rather than the state "standardized" data to establish the standards that must be met to avoid imposition of the financial penalties provided for in statute. The historic averages for purposes of performance-based rates are based on five years of data (1996-2000), rather than the ten years required for annual reporting. Massachusetts' performance-based rate setting includes many elements in addition to SAIDI and SAIFI (e.g., telephone answering rate and response to gas odor calls). The system does not provide payments for improved performance, however, "better than historic performance" in a given year in one area (e.g. response to gas odor calls) can be used to off set a financial penalty that otherwise would have been imposed due to "poorer than historic performance" in another area (e.g. electric system reliability as measured by SAIFI).

[11]In June 2000, Michigan enacted legislation to restructure the electric power industry. The legislation provides for immediate rate reductions and freezing of the reduced rates.

[12]New Jersey enacted legislation to restructure the electric power industry in February 1999. The legislation provides for consumer rate reductions.

[13]New York did not enact legislation. The New York Public Service Commission issued a decision in May 1996 to restructure New York's electric power industry.

[14]Ohio enacted legislation to restructure electric utility industry in July 1999. The legislation provides for residential rate reductions and rate freezes.

[15]ASAI, or average system availability index, is the ratio of time the system provided service to each customer.

APPENDIX D

Footnotes to Exhibit 11 "Selected State Reporting Requirements for Service Interruptions"

[a]Illinois defines controllable interruptions as those caused or exacerbated in scope and duration by the condition of facilities, equipment, or premises owned or operated by the company, or by the action or inaction of persons under a company's control and that could have been prevented through the use of generally accepted engineering, construction, or maintenance practices.

[b]Massachusetts' definition of a major outage event includes events that result from failure or disturbance of a transmission, power supply, or other system that is not owned or operated by the company.

[c]Public street and highway lighting and sales to other utilities are excluded from the reporting.

[d]Insert cite.

[e]The term does not include interruptions occurring at a time of routine adverse weather.

[f]Interruptions resulting from conductors or energized equipment coming in contact with a tree (or vice versa), except when the tree or limb is felled by lightning or by an employee, contractor, or customer. Interruptions cause by a tree or limb felled by a utility employee or utility contractor are classified as "operating or working errors," and as "accidents or events not under utility control" if felled by a customer or a nonutility contractor. Trees felled by lightning are reporting under the category "lightning."

[g]Interruptions from blowing of a transformer and/or line fuse through overload. The category does not include those interruptions resulting from increased or abnormal customer loads or generation for which the customer is required to notify the utility, but failed to do so.

[h]Interruptions resulting from errors by utility or utility contact personnel. Such interruptions include, for example, improper or substandard installation or design of facilities or the installation of improper equipment, and a utility's employee or contractor dropping a limb on a conductor.

[i]Interruptions resulting from the breakdown or failure of otherwise properly selected, installed, and protected equipment and facilities, including transformer failures (not due to external factors), broken poles or crossarms, faulty protective devices, cracked (not by gun fire) or contaminated insulators, defective cutouts, crossed or broken line and tie wires (not cause by tree contacts or lightning), improper relay operations, substandard conditions that were not present when the facilities were initially installed (e.g. slack conductors).

[j]Interruptions resulting from events not under the control of the utility or its employees or contractors, such as house fires not caused by the utility's service; gun fire; crane contacts; automobile accidents; squirrel, bird, or other animal contacts; sabotage; customer tree felling.

[k]Interruptions resulting from actions deliberately taken by the utility upon advance notice to the customers affected (prearranged). Deliberate interruptions (lasting at least five minutes) without prior notice to the customer affected are reported under the classification most directly related to the reasons the outage was needed. They are considered part of a forced interruption when they take place during emergency conditions to facilitate restoration.

[l]Interruption resulting from the failure of a customer's equipment or from failure of a customer to take required actions (such as failure to notify the utility of an increase in load when required by agreement with the utility). The customer's problem may cause an interruption to other customers or a problem on the utility system.

[m]Interruptions caused by lightning include those resulting from either direct strikes, or indirect immediate effects of lightning, on transformers, oil switches, cutout, so long as the equipment hit or indirectly affected was in proper condition prior to the lightning. An interruption resulting from a lightning strike to a tree limb that then comes in contact with or knocks down conductors is included in this category.

[n]Interruptions for which the cause in unknown or for which none of the other classifications is appropriate. The classification is not to be used if an investigation could determine the proper cause of an interruption for which one of the other classifications would be more appropriate.

[o]Utilities with network systems serving 10 percent or more of the operating area's load must report information separately for their radial and network system interruptions.

APPENDIX E

May 23, 2002, PUC Order

PENNSYLVANIA
PUBLIC UTILITY COMMISSION
Harrisburg, PA 17105-3265

Public Meeting held May 23, 2002

Commissioners Present:

Glen R. Thomas, Chairman
Robert K. Bloom, Vice Chairman
Aaron Wilson, Jr.
Terrance J. Fitzpatrick
Kim Pizzingrilli

Review of Commission Role in Monitoring Electric Service Reliability Performance

Docket Number: D-02SPS021

ORDER

BY THE COMMISSION:

The Electricity Generation Customer Choice and Competition Act became effective January 1, 1997. The purpose of the Act was to create the opportunity for direct access to a competitive market for retail electric generation while maintaining the safety and reliability of the electric system. Specifically, the Commission was given a legislative mandate to ensure that levels of reliability that were present prior to the restructuring of the electric utility industry would continue in the new competitive markets.

On April 23, 1998, the Commission adopted a final rulemaking to amend 52 Pa. Code Chapter 57 to ensure the safety, adequacy and reliability of the generation, transmission and distribution of electricity in the Commonwealth.[1] Section 57.194 of

1 Final Rulemaking to Amend 52 Pa. Code Chapter 57 to Ensure Electric Service Reliability, Docket No. L-00970120.

the Commission's regulations details the requirements of electric distribution companies (EDCs) to ensure distribution system reliability, including the establishment of service reliability performance benchmarks and standards.

On April 30, 1999, after an opportunity for comments, the Commission issued reliability benchmarks and standards for the operating areas of each EDC.[2] Temporary benchmarks were based on an average of historic performance data for the five-year period 1993-1997. Temporary performance standards (i.e., minimum standards) were established as two standard deviations above the mean historic values. Note that higher values mean a higher level of tolerance and thus lower performance for the indices measured. The Commission stated that it would establish permanent benchmarks and standards subsequent to receiving the initial reliability reports, pursuant to section 57.195 of the Commission's regulations.

The initial reliability reports were subsequently received from all jurisdictional EDCs, and on August 27, 1999, the Commission issued a Tentative Order to provide an opportunity for EDCs and other affected parties to provide comments on the proposed establishment of permanent electric service reliability performance benchmarks and standards. Based on the comments of the interested parties, the Commission ordered the establishment of permanent electric service reliability performance benchmarks and standards on December 16, 1999.

The permanent benchmarks were based on a five-year historic average, which was calculated using 1994-1998 data. Permanent minimum performance standards were established as two standard deviations above the mean historic value for the same period. The Commission acknowledged, however, that since technological advancements in data collection could significantly change performance indicators, a

[2] Docket No. M-00991220, April 29, 1999.

future reevaluation of these benchmarks and standards would most likely be appropriate.

The Commission has been actively monitoring electric service reliability performance through various methods, including customer complaint information maintained by the Bureau of Consumer Services, PEMA reporting requirements and various audit functions. Based upon the results of those monitoring efforts, over the past two years, some companies have voluntarily agreed to corrective actions where appropriate and increased reporting requirements. The reliability annual reporting requirements have been in existence for two years, with the third year of data due May 31, 2002.

As part of our overall responsibility to address reliability and to insure that current structures and requirements meet this obligation, a Staff Internal Working Group on Electric Service Reliability was established. The Group's ongoing assignment is to review and to make recommendations with respect to the Commission's reliability monitoring process. The internal working group is comprised of members of Commission bureaus having direct or indirect responsibility for monitoring service reliability. The group began meeting in February, 2002. Based upon an internal review of filed reports and the Commission's own reporting regulations and standards, the group has tentatively identified several areas for further research and possible improvement:

- The methodology for establishing electric service reliability standards should be reviewed to determine if revision is needed to ensure higher levels of company performance.

Appendix E (Continued)

- The Commission should review the definitions of a Major Event and an Operating Area under Chapter 57 to ensure consistent reporting of reliability performance by all EDCs.

- The current system for reporting service reliability performance should be modified to provide for more comprehensive and timely information.

- Internal communication within the Commission should be enhanced so that all persons involved with monitoring service reliability are current with all EDC reports and Commission activities.

Based upon these preliminary findings, there is a sufficient basis to direct the internal working group to further explore these and other issues and to submit a further, comprehensive report for the Commission's consideration and decision.

It should be noted that the Legislative Budget and Finance Committee (LB&FC) has also been intensely reviewing the Commission's role in monitoring reliability. The Commission anticipates receiving LB&FC's final report in the near future and, consistent with other LB&FC reports, that there will be recommendations addressing the Commission's role. We look forward to receiving the LB&FC report as it will further augment the Commission's efforts in this regard as the LB&FC's comprehensive review of our efforts will allow us to more effectively monitor electric distribution reliability.

The Commission is cognizant of its oversight responsibilities with respect to reliability monitoring under the Electricity Generation Customer Choice and Competition Act. Moreover, as we recognized in the 1998 reliability rulemaking, the Commission will continue to reevaluate the effectiveness of its regulations and practices in the reliability area, and make improvements where necessary.

Appendix E (Continued)

For the above reasons, we direct that the Staff Internal Working Group on Reliability complete its work no later than July 15, 2002 and submit a final report to the Commission for consideration and further action. Staff's report will address current reporting requirements, monitoring efforts and coordination of the Commission efforts to monitor electric distribution reliability. It will include an analysis of existing EDC reliability reporting practices and provide the Commission with specific recommendations to address any potential or existing problems with respect to reliability as well as how both the Commission and the industry can work to enhance system reliability. The report will also include an analysis of the findings and recommendations in the LB&FC report; **THEREFORE,**

IT IS ORDERED:

1. That the Commission Staff Internal Working Group on Electric Service Reliability, consistent with the discussion contained in this order, will provide this Commission with a final report on electric distribution reliability by July 15, 2002.

2. That a copy of this Order will be served upon all jurisdictional electric distribution companies, the Office of Consumer Advocate and the Office of Small Business Advocate.

BY THE COMMISSION,

James J. McNulty
James J. McNulty
Secretary

(SEAL)

ORDER ADOPTED: May 23, 2002

ORDER ENTERED: MAY 2 3 2002

Source: Pennsylvania Public Utility Commission.

APPENDIX F

1999 and 2000 Company Reliability Performance Actual Index Values and Historic Performance Levels*

		CAIDI Index	SAIFI Index	SAIDI Index
PECO	2000	100	1.04	105
	1999	148	1.34	198
	Historic Performance Level[a]	112	1.23	138
PPL	2000	130	0.97	126
	1999	148	0.89	132
	Historic Performance Level	128	0.88	113
Allegheny Power	2000	206	0.84	173
	1999	216	0.78	169
	Historic Performance Level	178	0.67	116
GPU	2000	162	0.98	159
	1999	119	1.08	128
	Historic Performance Level	110	1.02	110
Duquesne	2000	87	1.26	109
	1999	88	1.28	113
	Historic Performance Level	108	1.15	123
Penn Power	2000	104	1.73	180
	1999	110	1.31	144
	Historic Performance Level	93	1.01	95
UGI	2000	117	0.62	72
	1999	121	0.84	102
	Historic Performance Level	169	0.83	147

*Note: An increase in the reliability value over the historic performance level is an indicator of diminished performance.

[a]Average value of the reliability index for 1994 through 1998 as identified by the PUC in December 1999.

Source: Developed by LB&FC staff from Pennsylvania PUC electric service reliability benchmarks for systems and data reported to the PUC for 1999 and 2000.

APPENDIX G

Complete and Incomplete Service Outage Reports Submitted to the PUC

PECO:

Year	Total Reports	Complete Reports	Reports Missing Key Information
2001	2	2	0
2000	3	2	1
1999	10	8	2
1998	5	4	1
1997	1	1	0
1996	2	2	0
1995	3	3	0
1994	No Reports	No Reports	No Reports
1993	3	3	0
1992	1	1	0

PPL:

Year	Total Reports	Complete Reports	Reports Missing Key Information
2001	1	1	0
2000	7	7	0
1999	5	4	1
1998	2	2	0
1997	No Reports	No Reports	No Reports
1996	1	0	1
1995	5	2	3
1994	2	2	0
1993	4	2	2
1992	3	3	0

Allegheny Power/West Penn:

Year	Total Reports	Complete Reports	Reports Missing Key Information
2001	6	0	6
2000	4	3	1
1999	5	5	0
1998	3	3	0
1997	6	1	5
1996	1	1	0
1995	3	3	0
1994	3	3	0
1993	3	3	0
1992	3	3	0

Appendix G (Continued)

GPU:

Year	Total Reports	Complete Reports	Reports Missing Key Information
2001	6	0	6
2000	5	0	5
1999	3	0	3
1998	3	0	3
1997	2	0	2
1996	2	0	2
1995	6	2	4
1994	No Reports	No Reports	No Reports
1993	3	0	3
1992	1	1	0

Duquesne Light:

Year	Total Reports	Complete Reports	Reports Missing Key Information
2001	1	1	0
2000	2	1	1
1999	2	2	0
1998	2	2	0
1997	3	3	0
1996	2	2	0
1995	4	4	0
1994	5	5	0
1993	2	2	0
1992	2	2	0

Penn Power:

Year	Total Reports	Complete Reports	Reports Missing Key Information
2001	No Reports	No Reports	No Reports
2000	1	1	0
1999	3	3	0
1998	No Reports	No Reports	No Reports
1997	No Reports	No Reports	No Reports
1996	No Reports	No Reports	No Reports
1995	1	0	1
1994	No Reports	No Reports	No Reports
1993	No Reports	No Reports	No Reports
1992	No Reports	No Reports	No Reports

Appendix G (Continued)

UGI:

Year	Total Reports	Complete Reports	Reports Missing Key Information
2001	No Reports	No Reports	No Reports
2000	No Reports	No Reports	No Reports
1999	1	0	1
1998	No Reports	No Reports	No Reports
1997	No Reports	No Reports	No Reports
1996	No Reports	No Reports	No Reports
1995	No Reports	No Reports	No Reports
1994	No Reports	No Reports	No Reports
1993	No Reports	No Reports	No Reports
1992	No Reports	No Reports	No Reports

Source: Developed by LB&FC staff from PUC service outage reports.

APPENDIX H

Pennsylvania Public Utility Commission's Response to This Report

PENNSYLVANIA PUBLIC UTILITY COMMISSION
COMMONWEALTH OF PENNSYLVANIA
P.O. BOX 3265
HARRISBURG, PENNSYLVANIA 17105-3265

GLEN R. THOMAS
CHAIRMAN

TELEPHONE
(717) 783-7349
e-mail
Pucchairman@state.pa.us

June 6, 2002

Mr. Philip R. Durgin
Executive Director
Legislative Budget & Finance Committee
Room 400, Finance Building
Harrisburg, PA 17120

Dear Mr. Durgin:

Thank you for the opportunity to review your draft report on *Assessing the Reliability of Pennsylvania's Electric Transmission and Distribution Systems*. Your staff has conducted an impartial review of this matter and has provided constructive recommendations and insights for the Commission's consideration.

As you are aware, the Commission takes its responsibility for monitoring reliability very seriously and understands its importance in traditional and newly competitive markets. To that end, the Commission has, at Docket No. D-02SPS021, directed its Internal Working Group on Electric Service Reliability to provide the Commission with a final report on electric distribution reliability by July 15, 2002. This Working Group report will include an analysis of the findings and recommendations in your report.

I thank you again for your efforts and the opportunity to respond to this report. The Commission will continue to ensure reliability of the electric system and welcomes your report as a guide to further improving the Commission's effectiveness in this important area.

Sincerely,

Glen Thomas

GLEN R. THOMAS
Chairman