BEFORE THE STATE OF NEW JERSEY
OFFICE OF ADMINISTRATIVE LAW
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE PETITION	**) BPU DKT. NO. GR09030195**
OF PIVOTAL UTILITY HOLDINGS, INC.	**) OAL DKT. NO. PUC-03655-2009N**
D/B/A ELIZABETHTOWN GAS FOR	**)**
APPROVAL OF INCREASED BASE TARIFF	**)**
RATES AND CHARGES FOR GAS SERVICE	**)**
AND OTHER TARIFF REVISIONS	**)**

DIRECT TESTIMONY OF RICHARD LELASH ON BEHALF OF THE NEW JERSEY DEPARTMENT OF THE PUBLIC ADVOCATE DIVISION OF RATE COUNSEL

PUBLIC VERSION -- REDACTED

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PIVOTAL UTILITY HOLDINGS, INC.
DOCKET NO. GR09030195
TESTIMONY OF RICHARD W. LELASH

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I. STATEMENT OF QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS FOR THE RECORD.

A. My name is Richard W. LeLash and my business address is 18 Seventy Acre Road, Redding, Connecticut.

Q. WHAT IS YOUR CURRENT BUSINESS AFFILIATION?

A. I am an independent financial and regulatory consultant working on behalf of several state public utility commissions and consumer advocates.

Q. PRIOR TO YOUR WORK AS AN INDEPENDENT CONSULTANT, WHAT WAS YOUR BUSINESS AFFILIATION, AND WHAT WAS YOUR REGULATORY EXPERIENCE?

A. I was a principal with the Georgetown Consulting Group for twenty years. During my affiliation with Georgetown, and continuing to date, I testified on cost of service, rate of return, and regulatory policy issues in more than 300 regulatory proceedings. These testimonies were presented before the Philadelphia Gas Commission, the Federal Energy Regulatory Commission and in the following jurisdictions: Alabama, Arizona, Colorado, Delaware, District of Columbia, Georgia, Illinois, Kansas, Maine, Maryland, Minnesota, Missouri, New Jersey, New Mexico, New York, Ohio, Oklahoma, Pennsylvania, Rhode Island, U.S. Virgin Islands, and Vermont.

Q. MR. LELASH, WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I graduated in 1967 from the Wharton School with a BS in Economics and in 1969 from the Wharton Graduate School with an MBA.

Q. DURING THE COURSE OF YOUR REGULATORY WORK, WHAT HAS BEEN YOUR EXPERIENCE WITH GAS POLICY AND REGULATION?

A. Since 1980, I have worked extensively on gas utility matters. In my Appendix there is a listing of the recent cases in which I have sponsored testimony. In addition to these cases, I have reviewed and analyzed many other gas filings which were resolved through stipulation. Among other issues, my testimonies have involved gas service unbundling, physical and economic bypass, base rate levels, gas plant remediation costs, gas price hedging, demand and capacity planning, gas service measures, regulatory policy, and least cost gas standards. In addressing these issues, I have analyzed gas regulatory filings and have provided testimony involving more than 30 different gas utilities.

Q. DO YOU HAVE ANY SPECIFIC EXPERIENCE WITH RESPECT TO THE OPERATIONS OF ELIZABETHTOWN GAS?

A. Yes. Previously I have worked in various proceedings involving the Company. The testimonies have involved affiliate audits, MGP gas remediation, gas procurement, merger issues, and general gas policy matters.

Q. DO YOU HAVE ANY SPECIFIC EXPERIENCE WITH RESPECT TO POLICY MATTERS FOR NATURAL GAS DISTRIBUTION COMPANIES IN NEW JERSEY?

A. Yes. In the past, I have worked on and testified on behalf of Rate Counsel and its predecessor, the Ratepayer Advocate, on various matters concerning all four of New Jersey's gas distribution companies.

II. SCOPE AND PURPOSE OF TESTIMONY

Q. WOULD YOU PLEASE STATE THE SCOPE AND PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I was hired by the New Jersey Rate Counsel ("Rate Counsel") to review the filing made by Pivotal Utility Holdings ("Company" or "ETG") and evaluate various policy issues using established regulatory standards. My review focused on Conservation Incentive Program ("CIP"), merger related, and performance issues for the Company.

The purpose of my testimony is to present findings and recommendations to the New Jersey Board of Public Utilities ("Board" or "BPU") concerning issues raised by the Company's filing.

Q. IN PERFORMING YOUR REVIEW AND ANALYSIS, WHAT DATA SOURCES DID YOU UTILIZE?

A. My review and analysis encompassed the Company's filing, responses to discovery requests and information provided in previous proceedings.

Q. WERE THERE ANY LIMITATIONS PLACED ON YOUR REVIEW AND ANALYSIS OF THE COMPANY'S FILING?

A. As of the time this testimony was prepared, the Company had recently made its 6+6 updated filing, and the discovery process on the update had not been completed. Additionally, certain issue areas in the case will be addressed in Rate Counsel's testimonies that are to be filed by other witnesses. Accordingly, I would like to reserve the right to amend or supplement this testimony concerning the Company's updates and policy issues that may be subsequently filed by other Rate Counsel witnesses.

Portions of this testimony were also developed in collaboration with Dian Callaghan, another Rate Counsel witness. We worked together on the specification of service metrics and performance benchmarks for gas utilities in general and for the operations of the Company specifically as discussed in her testimony.

Q. WAS THIS TESTIMONY PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes, this testimony was prepared by me.

III. OVERVIEW AND CONCLUSIONS

- Rate Counsel's Issues and Witnesses

Q. WOULD YOU PLEASE PROVIDE A DESCRIPTION OF YOUR TESTIMONY AND THE TESTIMONIES THAT ARE BEING FILED BY OTHER RATE COUNSEL WITNESSES?

A. My testimony addresses several issues, principally those dealing with matters related to the merger, service levels, the initiation of an Efficiency and Usage Adjustment ("EUA") mechanism, and general policy areas. Additionally, other testimonies addressing the Company's base rate filing will be sponsored by the following Rate Counsel witnesses:

1. Robert Henkes of Henkes Consulting will testify about the Company's revenue requirements and related accounting and regulatory policy issues, as well as addressing the testimony of Michael Morley.

2. Dian Callaghan of the McFadden Consulting Group will testify about service standards and the Company's overall performance measures and will address the testimony of Connie McIntyre.

3. Matthew Kahal of Exeter Associates will testify concerning the appropriate rate of return for the Company and will address Roger Morin's testimony.

4. Brian Kalcic of Excel Consulting will testify about cost of service and rate design issues as well as addressing the filed testimony of Daniel Yardley.

5. Michael J. Majoros, Jr. of Snavely King Majoros O'Connor & Lee will testify about the appropriate approach for establishing depreciation rates for the Company and the testimony of Kimbugwe Kateregga.

6. Michael J. McFadden, A. E. Middents and John Peters of the McFadden Consulting Group will address Don Carter's testimony concerning the Company's operations, construction program and its operation and maintenance of its gas system.

7. David Peterson of Chesapeake Regulatory Consultants will testify about the Company's determination of its cash working capital and will address Robert DePriest's lead lag study.

- Summary of Findings and Recommendations

Q. WOULD YOU PLEASE SUMMARIZE YOUR DIRECT TESTIMONY IN THIS MATTER?

A. Based on my review and analysis, I propose that the Board adopt the following findings and recommendations:

1. The Company's proposed revenue decoupling mechanism should not be authorized in this proceeding. The results of such mechanisms authorized for the New Jersey Natural Gas Company ("NJNG") and South Jersey Gas Company ("SJG") as pilot programs will be evaluated at the end of their current programs. Accordingly, any prospective decoupling mechanism needs full evaluation by various stakeholders in order to determine both the desirability and the structure of such riders in the future.

2. In order to fully examine decoupling mechanisms and their impact on gas utilities and their ratepayers, the Board should initiate a generic proceeding for its gas utilities to consider the existing pilot programs, the program proposed by ETG, and any decoupling mechanisms to be authorized prospectively.

3. The Company's transition costs associated with the relocation of its call center should not be charged to its ratepayers. Ratepayers have already paid for ineffective call center relocations and they have had to endure inferior service levels for a considerable period of time. On this basis, the Company should be required to absorb its one-time transition costs of $740,386 associated with its call center operation.

4. The Company has also proposed that its internal remediation adjustment clause ("RAC") costs be recovered through base rates. However, there is no logic to segregating such internal costs from all of the other remediation expenditures. An established procedure is in place for all of the Company's manufactured gas plant ("MGP") remediation costs and the referenced internal costs should be subject to this annual review process rather than the infrequent base rate investigations.

5. Additionally, the Company is seeking base rate recovery of $940,000 of conservation costs. However, since all other conservation costs are recovered through the Regional Greenhouse Gas Initiative ("RGGI") tariff, there appears to be no reason to not have this amount also recovered through the RGGI tariff. It is not reasonable to assume that $940,000 of

conservation costs will be representative of future cost levels, and thus, base rate recovery of a fixed amount is inappropriate.

6. Unfortunately, there has been a disconnect between the on-going affiliate and management audits of the Company and this base rate proceeding. Because of the delay in the audits, the Board's order in this proceeding should be made subject to modification if the audits find that the Company has not fulfilled its merger requirements. Such modifications, based on appropriate evidence, should include adjustments to revenue requirements or the imposition of penalties for the Company.

7. Several of the operating areas that were to benefit from the merger have not shown any major improvement. Centralization of certain functions by AGL Services Company ("AGLSC") has not improved operations. Basic performance measures, concerning various customer related activities, show limited improvement, and in several areas, the Company's performance is not up to industry standards. The Company's call center, its responses to leak reports, and its overall level of customer complaints still need improvements more than four years after the merger became effective.

8. Under the Board's merger order in Docket No. GM04070721, the Company was to develop a set of service standards and file them with the Board. Then it was to work with the Parties to establish appropriate base-line metrics to measure performance in the areas of safety, reliability, and customer service. Absent a consensus between the Company and the Parties, the Company was to submit its position to the Board. While the Company did develop a set of standards and met with the Parties, no standards or base line metrics were ever finalized or filed with the Board. Thus, the Company could not agree on performance benchmarks, nor remedy certain deficiencies that it was expected to address.

9. Based on the lack of improvement in certain areas and the Company's failure to follow the Board's order, it is recommended that the Company's shareholders be penalized. Considering all of the factors involved, an annual penalty of some amount would be appropriate until such time as the service standards are finalized and any deficiencies relative to accepted industry standards are remedied.

IV. REVENUE REQUIREMENTS AND POLICY ISSUES

Q. WOULD YOU BEGIN BY PUTTING THE COMPANY'S CURRENT FILING INTO PERSPECTIVE BASED ON THE MERGER OF THE COMPANY WITH AGL RESOURCES, INC. ("AGLR")?

A. Prior to the Board's merger order in Docket No. GM04070721, the Company's operation faced several problems. Based on various factors, the rating agencies had downgraded the Company which, in turn, resulted in the Board requiring a focused audit. The subsequent audit performed by the Liberty Consulting Group disclosed deficiencies in the practices of NUI Corporation ("NUI") and its non-regulated subsidiaries. As a result, the Company was required to return $28 million to its ratepayers and pay a $2 million penalty. Additionally, there were identified problems associated with the Company's service levels and various other operating issues as identified in the Liberty audit report. As a result, efforts were undertaken for an ownership change in order to remedy what was characterized as a regrettable episode in New Jersey regulatory history.

In response, a joint petition was filed by NUI and AGLR in July 2004 for a change in ownership and control. In the joint petition, AGLR stated its interest to address the Company's financial condition and to make operational and infrastructure improvements to the utility. In the resulting proceeding, AGLR personnel provided numerous commitments concerning debt restructuring, centralization of several functions through AGLSC and the initiation of "best practices" in the overall utility operation.

Q. IN ITS FILING, HAS THE COMPANY ADDRESSED THE COMPANY'S PROGRESS RELATIVE TO THE VARIOUS COMMITMENTS THAT WERE MADE AT THE TIME OF THE MERGER?

A. In some regards it has, while in others it has not. In her testimony, Ms. Gidley, the president of the Company, does address such issues as AGLR's centralized management structure, various initiatives to enhance customer service, increased capital expenditures, the restructuring of the utility's finances, and the institution of industry leading best practices.

However, there are several aspects of the commitments that are not adequately discussed. The Company has yet to establish formal service standards and its on-going performance has been inadequate in certain areas. The transfer of the Company's call center from Florida to Georgia then to India and now back to New Jersey has resulted in erratic call center performance. Likewise, the Company has continued to use a performance metric (calls answered in 60 seconds) which is well above industry levels (calls answered in 30 seconds). Customer complaints to the Board have also been erratic with high levels in 2006 and 2007.

There also has been a negative impact associated with the transfer of many functions to Atlanta, Georgia. The New Jersey based staff has been reduced dramatically with many functions being directed by Atlanta based personnel. Likewise, contracts that were historically placed with New Jersey firms are now being made with Georgia based firms. While Ms. Gidley discusses the creation of 50 new jobs in the state because of the new customer call center, she does not discuss the Company's overall employment in the state since the merger.

Q. ARE THERE ANY OTHER SIGNIFICANT ISSUES THAT WERE NOT ADDRESSED IN MS. GIDLEY'S TESTIMONY?

A. Perhaps the most relevant factor, the level of rates that will be paid by New Jersey ratepayers, was not discussed in her testimony. There was an implicit commitment made in the merger case to realize cost reductions which would mitigate rate increases in the future. The refinancing of the NUI debt with reductions in interest expense, the savings associated with centralized services performed by AGLSC and the institution of best practices were all envisioned to bring about acquisition related synergies. Indeed, in testimony submitted by AGLR in the merger case there were references to AGLR's retention of future synergies (Madden Rebuttal Testimony, p.7). Accordingly, with the Company transitioning from NUI to AGLR ownership, there was an implicit belief that operations would improve and rates would be stabilized.

While a $24.8 million or 4.7% rate increase may not appear excessive, it certainly is not compatible with the expectation that AGLR ownership would benefit ratepayers. To put this amount into perspective, it should be noted that AGLR, through its Sequent Energy Management affiliate, has realized millions of dollars in gross margins through its asset management agreement with the Company and only a low portion of these margins were credited back to the New Jersey operation. These gross margins were shared with the Company's ratepayers receiving the first $4.0 million per year. **[Begin Confidential information:** [redacted]. **End Confidential information].** While this was a windfall level of gross margins, the Company's affiliate, Sequent Energy Management never made any effort to equitably share the windfall.

- Revenue Decoupling Mechanism

Q. IN MR. YARDLEY'S TESTIMONY HE PROPOSES A REVENUE DECOUPLING MECHANISM THAT IS QUITE SIMILAR TO PILOT PROGRAMS THAT ARE CURRENTLY IN EFFECT AT NEW JERSEY

NATURAL GAS AND SOUTH JERSEY GAS. WOULD YOU PLEASE COMMENT ON HIS PROPOSAL AND THE ADOPTION OF SUCH A PROGRAM AT THIS TIME?

A. Mr. Yardley proposes a EUA tariff rider for ETG which is quite similar to the Conservation Incentive Program ("CIP") mechanism that is utilized in those two pilot programs. These programs were to end in October 2009 unless they are extended by the Board, and there is a pending request before the Board to extend them until October 2010.

While Mr. Kalcic discusses the proposed mechanics of the proposed EUA, there are several associated policy issues that will be addressed here. The first involves the fact that while such mechanisms are being supported as a matter of public policy, they may have the effect of negating certain aspects of the regulatory formula.

Under the accepted regulatory framework, a utility is provided the opportunity to earn a fair rate of return. There are no guarantees and indeed the presumption has been that once a utility is provided its fair rate of return, it will hold off earnings attrition through efficient operation and cost control.

In the case of revenue decoupling, an additional factor is being introduced into the formula. In order to promote energy conservation, risk is being shifted from stockholders to the utilities' ratepayers. Therefore, at a minimum, the utility's authorized rate of return should reflect the lower risk for the operation. A decoupling rider furthers the interests of shareholders who already benefit from manufactured gas plant remediation and pipeline integrity riders along with incentive sharing mechanisms.

As discussed in a paper by the Electricity Consumers Resource Council ("ELCON") (www.elcon.org/Documents/Publications/3-1RevenueDecoupling), revenue decoupling makes a utility "indifferent to the impact of sales levels" or whether the sales vary because of "changing economic conditions, weather, or new technologies." Under a decoupling mechanism, ELCON further notes that, "conservation efforts are rewarded with higher future rates, while excessive consumption paradoxically produces bill credits." Indeed, decoupling mechanisms "actually undermine incentives for customers to invest in more efficient appliances and equipment because the reward for reducing consumption is higher rates in the future." And finally, during economic slowdowns such as we have now, decoupling "neutralizes the financial incentive to attract new commercial and industrial business - and new job opportunities - to the utility's franchise area."

Q. ARE THERE ANY OTHER CONSIDERATIONS THAT SHOULD BE TAKEN INTO ACCOUNT WHEN EVALUATING DECOUPLING MECHANISMS?

A. Yes. It should be remembered that the decoupling pilot program in New Jersey is scheduled to end in October of this year, although there is a pending request before the Board to extend the program until October 2010. It is assumed that, based on the pilot, both NJNG and South Jersey, as well as other parties, may wish to modify the existing CIP mechanism. Based on such potential changes, it would be beneficial for the Board to establish specific proceedings to evaluate gas decoupling mechanisms. This would ensure that lessons from the pilot programs would be incorporated and that there would be specific mechanisms for gas utilities. Both NJNG's and SJG's CIPs incorporate savings and rate of return criteria, while ETG's proposal does not. Likewise, the Board might want to place limits on which parties should bear the economic impact of conservation. Based on various considerations, perhaps the decoupling impact could be shared by stockholders and ratepayers rather than implicitly placing all economic consequences on the very ratepayers that will be making conservation work.

The gas distribution utilities face relatively unique demand considerations. In many instances, gas utilization is seen as one of the more environmentally desirable energy alternatives. Thus, the gas utilities have and will experience growth as electric generators, commercial and industrial consumers as well as residential customers switch to gas vs. other fuels. This is all the more relevant since the majority of gas supplies are available domestically, unlike oil which is heavily imported.

Therefore, it is recommended that any decision on the Company's initiation of a decoupling mechanism be deferred and addressed in a separate gas utility proceeding. This would give all stakeholders the opportunity to have input into a very complex modification to the checks and balances of the current regulatory framework. My local oil delivery company has a goal that is very applicable to the gas distribution utilities. Namely, the goal to sell less oil to more people. In a gas related decoupling proceeding, perhaps a similar conceptual goal could be sought.

- <u>Accounting Related Issues</u>

Q. BASED ON YOUR REVIEW OF THE FILING, ARE THERE ANY ACCOUNTING RELATED ISSUES WHICH YOU BELIEVE SHOULD BE DISCUSSED?

A. Yes. There are several changes that I would recommend that the Board consider. The first involves the charges associated with the Company's relocation of its call center to Union, New Jersey. The Company is treating $740,386 of transition costs associated with the relocation as a one-time expense subject to amortization over five years. In my opinion, such transition expenses should not be charged to New Jersey ratepayers.

Presumably, the Company's ratepayers have already paid costs associated with the transition of the call center from Florida to Georgia, and from Georgia to India. Accordingly, to seek recovery of costs for a third transition is unwarranted.

Various parties objected initially to the outsourcing of the call center to India, including Rate Counsel, and despite such opposition, the Company went forward with the move. As Ms. Gidley now notes in her testimony, the Company's "customer base presents certain unique challenges for our call center operations." Despite such unique challenges and the fact that, to my knowledge, no other United States utility had at that time done such outsourcing to India, the Company proceeded to implement an unproven call center option.

As a result, the Company's ratepayers have already paid for call center relocations and have had to endure inferior service and may have to do so prospectively as the New Jersey call center is established. Additionally, it has been disclosed that about 85% of the one-time transition costs are associated with potential contract penalties and legal fees stemming from its termination of the Company's contractor in India (Company Response RCR-A-171). Given such considerations, it is AGLR stockholders and not the Company's ratepayers that should fund such service remediation efforts.

Q. YOU STATED THAT YOU HAD SEVERAL RECOMMENDED ACCOUNTING CHANGES. WOULD YOU PLEASE DISCUSS YOUR NEXT RECOMMENDED CHANGE?

A. The second accounting change involves the recovery of expenses associated with the Company's MGP remediation efforts. In its filing the Company has proposed the recovery of its internal remediation labor costs in its base rates. The basis for this appears to be a request by the Board's audit staff. Such internal MGP labor costs involve about $65,000 per year.

While this is a relatively small expenditure amount, it seems illogical to separate internal labor costs from all of the other remediation expenses. At the current time there are annual MGP remediation reviews that encompass all remediation activities with analysis of associated invoices and an evaluation of related activities. To segregate internal labor costs from such reviews is unnecessary and would subject such costs to limited oversight in base rate proceedings. The Board has authorized the RAC clause for MGP cost recoveries, and that mechanism should be all inclusive.

Q. DO YOU HAVE ANY ADDITIONAL ACCOUNTING CHANGES THAT THE BOARD SHOULD CONSIDER?

A. Yes. There is one last change related to conservation program expenses. The Company has requested that $940,000 of such costs be included in base rates. However, it is my understanding that all other conservation related expenses are recovered through the Regional Greenhouse Gas Initiative ("RGGI") tariff. In its response to request RCR-A-187, the Company acknowledged it would be possible to obtain rate recovery through its next RGGI filing if no base rate recovery was obtained in this case.

Since conservation expenses are variable, it would seem beneficial to make provisions for their recovery under the RGGI tariff based on actual expenditures. By recovering such expenses through RGGI, the cost would be recovered annually based on actual incurred expenses rather than at a fixed level. Such a procedure would protect both the Company and its ratepayers.

- Affiliate and Management Audit Issues

Q. WOULD YOU PLEASE DESCRIBE THE AUDITS OF THE COMPANY THAT ARE CURRENTLY IN PROCESS?

A. The Board in Docket No. GA07100795 issued a request for proposal ("RFP") solicitation for affiliated transactions and management audits for the Company. The initial RFP specified that these two audits would be performed in two concurrent phases that were to be completed within 280 days from the date of any contract award.

These audits were seen as an appropriate initiative given the terms and conditions of the merger stipulation and the anticipated filing of this base case by the Company. The two prior audits concerning Competitive Service Offerings and Affiliate Standards that were performed in 2000 and 2003 were one of the factors that gave rise to the petition for a change in ownership and control in Docket No. GM04070721.

Q. WAS IT ANTICIPATED THAT THE RESULTS OF THESE AUDITS WOULD BE AVAILABLE BEFORE THE CURRENT RATE CASE WAS RESOLVED?

A. Yes, it was. The availability of such audit reports would allow the parties to determine whether AGLR had satisfied many of the conditions of the merger. It should be remembered that various management and control issues as well as affiliate transactions played a large role in the need for an ownership change.

Given that these audits have not been completed and that no other comprehensive operations or affiliate reviews have been conducted since the merger, it is not possible to determine whether certain elements of the Company's revenue requirements are just and reasonable. This concern is all the more relevant because AGLR itself has had problems with its own affiliate transactions and has been required to provide credits based on various regulatory orders.

Q. GIVEN THE CURRENT STATUS OF THE AUDITS, IS THERE ANYTHING THAT THE BOARD SHOULD CONSIDER RELATIVE TO ANY RATE AUTHORIZATIONS MADE IN THIS PROCEEDING?

A. Yes. It is recommended that any Board order in this proceeding be made subject to modifications if indicated. Thus, any Board order would stand unless challenged by a party on the basis of findings and recommendations contained in the anticipated final audit reports. In effect, the revenue requirement in this proceeding assumes that in many areas the Company has fulfilled its merger requirements. If subsequently there is evidence that it has not, then there should be a procedural mechanism for parties to challenge the level of revenue requirements and/or to request that penalties be imposed on the Company.

- Service Levels and Penalty

Q. WOULD YOU PLEASE DISCUSS HOW SERVICE STANDARDS WERE INVOLVED IN THE MERGER PROCEEDING AND WHY THEY WERE CONSIDERED TO BE CRITICAL?

A. Prior to the merger, the Company had problems with its financial condition and various affiliate interest abuses, and its overall customer service levels had deteriorated. Thus, there was an inherent mandate for any potential acquirer to stabilize the Company's finances, its governance, and its service to its ratepayers. AGLR, the ultimate purchaser, was specifically authorized by the Board to make necessary changes, and it stated that, "while no specific commitments have been made, AGLR is confident that improvements can be made in customer service as well as the safety and reliability records at NUI." (Response NJLEUC-AGLR/NUI-96 in Docket No. GM04070721).

Q. BY LOOKING AT VARIOUS PERFORMANCE MEASURES THAT HAVE BEEN COMPILED BY THE COMPANY BOTH BEFORE AND AFTER THE

MERGER, CAN ONE IDENTIFY SPECIFIC RESULTS FOR CERTAIN SERVICE AREAS?

A. Yes. There is sufficient data to track the Company's performance in several areas. The schedules attached to this testimony provide data on several service metrics which are addressed in Ms. Callaghan's direct testimony where she explains the metrics and recommends what she and I believe are reasonable standards commensurate with standard service levels in the utility industry. The basic metrics involve field operations, meter reading and billing, call center operation, and overall service. Each of the performance measures in these areas is important because they all reflect interaction between the Company and its customers. Whether it involves call center operations, billings, or field personnel, these are the components that determine customer satisfaction.

Q. WOULD YOU BEGIN BY DISCUSSING THE COMPANY'S PERFORMANCE IN FIELD OPERATIONS?

A. Yes. The first area reviewed involved the Company's service appointments met or appointment attainment. This activity includes appointments for disconnects and reconnects, billing investigations, and starting and final meter readings. The gas industry typically utilizes a standard of 95% attainment or higher. As shown on page 1 of Schedule 1, the Company, since the merger, has been close to the standard for all years but 2007. During that year, there were seven months when the percentage was 90% or lower. However, whatever the issue that year, the Company returned to acceptable performance by year end.

The second measure of field operations involves perhaps the most critical metric in the gas industry. This measures response time for customer gas leak calls between the time the call is received until qualified utility personnel arrive at the customer's premise. The metric is normally a 95% response within 30 to 60 minutes.

On page 2 of Schedule 1, the Company's data is shown by year for the period 2005-2008 using the Company's 45 minutes requirement. As a general matter, none of the years show an acceptable level of leak response when compared against the industry benchmark of 95%. While there was improvement from 2005 to 2006, the response levels fell thereafter with leak response percentages at 90% or less in 16 out of the 24 months. Given the importance of this measure, the Company should be maintaining at least a 95% level of compliance.

Q. TURNING TO THE SECOND AREA OF SERVICE METRICS INVOLVING METER READING AND BILLING, HAS THERE BEEN IMPROVED PERFORMANCE?

A. Yes. Referring to Schedule 2, the Company's percentage of actual meter reads has increased continuously since 2003. From averages below 45% in 2002-2003 the

Company achieved a level of 95% in 2008, which is the typical industry benchmark. This improvement is presumably linked to the Company achieving a high penetration percentage for its Automated Meter Reading ("AMR") program.

As for billing accuracy, the Company did not provide any data which showed re-billed levels. However, the roll out of the AMR program probably had some favorable impact in reducing billing errors and the need for re-bills.

Q. WOULD YOU NOW DISCUSS THE COMPANY'S PERFORMANCE RELATIVE TO ITS CALL CENTER OPERATIONS?

A. In order to analyze the Company's call center, three service metrics were evaluated. The first involves the Company's average call answering time, which reflects the average time it takes for a customer to reach a customer representative. Based on the data shown on page 1 of Schedule 3, the Company went from a 25 second average in 2002 to a 282 second average in 2004. Since that time there have been mixed results with the best results being achieved in the last half of 2008.

In addition to monitoring call answering times, the Company tracked calls answered within 60 seconds. This is in contrast to a typical industry metric which records calls answered in 30 seconds. A comparison between the 30 and 60 second metrics data for 2002-2004 is provided on page 2 of Schedule 3. To put this comparative data into perspective, the industry standard is 80% of calls being answered in 30 seconds. As shown by the data, historically the Company was far from meeting the industry standard, and did not meet an 80% standard even with the higher 60 second metric during 2003 and 2004. Simply stated, these statistics show that, between 2002 and 2004, the Company call center operation was deficient.

Q. WHAT HAS BEEN THE COMPANY'S PERFORMANCE SINCE THE MERGER?

A. The third page of Schedule 3 shows the applicable data. It should be noted that this data is based on the higher 60 second response interval. As is apparent, even with this less stringent standard, the Company only achieved 80% or higher compliance beginning in May 2007.

At the bottom of the schedule yearly data is shown for the same period based on actual levels using a 60 second interval and as extrapolated for a 30 second interval. As the data shows, on an annual basis the Company never achieved 80% compliance under a 30 second standard. Thus, while there has been steady improvement since 2004, the Company has yet to achieve performance levels comparable to the industry benchmark.

Q. WHAT OTHER METRICS DID YOU ANALYZE TO ASSESS THE COMPANY'S CALL CENTER OPERATION?

A. The last measure reviewed involved the number of calls that were terminated before reaching a customer service representative. This service metric is perhaps the most informative because it is effectively measuring customer satisfaction. When a customer terminates a call, it is a very good indication that the customer was dissatisfied with the Company's ability to meet the customer's expectation.

While the Company was requested in discovery to provide data on all of its performance metrics, no data was included for the Company's abandoned call percentage ("APC"). However, previously in various submissions by the Company, APC data had been provided for the 2002 through 2004 period (see Schedule 3, page 4). This data provided the number of customers that abandoned their calls before reaching a customer service representative. While this data is not expressed as a percentage of calls tendered, which is the typical industry metric, it does show relative performance. During 2002 and 2003 the average of monthly calls that were abandoned were between 1,400 and 2,700 per month. In contrast, for the first nine months of 2004, such abandoned calls increased to an average of 17,400 per month.

As recommended in Ms. Callaghan's testimony, this should be an on-going metric for the Company, and it should be reported as the percentage of calls that were terminated (or abandoned). Prospectively, the standard for this service metric should be a 5% or lower percentage of abandoned calls.

Q. YOUR LAST IDENTIFIED PERFORMANCE AREA WAS OVERALL SERVICE. CAN YOU EXPLAIN HOW THIS IS MEASURED AND WHAT HAS BEEN THE TREND FOR THE METRIC?

A. The last measure involves the number of customer complaints. This is measured by complaints made to the BPU which does not include complaints that were made to the Company directly. One can assume, that at least in many cases, complaints to the BPU reflect instances where the customer contacted the Company and could not resolve the associated problem.

The number of complaints to the BPU are shown by month on page 1 of Schedule 4. There are also averages shown at the bottom of the schedule for the 2001-2003 and the 2005-2007 periods reflecting performance both before and after the merger. Based on this data, there was no material improvement during the post merger period.

In order to put these customer complaint levels into context, the level of complaints are shown on a complaints per 1,000 customers basis. As a general guideline, the industry standard is less than 1 complaint per year per 1,000 customers. On page 2 of Schedule 4 this data is shown for the Company between 2001 and 2008. As indicated, while the last four years had better performance (lower complaints) than in 2004, the level has still not met the accepted industry benchmark.

Q. BASED ON YOUR REVIEW, PLEASE DISCUSS THE SERVICE METRICS, THE COMPANY'S RELATIVE PERFORMANCE, AND ACTIONS THAT THE BOARD SHOULD CONSIDER.

A. As an initial matter, the Board needs to require that the Company complete and finalize appropriate service metrics. This will involve several steps. The metrics themselves need to be identified and benchmark or baseline levels need to be established. Based on the data provided by the Company, there are a few areas where additional metrics are necessary. For example, in the area of field operations, the leak response data should be augmented with exception reporting. In instances where the established metric is not met, the Company should report the actual response time and there should be a discussion of why the 45 minute response time was not met. While the Company's metric requires a response in 45 minutes 95% of the time, there is no way of evaluating the nature of responses that exceed the time interval. While 5 or 10 minutes may be acceptable, if the delays are excessive, then such performance needs to be addressed. Exception reporting allows evaluation and appropriate remedial action as required.

A second area that should be incorporated into the metrics would involve data on billing accuracy. Typically, utilities monitor the number of rebills as a percentage of total billing. This is an industry metric with a benchmark of less than 20 rebills per 1,000 customers. And finally, a metric should be developed for the Company's abandoned call percentage. The Company apparently has compiled such data in the past, but such information has not been provided in recent years.

Assuming that these additional metrics and their benchmarks were required, the Board then needs to determine whether there is a need for a penalty associated with the Company's performance since the merger. Since the Company has been under new ownership for almost five years, it is reasonable to conclude that certain areas of improvement in service have not been accomplished and that the Company has not satisfied certain Board requirements established as part of the merger approval. Accordingly, it is recommended that an annual penalty of $1.0 million be imposed until such time as the Company's service measures are finalized and any deficiencies relative to accepted industry standards are remedied. This penalty is appropriate and can be avoided by the Company in the future by fulfilling the Board's requirements and bringing the Company service up to industry levels.

As a final observation, it should be recognized that utility service measures have their nexus to utility regulation as a result of merger activity. Too frequently, acquiring utilities, in their efforts to consolidate operations and potentially address associated acquisition premiums paid as part of the merger, have reduced staffing and operating expenses. In certain cases, overall performance has suffered and regulatory commissions have responded by imposing service standards. As such, the specification of service metrics and the filing of service data periodically has become a necessary adjunct to the merger process. The Company, therefore, should accept the need for such monitoring, and the Board should enforce monitoring as required.

Q. MR. LELASH, DOES THIS CONCLUDE YOUR DIRECT TESTIMONY IN THIS MATTER?

A. Yes, it does at this time.

SUPPORTING SCHEDULES

Elizabethtown Gas Company
Appointment Attainment %

	2005	2006	2007	2008
January	94%	99%	95%	93%
February	90	98	83	96
March	92	97	87	95
April	93	97	88	96
May	92	98	89	95
June	96	99	93	96
July	94	99	92	93
August	98	98	90	93
September	97	99	90	95
October	92	98	93	93
November	96	97	90	93
December	97	99	95	93
Averages	94%	98%	90%	94%

SOURCE: Company Response RCR-CSV-12.1.

Elizabethtown Gas Company
45 Minutes Leak Response %

	2005	2006	2007	2008
January	79%	93%	91%	90%
February	82	93	85	89
March	83	93	88	90
April	85	95	84	91
May	85	93	91	92
June	85	94	92	92
July	85	93	89	91
August	86	94	90	91
September	85	91	90	88
October	75	89	89	87
November	84	92	86	88
December	89	93	90	87
Averages	84%	93%	89%	90%

SOURCE: Company Response RCR-CSV-12.1.

Elizabethtown Gas Company
Percent Actual Meter Read

	2002	2003	2004	2005	2006	2007	2008
January	47%	44%	41%	65%	73%	89%	95%
February	44	41	43	68	72	91	95
March	36	44	44	68	78	90	92
April	38	38	45	70	73	90	92
May	45	46	46	58	76	91	96
June	33	42	46	53	78	91	94
July	48	44	44	55	79	89	93
August	44	42	44	58	80	91	96
September	40	38	48	69	83	92	96
October	40	48	–	70	82	90	97
November	39	42	–	71	84	91	92
December	38	40	49	72	86	93	96
Averages	41%	42%	45%	65%	79%	91%	95%

SOURCES: Company Response RCR-CSV-12.1 and Company Letter, May 23, 2005.

Elizabethtown Gas Company
Call Answering Time - Seconds

	2002	2003	2004	2005	2006	2007	2008
January	40	40	204	190	76	190	161
February	32	70	347	179	74	332	79
March	26	60	519	193	64	169	36
April	33	30	691	54	43	110	33
May	32	40	299	41	53	41	38
June	21	31	286	54	52	52	28
July	21	31	475	65	56	36	11
August	24	26	279	282	43	40	13
September	8	61	126	248	60	33	14
October	14	104	41	210	68	46	13
November	19	168	61	49	73	91	8
December	24	123	51	18	68	60	10
Averages	25	65	282	132	61	100	37

SOURCES: Company Response RCR-CSV-12.1 and Company Letter, May 23, 2005.

Elizabethtown Gas Company
60 vs. 30 Second Call Response %

	Response in 60 Seconds			Response in 30 Seconds		
	2002	2003	2004	2002	2003	2004
January	80	81	44	51	50	39
February	82	66	28	52	32	24
March	87	73	15	48	48	13
April	84	87	8	33	71	7
May	87	83	40	43	73	36
June	91	84	43	60	73	38
July	91	86	18	59	72	14
August	88	89	41	36	78	33
September	98	77	58	34	68	51
October	93	62	85	34	55	81
November	90	50	75	33	43	70
December	87	59	80	34	53	69
Averages	88	75	45	43	60	40

SOURCE: Company Call Center Response Information.

Elizabethtown Gas Company
60 Second Call Response %

	2002	2003	2004	2005	2006	2007	2008
January	80	81	44	49	67	47	53
February	82	66	28	52	66	39	71
March	87	73	15	54	72	62	84
April	84	87	8	75	77	73	85
May	87	83	40	77	74	82	84
June	91	84	43	69	69	80	88
July	91	86	18	65	69	87	94
August	88	89	41	26	75	83	93
September	98	77	58	36	67	87	94
October	93	62	85	40	63	82	93
November	90	50	75	78	53	65	96
December	87	59	80	91	63	77	95
Averages 60	88	75	45	59	68	72	86
Averages 30	43	60	40	41	47	50	59

SOURCES: Company Response RCR-CSV-12.1 and Company Letter, May 23, 2005.

Elizabethtown Gas Company
Abandoned Calls (000's)

	2002	2003	2004	2005	2006	2007	2008
January	2.5	1.7	13.5				
February	2.1	2.8	19.4				
March	1.3	2.8	24.1				
April	2.1	1.1	29.3				
May	1.9	1.8	12.5				
June	1.8	1.1	16.5				
July	1.2	1.3	19.5				
August	1.4	1.0	12.4				
September	0.5	2.6	9.6				
October	0.6	4.4					
November	0.6	6.5					
December	0.8	5.1					
Averages	1.4	2.7	17.4				

SOURCES: Company Letter, May 23, 2005.

Elizabethtown Gas Company
Customer BPU Complaints

	2001	2002	2003	2004	2005	2006	2007
January	65	56	86	160	94	91	77
February	51	49	83	156	80	71	111
March	80	46	57	149	90	125	173
April	89	56	91	232	71	89	125
May	83	54	80	150	77	104	111
June	72	48	70	113	68	79	65
July	86	42	83	104	70	47	61
August	75	47	33	119	89	58	66
September	54	38	100	92	86	64	62
October	63	101	179	123	147	100	57
November	63	68	93	92	91	83	67
December	46	79	137	124	86	88	38
Totals	827	684	1,092	1,614	1,049	999	1,013
Averages		868		-		1,020	

SOURCES: Company Response RCR-CSV-12.1 and Company Letter, May 23, 2005.

Elizabethtown Gas Company
Complaints Per 1,000 Customers

Year	Complaints	Customers	Per 1,000
2001	827	255,700	3.23
2002	684	258,600	2.65
2003	1,092	260,900	4.19
2004	1,656	263,200	6.29
2005	1,050	266,100	3.95
2006	999	268,900	3.72
2007	1,013	271,800	3.73
2008	810	274,700	2.95

Note: Customer levels are approximate annual averages.

SOURCE: Annual Performance Reports, Company Letter, May 23, 2005 and Schedule 4, page 1.

APPENDIX: PRIOR R.W. LELASH TESTIMONIES

R. W. LELASH'S REGULATORY TESTIMONIES
(2003 to Present)

262. Rhode Island, New England Gas Company (Docket No. 3476) Service Quality Surrebuttal Testimony for the Division of Public Utilities (February, 2003).

263. Pennsylvania, Philadelphia Gas Works (Docket No. R-00038173) Gas Procurement and Policy Testimony for the Pennsylvania Office of Consumer Advocate (April, 2003).

264. New Jersey, Elizabethtown Gas Company (Docket No. GA02020099) Comments Concerning Affiliate Audit for the New Jersey Division of the Ratepayer Advocate (June, 2003).

265. Maine, Northern Utilities (Docket No. 2002-140) Management Audit and Service Quality Report for the Maine Public Utilities Commission (June, 2003).

266. New Jersey, Public Service Electric & Gas Company (Docket No. GR03050400) Pipeline Refund Allocation Testimony for the New Jersey Division of the Ratepayer Advocate (August, 2003).

267. Ohio, Vectren Energy Delivery of Ohio (Case No. 02-220-GA-GCR) Gas Procurement and Policy Testimony for the Ohio Consumers' Counsel (November, 2003).

268. Delaware, Delmarva Power & Light Company (Docket No. 03-378F) Evaluation of Gas Procurement and Price Hedging Testimony for the Delaware Public Service Commission (February, 2004).

269. Pennsylvania, Philadelphia Gas Works (Docket Nos. R-00049157 and P-00042090) Purchased Gas Cost Testimony for the Pennsylvania Office of Consumer Advocate (May, 2004)

270. Pennsylvania, Philadelphia Gas Works (Docket Nos. R-00049157 and P-00042090) Purchased Gas Cost Rebuttal Testimony for the Pennsylvania Office of Consumer Advocate (May, 2004)

271. Delaware, Chesapeake Utilities Corporation (Docket No. 02-287F) Gas Supply Plan Review for Chesapeake Utilities and the Delaware Public Service Commission (July, 2004).

272. Georgia, Atmos Energy Corporation (Docket No. 18509-U) Procurement and Capacity Plan Testimony for the Georgia Public Service Commission (August, 2004).

273. Georgia, Atlanta Gas Light Company (Docket Nos. 18437-U and 8516-U) Procurement and Capacity Plan Testimony for the Georgia Public Service Commission (August, 2004).

274. New Jersey, NUI Utilities and AGL Resources (Docket No. GM04070721) Terms and Conditions of Merger Testimony for the New Jersey Ratepayer Advocate (September, 2004).

275. Georgia, Atlanta Gas Light Company (Docket No. 18638-U) Business Risk Testimony for the Georgia Public Service Commission (February, 2005).

276. Pennsylvania, Philadelphia Gas Works (Docket No. R-00050264) Purchase Gas Cost Testimony for the Pennsylvania Office of Consumer Advocate (April, 2005).

277. Federal Energy Regulatory Commission, Exelon and Public Service Enterprise Group (Docket No. EC05-43-000) Market Power Testimony by Affidavits for the New Jersey Division of the Ratepayer Advocate (April and May, 2005).

278. Pennsylvania, PECO Energy Company (Docket No. R-00050537) Gas Procurement and Policy Testimony for the Pennsylvania Office of Consumer Advocate (July, 2005).

279. Georgia, Atmos Energy Corporation (Docket No. 20528-U) Gas Supply Plan Testimony for the Georgia Public Service Commission (August, 2005).

280. New Jersey, Public Service Electric & Gas/Exelon (Docket No. EM05020106) Gas Related Merger Testimony for the New Jersey Ratepayer Advocate (November, 2005).

281. New Jersey, Public Service Electric & Gas/Exelon (Docket No. EM05020106) Gas Related Merger Surrebuttal Testimony for the New Jersey Ratepayer Advocate (December, 2005).

282. New Jersey, Pivotal Utilities Holdings (Docket No. GR05040371) Pipeline Replacement Cost Recovery Testimony for the New Jersey Ratepayer Advocate (February, 2006).

283. New Jersey, Public Service Electric & Gas Company (Docket No. GR05050470) Gas Supply Requirements Testimony for the New Jersey Ratepayer Advocate (May, 2006).

284. New Jersey, Public Service Electric & Gas Company (Docket No. GR05100845) Base Rate Gas Policy Testimony for the New Jersey Ratepayer Advocate (June, 2006).

285. Vermont, Vermont Gas Systems (Docket No. 7109/7160) Report on Gas Price Hedging for Vermont Gas Systems (December, 2006).

286. Delaware, Chesapeake Utilities Corporation (Docket No. 06-287F) Report on Gas Price Hedging for Chesapeake Utilities Corporation (March 2007).

287. Delaware, Chesapeake Utilities Corporation (Docket No. 06-287F) Gas Procurement and Policy Testimony for the Delaware Public Service Commission (March, 2007).

288. Pennsylvania, Philadelphia Gas Works (Docket No. R-00061931) Base Rate Case Testimony for the Pennsylvania Office of Consumer Advocate (April, 2007).

289. Pennsylvania, Philadelphia Gas Works (Docket No. R-00072110) Gas Cost Rate Testimony for the Pennsylvania Office of Consumer Advocate (April 2007)

290. Pennsylvania, Philadelphia Gas Works (Docket No. R-00061931) Base Rate Rebuttal Testimony for the Pennsylvania Office of Consumer Advocate (May 2007).

291. Pennsylvania, Philadelphia Gas Works (Docket No. R-0001931) Base Rate Surrebuttal Testimony for the Pennsylvania Office of Consumer Advocate (May 2007).

292. Pennsylvania, PECO Energy Company (Docket No. R-00072331) Gas Procurement and Policy Testimony for the Pennsylvania Office of Consumer Advocate (July, 2007).

293. Georgia, Atlanta Gas Light Company (Docket No. 18437-U) Capacity Supply Plan Testimony for the Georgia Public Service Commission (August, 2007)

294. Delaware, Chesapeake Utilities Corporation (Docket No. 07-186) Gas Policy Testimony for the Delaware Public Service Commission (December, 2007).

295. Delaware, Chesapeake Utilities Corporation (Docket No. 07-246F) Gas Procurement and Policy Testimony for the Delaware Public Service Commission (April, 2008).

296. Pennsylvania, Philadelphia Gas Works (Docket No. R-2008-2021348) Gas Cost Rate Testimony for the Pennsylvania Office of Consumer Advocate (April, 2008).

297. New Jersey, New Jersey Natural Gas Company (Docket No. GR07110889) Base Rate Policy Testimony for the Division of Rate Counsel (April, 2008).

298. Georgia, Atmos Energy Corporation (Docket No. 27168) Gas Supply Plan Testimony for the Georgia Public Service Commission (August, 2008).

299. Pennsylvania, Philadelphia Gas Works (Docket No. R-2008-2073938) Emergency Rate Relief Testimony for the Pennsylvania Office of Consumer Advocate (December, 2008.

300. Delaware, Delmarva Power & Light Company (Docket No. 08-266F) Gas Procurement and Policy Testimony for the Delaware Public Service Commission (February, 2009).

301. Delaware, Chesapeake Utilities Corporation (Docket No. 08-269F) Gas Procurement and Policy Testimony for the Delaware Public Service Commission (March, 2009).

302. Pennsylvania, Philadelphia Gas Works (Docket No. R-2009-2088076) Gas Procurement and Policy Testimony for the Pennsylvania Office of Consumer Advocate (April, 2009).

303. Pennsylvania, PECO Energy Company (Docket No. R-2009-2108705) Gas Procurement and Policy Testimony for the Pennsylvania Office of Consumer Advocate (July, 2009).

304. Delaware, Chesapeake Utilities Corporation (Docket No. 08-269F, Phase II) Gas Policy Testimony for the Delaware Public Service Commission (August, 2009).

305. Georgia, Atmos Energy Corporation (Docket No. 29554) Gas Supply Plan Testimony for the Georgia Public Service Commission (August, 2009).