PUBLIC VERSION

STATE OF NEW JERSEY
OFFICE OF ADMINISTRATIVE LAW
BEFORE THE HONORABLE GAIL M. COOKSON

I/M/O THE PETITION OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY FOR APPROVAL OF AN INCREASE IN ELECTRIC AND GAS RATES AND FOR CHANGES IN THE TARIFFS FOR ELECTRIC AND GAS SERVICE, B.P.U.N.J. NO.16 ELECTRIC AND B.P.U.N.J. NO. 16 GAS, AND FOR CHANGES IN DEPRECIATION RATES, PURSUANT TO N.J.S.A. 48:2-18, N.J.S.A. 48:2-21 AND N.J.S.A. 48:2-21.1 AND FOR OTHER APPROPRIATE RELIEF	))))))))))))	**BPU DOCKET NOS. ER18010029 and GR18010030** **OAL DOCKET NO. PUC 01151-18**

DIRECT TESTIMONY OF EDWARD MCGEE
ON BEHALF OF THE
DIVISION OF RATE COUNSEL

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DIRECT TESTIMONY OF

EDWARD A. McGEE

ON BEHALF OF THE

NEW JERSEY DIVISION OF RATE COUNSEL

BPU DOCKET NO. GR17070776

I. Introduction

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Edward A. McGee. My business address is 5800 One Perkins Place Drive, Suite 5-F, Baton Rouge, Louisiana, 70808.

Q. WOULD YOU PLEASE STATE YOUR OCCUPATION AND CURRENT PLACE OF EMPLOYMENT?

A. I am an Engineering Associate with the Acadian Consulting Group ("ACG"), a research and consulting firm that specializes in the analysis of regulatory, engineering, economic, financial, accounting, statistical, and public policy issues associated with regulated and energy industries. ACG is a Louisiana-registered partnership, formed in 1995, and is located in Baton Rouge, Louisiana.

Q. DO YOU HOLD ANY ACADEMIC DEGREES?

A. Yes. I graduated from the University of Notre Dame with Bachelor and Master Degrees in Chemical Engineering. I also graduated from the University of Chicago with a Master's Degree in Business Administration ("MBA"). Attachment A provides my academic vitae, which includes a listing of my experience as a gas practice consultant and related positions in the energy industry.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have been retained by the New Jersey Division of Rate Counsel ("Rate Counsel") to provide an expert opinion to the Board of Public Utilities ("BPU" or "Board") on a number of engineering, operating, and performance issues associated with the base rate proposal filed by Public Service Gas & Electric Company ("PSE&G" or "the Company") on January 12, 2018. My testimony will particularly focus on the engineering and operating issues. Dr. David E. Dismukes, a Consulting Economist for ACG, will address the specific economic and regulatory issues associated with the Company's proposals.

Q. HAVE YOU PREPARED ANY SCHEDULES IN SUPPORT OF YOUR RECOMMENDATIONS?

A. Yes. I have prepared three (3) schedules in support of my direct testimony that were prepared by me or under my direct supervision.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. My testimony is organized into the following sections:

- Section II: Summary of Findings and Recommendations
- Section III: Evaluation of Company Performance in Operating Areas
- Section IV: Continuing Installation of "Most-Risky" Asset
- Section V: Potential Delay in Completion of Large Replacement Expense
- Section VI: Status of Major Replacement Programs
- Section VII: Pipe-Sizing for the Major Replacement Programs
- Section VIII: Leak Reduction Performance and Improved Metrics
- Section IX: Conclusions and Recommendations

II. <u>Summary of Findings and Recommendations</u>

A) Findings:

1) The Company's performance measure of "Leak Damages per 1,000 Locate Requests" has gone from being better than two groups of comparable gas companies in 2009, to being worse than both groups in 2016.
2) Plastic service lines suffering Excavation Damage have risen from being the Company's fourth-highest asset risk in 2014, to becoming the Company's highest-risk asset in 2017.
3) It is doubtful that one of the Company's current construction projects (the Crown Central Transmission Pipeline Replacement Project) will be in-service by the end of the Post Test period (December 2018).
4) The Company's reliance on one of its Gas Design Standard Utilization Pressure ("UP") replacement policies appears to be unnecessarily expensive.
5) The leak-reduction stipulations in the Energy Strong, GSMP, and earlier programs resulted in leak reductions for leaks that were discovered in only one year. A new leak reduction metric was established after the Energy Strong program, which better controls the number of outstanding leaks at the end of each future year.

B) Recommendations:

1) The Company is no longer keeping up with other comparable gas utilities in one of its key performance measures: Leak Damages per 1,000 Locates. The Company is no longer attaining its target of being in the top quartile of comparable gas utilities; and has recently fallen below the median of these utilities. The Company should dedicate more resources and develop additional programs toward stemming the rise in this operating performance statistic.

2) The Company's plastic service lines that are subject to excavation damage have now risen to its most-risky asset. The Company should dedicate more resources toward stemming the hazardous risks to the Public of excavation damage to these service lines. An example of a step that might be taken includes sponsorship of an industry research program that would analyze the ways to best protect the type of material used in its plastic services.

3) Since it is doubtful that the Company's Crown Central Transmission Pipeline Replacement Project will be in service by December, 2018, we recommend that its estimated cost of $19.9 million be removed from inclusion in the list of capital expenditures scheduled for the Post Test Year.

4) Since UP systems are being replaced in significant numbers in recent years, one of the Company's Gas Design Standards that requires a minimum mains replacement size of four-inch-diameter appears to be too conservative. We recommend that when sizing replacement piping for smaller-diameter UP mains, the Company should run flow/pressure simulations of projected gas demand in these mains for the near-future – instead of following its current Gas Design Standard. In similar prior cases, Rate Counsel has taken the position that oversizing of pipes is the Company's prerogative, but the extra costs would not be permitted to be passed on to ratepayers.

I would also recommend that the Company review all of its Gas Design Standards at this time in order to determine if there are other minimum-size installation Standards that should also be updated, and modify them as necessary. Further, I would recommend that the Company review the sizing of all piping in the Energy Strong and GSMP programs to determine which installations – if any – should be disallowed in this Rate Case due to minimum-size Standards, and notify all parties of the amounts that should be disallowed.

5) Since the leak-reduction stipulations in the Energy Strong, GSMP, and earlier programs resulted in leak reductions for leaks that were discovered in only one year, a new formulation has been introduced for the very recent GSMP-II program that we recommend for use in future programs. The new formulation will continuously reduce all outstanding leaks throughout each year of the program.

III. <u>Evaluation of Company Performance in Operating Areas</u>

Q. HOW DOES THE COMPANY MEASURE ITS OWN PERFORMANCE IN OPERATING AREAS?

A. The Company relies on a number of operating performance statistics to regularly measure the effectiveness of its performance in various operating areas. Effectiveness is evaluated through comparison against recent annual trends, through comparisons against other gas companies, or against targets developed in conjunction with the NJ BPU. These include such measures as:

- Number of Leaks Repaired or Eliminated
- Number of Excavation Damages
- Number of Leaks per Mile
- Number of Breaks per Mile

Q. HAVE YOU REVIEWED THE COMPANY'S PERFORMANCE IN ANY OPERATING AREAS?

A. Yes. I have reviewed the Company's operating performance in the area of excavation damage, particularly as it involves hazardous (Class 1) leaks, and as it affects gas service lines.

Q. HOW SERIOUS IS EXCAVATION DAMAGE TO PSE&G?

A. Excavation Damage to piping at PSE&G is serious since excavation damage has a higher proportion of leaks that are classified as hazardous leaks than any other leak cause (see Schedule EAM-01). This graph indicates that almost 100% of the leaks that the Company repaired in 2017 that were attributable to excavation damage were considered to be hazardous. Each of the seven other causes of leaks had a hazardous percentage less than 40 percent.

Q. COULD YOU DESCRIBE THE COMPANY'S PERFORMANCE MEASURE IN THE AREA OF EXCAVATION DAMAGE?

A. Yes. The performance measure of "Leak Damages per 1,000 Locate Requests" is used by the Company to assess the effectiveness of its Damage Prevention Program.[1] Locate requests are the number of times an excavator calls into the One-Call Center requesting someone to come to his location and mark where the underground piping lies.

Q. COULD YOU DESCRIBE THE COMPANY'S DAMAGE PREVENTION PROGRAM?

A. Yes. The State of New Jersey requires that the location of underground utility installations be identified and marked out prior to work that involves any digging operation. Activities covered by this requirement include excavations or trenching, blasting, installation of tents, sign posts, or fence posts, and removing or planting of trees.[2] In this Program, excavators are required to "Call Before You Dig". When a call is placed to 811 or 1-800-272-1000, it is automatically connected to the One Call center, which collects information about the digging project. The center then provides the information to PSE&G, who sends representatives to mark the locations of underground lines in the immediate vicinity of the planned work location with flags, paint or both.[3]

[1] Company Response to RCR-G-POL-0005.
[2] Cardenas Direct Testimony, page 46.
[3] https://nj.pseg.com/newsroom/newsarticle7

Q. HOW WELL HAS THE COMPANY BEEN PERFORMING IN TERMS OF ITS DAMAGE PREVENTION PERFORMANCE MEASURE OF LEAK DAMAGES PER 1,000 LOCATES?

A. The Company's performance statistic showing the number of Leak Damages per 1,000 Locate Requests has been rising over time. This is shown in Schedule EAM-02, where the Company's performance is compared to the performance of two groupings (top-quarter and top-half) of comparable gas utilities selected by the Company as its benchmark utilities.

Q. WHAT RECENT TRENDS ARE SHOWN IN SCHEDULE EAM-02?

A. Schedule EAM-02 is a benchmark graph showing recent performance for PSE&G, as well as the performance of two groupings of comparable utilities. This graph indicates that:

- The Company's excavation damage rate in 2009 was below (better than) the rate of its top-quartile benchmark companies and was significantly below the median of all benchmark gas companies. However, the Company's rate of damages surpassed (became worse than) the rate of its top-quartile benchmark group of comparable utilities after 2012; and even surpassed the rate of the median group of comparable utilities after 2014.
- Excavation damage rates for the Company have been higher in all subsequent years than they were in 2012.
- The Company's excavation damage rate rose sharply in 2013 and remained higher through 2016.

Q. HAS THE COMPANY EXPLAINED WHICH ASSETS ACCOUNT FOR THE RECENT INCREASE IN THEIR EXCAVATION DAMAGE RATES?

A. Yes. The Company attributes increases in excavation damage rates to service lines and service stubs, as explained in a Company discovery response: "Damages to gas services and gas service stubs in these areas [construction occurring near legacy facilities] are the leading contributors of the increase in damage rate."[4]

Q. ARE THERE PHYSICAL REASONS THAT EXCAVATION DAMAGE TO SERVICE LINES IS MORE DANGEROUS THAN DAMAGE TO OTHER COMPANY ASSETS?

A. Yes. Damage to gas service lines is more serious than damage to other Company piping since:

1) Pipe walls on service lines are thinner than walls on other piping.
2) Service line piping is closer to buildings.
3) Ages and material types of service lines are less well known.
4) There are more leaks annually on service lines than on other piping.
5) There are more hazardous leaks on service lines than on other piping.
6) The use of plastic materials for service lines has resulted in services less resistant to many types of damages.

Q. WHICH OF THE ABOVE SIX FACTORS PRESENTS THE GREATEST POTENTIAL IMPACT TO THE GENERAL PUBLIC?

A. The location of service lines being closer to buildings presents perhaps the greatest potential impact to the general public. These services are attached directly to homes, apartment buildings, and businesses such as hospitals, nursing homes, places of worship, or movie theaters and therefore pose a major risk for harm if a hazardous failure occurs. The risk posed by the failure

[4] Company Response to Discovery Request RCR-G-ENG-0009.

of these services not only affects Company employees working on the system, but also first responders (fire/police departments), families, and the unsuspecting public.

Q. ARE THERE ANY OPERATING POLICIES OF THE COMPANY WHICH MAY HAVE CONTRIBUTED TO THE RISING AMOUNT OF EXCAVATION DAMAGE TO SERVICE LINES?

A. Yes. The Company, like most gas companies, has been replacing older steel service lines and installing new service lines - where pressure conditions permit - with a plastic material type. These plastic materials cannot resist excavation damage as well as the former steel material. The following section of my testimony (Section IV) describes this type of risk.

IV. <u>Continuing Installation of "Most-Risky" Asset</u>

Q. HAVE YOU REVIEWED THE COMPANY'S MOST RISKY ASSETS?

A. Yes. I have reviewed the Company's most risky assets to see if they are being controlled over time and whether or not they are being eliminated through the Company's pipe replacement policies. This information is presented in the Company's confidential DIMP reports.

Q. COULD YOU PLEASE EXPLAIN THE IMPORTANCE OF THE DIMP AND ITS FEDERAL MANDATES?

A. Yes. PHMSA has published a rule establishing mandatory integrity management (IM) requirements for gas distribution pipeline systems. Operators were given until August 2, 2011 to write and implement their first distribution integrity management programs (DIMPs)[5]. These programs were required to incorporate several elements including the following:

- Identify existing & potential threats

[5] Source: https://primis.phmsa.dot.gov/dimp/

- Evaluate and rank risks
- Identify and implement measures to address risks

Q. HAS THE COMPANY AGREED WITH PHMSA THAT THE PURPOSE OF THE DIMP IS TO REDUCE ITS RISKS?

A. Yes. **BEGIN CONFIDENTIAL** [redacted][6] **END CONFIDENTIAL**

Q. PLEASE DESCRIBE THE HIGHEST RISKS IN THE COMPANY'S PIPING.

A. **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL**

Q. HAS THE COMPANY'S LIST OF MOST-RISKY ASSETS CHANGED OVER TIME?

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[6] Company's 2017 DIMP, page 8.
[7] Company's 2017 DIMP, page 19.

A. **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL**

V. <u>Potential Delay in Completion of Large Replacement Expense</u>

Q. HAVE YOU REVIEWED THE MAJOR EXPENDITURES THAT THE COMPANY HAS INCLUDED IN ITS POST-TEST YEAR PERIOD?

A. Yes. I have reviewed these major expenditures.

Q. ARE THERE ANY MAJOR EXPENDITURES THAT MAY NOT BE IN SERVICE BY THE END OF THE POST-TEST YEAR PERIOD?

A. Yes. One Facility Replacement project – the Crown Central Transmission Pipeline Replacement Project – may not be in service by the end of the post-test year period. Expenses of $19.9 million for this project are forecasted by the Company to be in service by December 2018. The largest portions of this expense will begin in July 2018 when directional drilling starts and will continue through December 2018 at a rate of about $2-3 million per month.[8]

Q. CAN YOU EXPLAIN THE DIRECTIONAL DRILLING TECHNIQUE?

A. Yes. Directional drilling is a fairly recent pipe replacement technique. It replaces the traditional direct burial technique for certain special replacements. Under the traditional burial technique, a ditch is first dug a few feet down in the ground for the length of the replacement and then the pipe is lowered into the ditch. The directional drilling pipe replacement technique does

[8] Company response to RCR-G-ENG-0013, Attachment "Crown Central Transmission Replacement Project Expenditures.xlsx".

not use a ditch. Instead, it creates a hole in the ground the entire length of the replacement using an underground drill head that can be controlled from above ground. After the hole is drilled, the replacement pipe is driven or pulled through the hole from one end.

Q. CAN YOU EXPLAIN THE RISKS INHERENT IN THE DIRECTIONAL DRILLING TECHNIQUE?

A. Yes. Directional drilling projects have a checkered on-time completion record due to unknown underground complications that can arise during the drilling and pipe-movement procedures. Occasionally, the drilling has to be restarted when unknown underground structures are encountered, or the pipe is damaged, resulting in a delay in completion of the installation. Counting on sufficient completion of the project in the final month of the post test year period, in order to put it into service at that time, such as the Company is proposing for this pipeline replacement, carries much risk.

VI. <u>Status of Major Replacement Programs</u>

Q. WHAT ARE THE MAJOR RECENT REPLACEMENT PROGRAMS AT PSE&G?

A. There are two major replacement programs in the current Rate Case: Energy Strong and Gas System Modernization Program ("GSMP").

Q. CAN YOU DESCRIBE THE KEY ASPECTS OF THE ENERGY STRONG GAS PROGRAM?

A. The Board approved the Company's Energy Strong Program on May 21, 2014, authorizing investments up to $1 billion, consisting of $600 million in electric infrastructure investments and $400 million in natural gas infrastructure investments, all of which were allowed to be recovered through a special ratemaking mechanism.[9] The gas program included two subprograms: UPCI Replacement, and M&R Station Flood Mitigation. The UPCI Replacement subprogram included replacement and uprating of approximately 250 miles of pipe; and the M&R Station subprogram included installing storm hardening measures at five M&R Stations, one Liquefied Petroleum Gas ("LPG") storage facility, one Liquid Propane Air ("LPA") facility, and one Liquefied Natural Gas ("LNG") Plant.

Q. PLEASE DESCRIBE THE CURRENT STATUS OF THE TWO ENERGY STRONG SUBPROGRAMS.

A. The Company installed approximately 240 miles of plastic and cathodically-protected steel mains to replace cast iron main in flood zones and upgraded these areas from utilization pressure (UP) to higher operating pressure. Along with the main replacement, PSE&G replaced approximately 21,000 unprotected steel services.

All eight M&R Stations are now in service. However, one (the Newark Airport M&R Station) is not quite complete, pending the settlement of lease negotiations between PSE&G and the City of Newark, as well as land use and other approvals involving the City of Newark and the Port Authority of New York and New Jersey.[10] Overall, I believe that within the engineering areas that I reviewed, the Company has proceeded within the terms of the Energy Strong stipulation.

Q. PLEASE DESCRIBE THE REVIEW PROCESS FOR THE TWO ENERGY STRONG SUBPROGRAMS.

A. In addition to the standard practice of review by the Board Staff and Rate Counsel, the Energy Strong subprograms were reviewed intensely during their entire process by an outside firm

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[9] In the Matter of the Petition of Public Service Electric & Gas Company for Approval of the Energy Strong Program, Docket No. EO13020155 and GO13020156, Order Approving Stipulation of Settlement, May 21, 2014, p. 5.

[10] Company Response to RCR-G-ENG-0006.

approved by all parties. Pegasus, the consulting firm, had only a monitoring role and met quarterly with Staff and Rate Counsel to explain their opinions of the progress of the program and answer all questions raised.

Q. CAN YOU DESCRIBE THE KEY ASPECTS OF THE GSMP PROGRAM?

A. Yes. The GSMP I program was approved by the Board in Docket No. GR15030272 as part of a Settlement Agreement between the parties in that proceeding. Costs eligible for recovery under the GSMP Accelerated Rate Recovery Mechanism include: (a) costs to replace PSE&G's UPCI mains and associated services and Unprotected Steel mains and associated services; (b) costs required to uprate the UPCI systems (including the uprating of associated protected steel and plastic mains and associated services) to higher pressures; and (c) costs associated with the installation of excess flow valves and the elimination of district regulators, where applicable. Under this program the Company was authorized to spend up to $905 million over three years to replace up to 510 miles of utilization pressure cast iron ("UPCI") main and unprotected steel main and services, uprate the UPCI system to higher pressure, install excess flow valves, and abandon district regulators.[11] Of the $905 million approved for GSMP, the Company is authorized to invest up to $650 million and install up to 400 miles of main to be recovered by the "Alternative Rate Mechanism."

Other costs to replace elevated pressure cast iron mains ("EPCI"), limited plastic and cathodically-protected steel mains associated with the UPCI and unprotected steel replacement projects, the costs to reinforce EPCI joints, and the additional costs associated with the relocation

[11] In the Matter of the Public Service Electric and Gas Company for Approval of a Gas System Modernization Program and Associated Cost Recovery Mechanism, Docket No. GR15030272, Order, November 16, 2015. The Company was allowed to spend up to $650 million to be recovered through an Alternative Rate Mechanisms with the remaining expenditures being recovered through the normal ratemaking process. As part of the program approval the Company was allowed to replace to up to 400 miles of main recovered through the Alternative Rate Mechanisms, as well as replace at least 110 miles of main in which costs would be recovered through a base rate case proceeding.

of inside meter sets associated with main replacement in the Program were only permitted as a part of the Stipulated Base. In its stipulated base, PSE&G must spend a minimum of $85 million per calendar year from 2016 through 2018 and during the three years 2016 – 2018, PSE&G must install and place in service no less than a total of 110 miles of main to replace cast iron and unprotected steel mains and associated services.

Q. HAS THE COMPANY BEEN MEETING THE SPENDING AND MILEAGE TERMS OF THE STIPULATED PROGRAM?

A. Yes and No. For the Accelerated portion of the program by the end of 2017, the Company had expended a total of $403.6 million (62.1 percent of its maximum allowable) and had installed a total of 222 miles of new main (55.5 percent of its original estimate). The Company's projection through the end of the Post-Test Year is that it will spend virtually all of the Budget ($649.97 Million out of the Budgeted $650 Million). However, it now projects that only 330 miles of main will be installed versus the maximum permitted of 400 miles, due to increased costs per mile that it has recently been experiencing.

Q. HAS THE COMPANY BEEN MEETING THE SPENDING AND MILEAGE TERMS OF THE STIPULATED BASE?

A. Yes. For the first two years of the program, the Company has invested more than the stipulated minimum of $85 million per year, with expenditures of $94.8 million in 2016 and $99.9 in 2017. The Company has also installed a total of 99 miles of piping during the first two years and expects to meet the minimum installation requirement of 110 miles by the end of the third year of the program. Therefore, I believe that within the engineering areas that I reviewed, the Company is exceeding the spending and mileage terms of the stipulated base, although falling short of mileage anticipated in the Accelerated Rate Mechanism portion of GSMP.

VII. Pipe-Sizing for the Major Replacement Programs

Q. AS PART OF YOUR REVIEW OF PIPE REPLACEMENTS IN BOTH THE ENERGY STRONG AND THE GSMP PROGRAMS DID YOU REVIEW AND COMPARE THE SIZES OF PIPE REMOVED VERSUS THE SIZES USED TO REPLACE THEM?

A. Yes.

Q. HOW WAS YOUR REVIEW UNDERTAKEN?

A. We started with a breakdown at the project level giving detail of the diameter of the replacement pipe and the diameter of the pipe being replaced individually under Energy Strong Replacements, GSMP Replacements, and GSMP Stipulated Base Replacements[12].

Q. WHAT WERE YOU SPECIFICALLY LOOKING FOR?

A. We wanted to be sure that the smallest-diameter (and thus least-cost) piping that was suitable for each application was being used for replacements.

Q. ARE THERE ANY QUESTIONABLE REPLACEMENTS IN EITHER OF THE TWO MAJOR REPLACEMENT PROGRAMS?

A. Yes. The Company has been replacing a small number of pipes with what appear to be oversized piping. Much of this oversizing appears to be due to an outdated replacement policy that resides in the Company's Gas Design Standards.

Q. WHAT IS THE REPLACEMENT POLICY THAT APPEARS TO BE OUTDATED?

A. The Design Standard in question is the Gas Design Standard specifying that: "Four-inch is the minimum UP main size to be installed."[13] The Company states it is following its Gas Design

[12] Discovery request RCR-G-POL-0047.
[13] Discovery Attachment RCR-G-ENG-0019_Main Replacement Size Review.xls.

Standards when replacing – for instance – a two-inch unprotected steel main with a four-inch plastic main in a utilization-pressure system.

Q. CAN YOU EXPLAIN WHY THIS STANDARD MAY NEED TO BE UPDATED?

A. Yes. This Standard appears to be oriented to past conditions when utilization-pressure ("UP") systems were thought to remain intact for many future decades. Under this assumption it might be reasonable to make sure that a replacement main would not have to be replaced a second time in a future year when and if gas demand on that main increased significantly.

However, this assumption may no longer be applicable since the Company has now entered a new era wherein its UP systems are destined to be upgraded to elevated pressure in a relatively short time through accelerated replacement programs.

Three replacement jobs in the GSMP program (jobs identified as BSP-HR-3, BSP-OG-10, and BSP-TR-25), wherein two-inch unprotected steel mains in utilization-pressure systems were replaced with four-inch plastic mains (still at utilization-pressure), are explained as being due to the Design Standard in question.

To give some frame of reference, unprotected steel mains in the Company's system have not been installed since about 1960, and therefore these two-inch mains have provided sufficient gas volumes for at least fifty-eight years without needing to be upsized. Since these UP pipes will be uprated to higher pressures in the foreseeable future, the plastic replacement piping did not necessarily have to be of a larger diameter. A two-inch plastic pipe would likely be sufficient size for the few remaining years prior to being uprated.

Then, as soon as these portions of the system are uprated to elevated pressure, a two-inch plastic line would provide more than twice the amount of gas that has been supplied for the past fifty-eight years. Therefore, it is entirely possible that the same size plastic replacement pipe (two-inch diameter instead of the four-inch diameter piping installed by the Company) would have proven sufficient both before and after being uprated.

The Company never has to take a chance of a pipe being of insufficient size for the foreseeable future. The Company maintains computer-based flow/pressure models for every main in its system. If the Company had run flow/pressure simulations of these three jobs using projected demand for the near-future and foreseeable-future years - instead of strictly following its Gas Design Standard - it is entirely possible in our opinion that a smaller (two-inch) plastic pipe would have sufficed.

Q. WHAT WOULD BE YOUR RECOMMENDATION WHEN REPLACING UP MAINS SMALLER THAN FOUR-INCH DIAMETER?

A. When replacing UP mains smaller than four-inch, the Company should not automatically use four-inch piping, but should run pressure/flow simulations of the main being replaced in order to determine if a smaller size would suffice until the main would be uprated (at which time the maximum transportable gas volume in the new line will double) and to see if the smaller size would also suffice for the foreseeable future after uprating. In similar prior cases, Rate Counsel has taken the position that oversizing of pipes is the Company's prerogative, but the extra costs would not be permitted to be passed on to ratepayers.

Q. IS THERE ANYTHING THAT THE COMPANY SHOULD DO IN THIS AREA AT THIS TIME?

A. Yes. I would recommend that the Company review all of its Gas Design Standards at this time in order to determine if there are other minimum-size installation Standards that should also be updated, and modify them as necessary.

Further, I would recommend that the Company review the sizing of all piping in the Energy Strong and GSMP programs to determine which installations – if any – should be disallowed in this Rate Case due to minimum-size Standards, and notify all parties of the amount that should be disallowed.

VIII. Leak Reduction Performance and Improved Metrics

Q. PLEASE EXPLAIN THE LEAK REDUCTION TARGETS ASSOCIATED WITH THE ENERGY STRONG AND GSMP PROGRAMS

A. The Board's approval of the Energy Strong program included a requirement that the Company reduce its open leak inventory (1,937 of leaks existing as of December 31, 2013) by 582 leaks (30 percent) within the first three years of the Energy Strong Program (or 194 leak reductions per year).[14] The Board's approval of the GSMP I requires the Company to reduce its open leak inventory, as of September 30, 2015, by 60 percent over the three-year period of September 30, 2015 through September 30, 2018.[15]

Q. WERE THE LEAK REDUCTION MEASURES OF ENERGY STRONG AND GSMP SUCCESSFUL SINCE THE COMPANY MET THE LEAK REDUCTION TARGETS OF THE STIPULATIONS?

A. No, not completely. They did accomplish a reduction in the number of leaks that were outstanding at the end of one year by reducing them over time. However, new leaks that occurred in succeeding years were not covered by the leak reduction requirement. As a result, the leaks existing at the end of each future year were not subject to the leak reduction requirement.

[14] In the Matter of the Petition of Public Service Electric & Gas Company for Approval of the Energy Strong Program, Docket No. EO13020155 and GO13020156, Order Approving Stipulation of Settlement, May 21, 2014, Stipulation, p. 16.
[15] In the Matter of the Public Service Electric and Gas Company for Approval of a Gas System Modernization Program and Associated Cost Recovery Mechanism, Docket No. GR15030272, Order, November 16, 2015, p. 4.

Therefore, changes have been made (and a penalty introduced) for future leak reduction requirements as explained below.

Q. HAVE ANY CHANGES BEEN MADE TO MAKE FUTURE LEAK REDUCTION REQUIREMENTS MORE EFFECTIVE?

A. Yes. An extension of the GSMP program has recently been approved by the Board. The extension Program (called GSMP-II), will be implemented over a five (5) year term, commencing on January 1, 2019, and ending December 31, 2023. The extended program is also a pipe-replacement program.

The leak-reduction metric ordered for this GSMP-II program is improved from the ones used in the Energy Strong and GSMP-I programs. In the GSMP-II settlement, the Company agreed to reduce its year-end open leak inventory by one (1) percent for each year of the Program, except under extraordinary circumstances, such as "Major Event" (as defined at *N.J.A.C.* 14:5-1.2), acts of war or terrorism, or other *force majeure* extraordinary circumstances.

This open leak reduction metric includes, under its annual leak-reduction caps, all post-approval open leaks for each year of the Program. The cap for the first year following the date of Board approval was set at the average number of year-end open leaks the Company had experienced during the past five calendar years. Thereafter, the caps are reduced by one (1) percent for each of the remaining four years of the GSMP-II Program.

Q. WERE THERE ANY PENALTIES AGREED UPON FOR FAILURE TO MEET THE ANNUAL CAP ON THE NUMBER OF OPEN LEAKS?

A. Yes. The Board Order approving the settlement of GSMP-II requires that if the Company exceeds the open-leak performance cap in the first two years of the Program, the Company will notify Board Staff and Rate Counsel and schedule a conference within thirty (30) days to discuss the matter. Consistent with the Board Infrastructure Investment and Recovery regulation ("IIP"), *N.J.A.C.* 14:3-2A.1 *et. seq*., if the Company exceeds the cap for a third consecutive year, the Company will reduce its return on equity ("ROE") under the Program by fifty (50) basis points until it achieves the leak reduction target. PSE&G may request, and the Board may grant, an exception from the requirements of this paragraph based on extraordinary circumstances, such as "Major Event", acts of war or terrorism, or other *force majeure* extraordinary circumstances.

IX. <u>Conclusions and Recommendations</u>

A) **Conclusions:**

1) The Company's operating performance statistic of "Leak Damages per 1,000 Locate Requests" has been rising in recent years. The Company's performance has gone from being better than the performance of two groups of comparable gas companies in 2009, to now being worse than both groups in 2016.
2) Plastic service lines suffering Excavation Damage have risen from being the Company's fourth-highest asset risk in 2014, to becoming the Company's highest-risk asset in 2017.
3) It is doubtful that one of the Company's current construction projects (the Crown Central Transmission Pipeline Replacement Project) will be in-service by the end of the Post Test period (December 2018).
4) The Company's reliance on one of its Gas Design Standard replacement policies may be unnecessarily expensive.
5) The leak-reduction stipulations in the Energy Strong, GSMP, and earlier programs resulted in leak reductions for leaks that were discovered in only one year. A new leak

reduction metric was established after the Energy Strong program, which better controls the number of outstanding leaks at the end of each future year.

B) Recommendations:

1) The Company is no longer keeping up with other comparable gas utilities in one of its key performance measures: Leak Damages per 1,000 Locates. The Company is no longer attaining its target of being in the top quartile of comparable gas utilities; and has recently fallen below the median of these utilities. The Company should dedicate more resources and develop additional programs toward stemming the rise in this operating performance statistic.

2) The Company's plastic service lines that are subject to excavation damage have now risen to its most-risky asset. The Company should dedicate more resources toward stemming the hazardous risks to the Public of excavation damage to these service lines. An example of a step that might be taken includes sponsorship of an industry research program that would analyze the ways to best protect the type of material used in its plastic services.

3) Since it is doubtful that the Company's Crown Central Transmission Pipeline Replacement Project will be in service by December, 2018, we recommend that its estimated cost of $19.9 Million be removed from inclusion in the list of capital expenditures scheduled for the Post Test Year.

4) Since UP systems are being replaced in significant numbers in recent years, one of the Company's Gas Design Standards that requires a minimum mains replacement size of four-inch-diameter appears to be too conservative. We recommend that when sizing replacement piping for smaller-diameter UP mains, the Company should run

flow/pressure simulations of projected gas demand in these mains for the near-future – instead of following its current Gas Design Standard. In similar prior cases, Rate Counsel has taken the position that oversizing of pipes is the Company's prerogative, but the extra costs would not be permitted to be passed on to ratepayers.

I would also recommend that the Company review all of its Gas Design Standards at this time in order to determine if there are other minimum-size installation Standards that should also be updated, and modify them as necessary. Further, I would recommend that the Company review the sizing of all piping in the Energy Strong and GSMP programs to determine which installations – if any – should be disallowed in this Rate Case due to minimum-size Standards, and notify all parties of the amounts that should be disallowed.

5) Since the leak-reduction stipulations in the Energy Strong, GSMP, and earlier programs resulted in leak reductions for leaks that were discovered in only one year, an alternate formulation has been introduced for the very recent GSMP-II program that we recommend for use in future programs. The new formulation will continuously reduce all outstanding leaks throughout each year of the program.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, although I reserve the right to supplement my testimony if any updated or additional information becomes available during the course of this proceeding.

CREDENTIALS OF EDWARD A. McGEE

PROFESSIONAL CAREER:

2012 – Present **Acadian Consulting Group** ***Engineering Associate***
As Engineering Associate for Acadian Consulting Group, I am responsible for assisting in studies performed for Public Utility Commissions.

1999 – Present **McGee Consulting** ***Principal Consultant and Engineer – Energy Industry***
As Principal Consultant and Engineer, I am responsible for assisting larger consulting firms in their studies performed for utility companies and Public Utility Commissions.

1985 - 1999 **Stone & Webster Management Consultants, Inc.** ***Vice President/Director***
As Vice President of Stone & Webster Management Consultants, I was responsible for consulting studies in the Gas Practice area, where I performed consulting analyses in the gas planning and gas operations areas for gas utility companies and public utility commissions.

1982 - 1985 **Stone & Webster Engineering Corporation** ***Business Development Manager***
As Business Development Manager at Stone & Webster Engineering Corp., I was responsible for the construction of investment models for feasibility studies on largescale chemical and refining complexes.

1982 & earlier **W. R. Grace & Co.** ***Director of Energy Resources; Manager of Chemical Development***
As Director of Energy Resources for W. R. Grace, I advised the Chief Operating Officer on corporate energy consumption and production. I also assisted operating divisions in securing long-term energy resources.
As Manager of Chemical Development at W. R. Grace, I analyzed potential acquisition targets in specialty chemical and high technology fields, developing corporate strategies for selected expansions.

AMOCO Oil ***Supervisor of Technical Computer Programming; Internal Operations Research Consultant***
In a variety of engineering and computer modeling capacities at AMOCO Oil directed a staff of professionals in the development of technical programs in the refining, distribution and marketing areas.

EDUCATION:

University of Chicago, Master of Business Administration, Quantitative Analysis

and Computers
University of Notre Dame, Master of Science in Chemical Engineering
University of Notre Dame, Bachelor of Science in Chemical Engineering

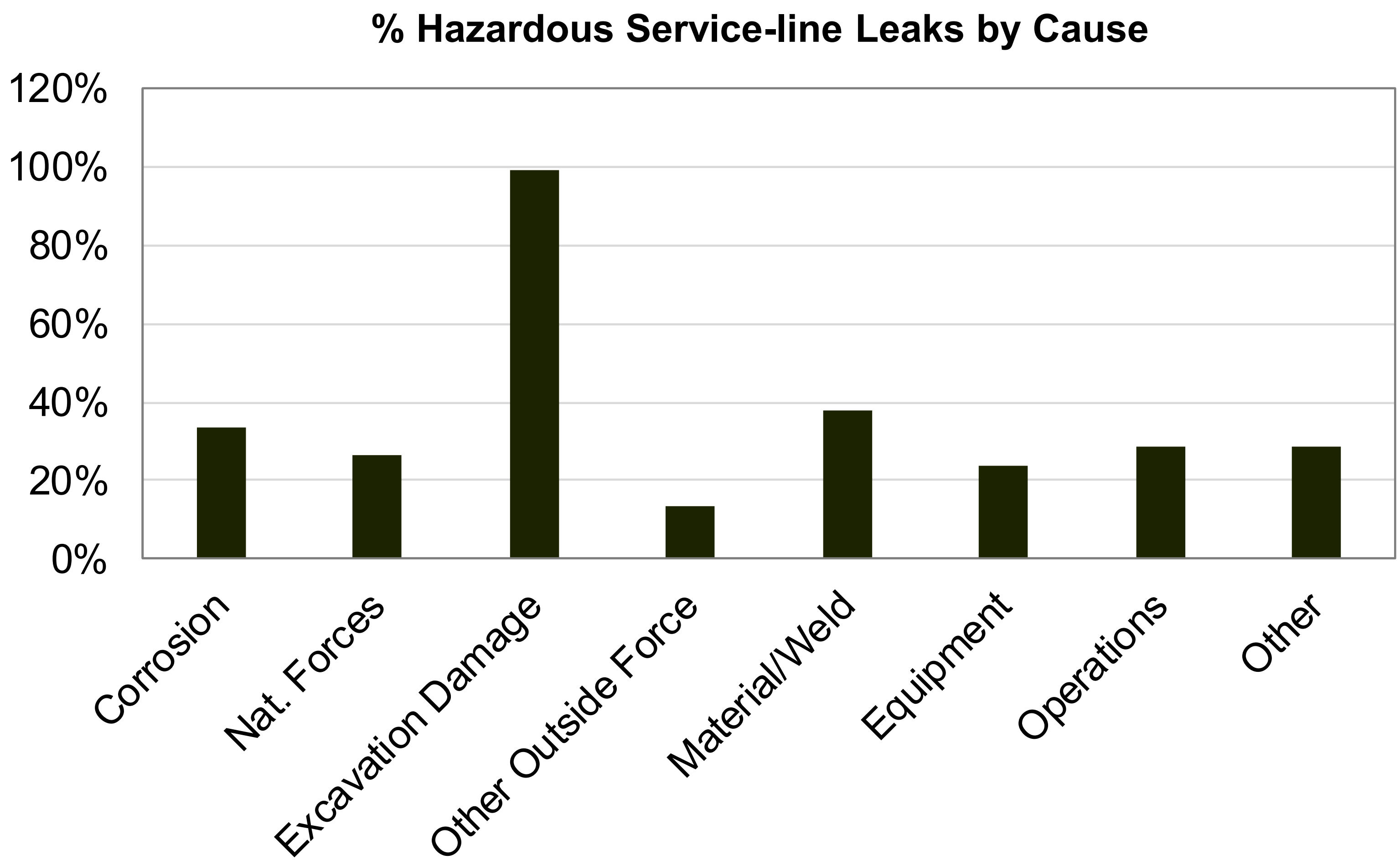
LICENSES & CERTIFICATES:
Licensed Professional Engineer (License Currently Retired) -- State of Indiana
U.S. Patent Holder -- Refinery Treating Process

PROFESSIONAL AFFILIATIONS:
American Institute of Chemical Engineers
The Institute of Management Sciences

SAMPLE PUBLICATIONS AND PAPERS:
"Using a Personal Computer as a Gas Supply Planning Tool." ***Gas Industries*** lead article.
"Personal Computers and the Natural Gas Industry." ***Public Utilities Fortnightly***.
"Personal Computer-Based Long-Range Planning for Natural Gas Development and Supply Management." Presented at the ***International Gas Union's 18th World Gas Conference***, Berlin, Germany.
"Role of Optimization Models in Dispatching Gas Supplies." Presented at ***AGA Distribution/Transmission Conference***, Toronto, Canada.
"Experience With Gas Supply Optimization Models at Inland Natural Gas." Presented at ***IGT symposium on Personal Computers in the Gas Industry***, Chicago, Illinois.

Table of Schedules

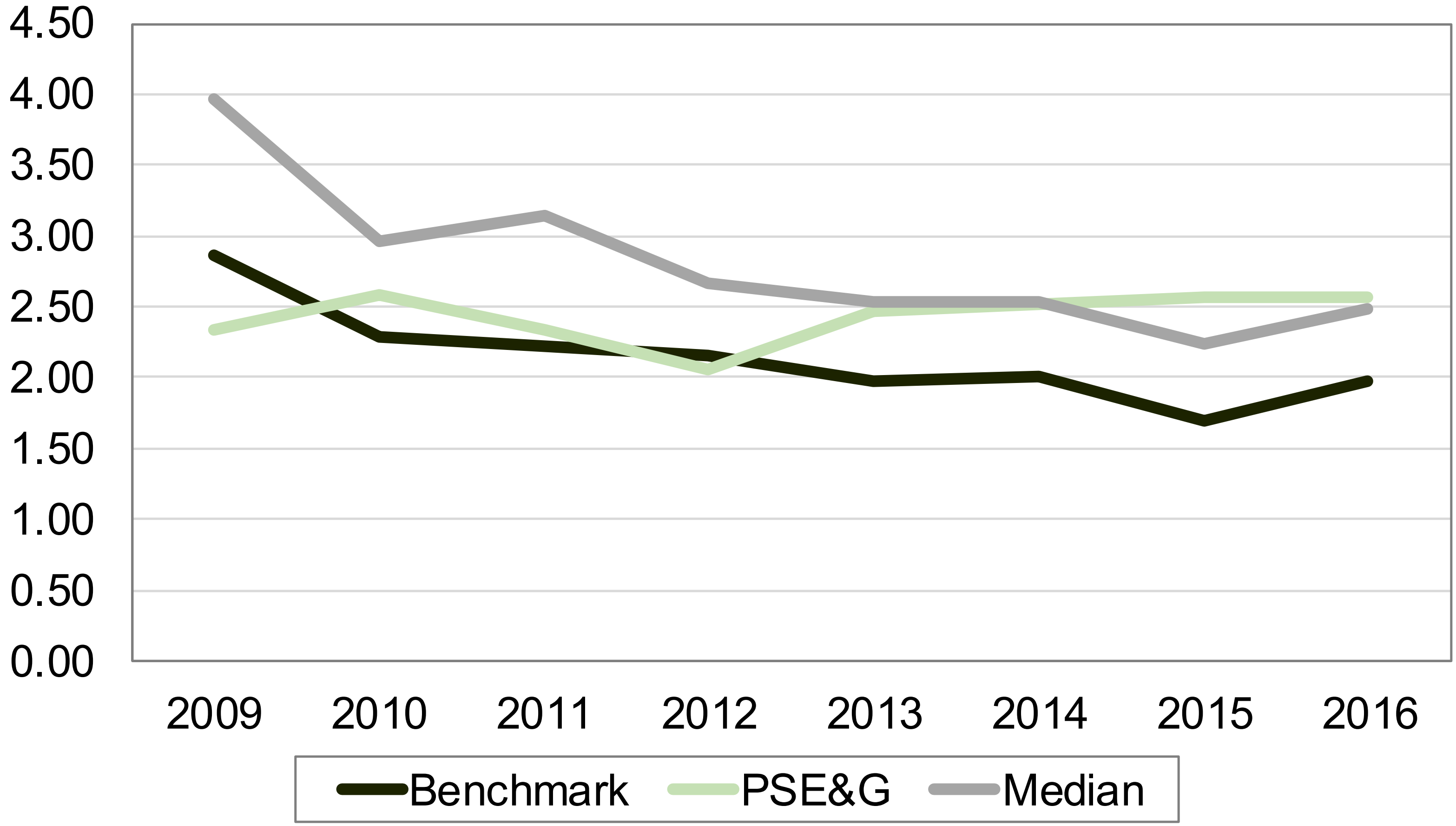
Percentage of Service-line Leaks Classified as Hazardous In 2017



Source: Company's 2017 Annual Gas Distribution Report, Form PHMSA F 7100.1-1.

Excavation Damage per 1,000 Locates Benchmark

Number of Damages to Gas Facilities per 1,000 Locate Requests



Note:
(a) Benchmark represents top-quartile of comparable companies.
(b) Median represents top-half of comparable companies.
Source: Company response to RCR-G-POL-0015.

PSE&G 2017 DIMP Relative Risk Ranking Results

[redacted]

Source: Company's 2017 Distribution Integrity Management Plan, p. 19.

PSE&G 2017 DIMP Relative Risk Ranking Results

[redacted]

Source: Company's 2017 Distribution Integrity Management Plan, p. 19.