**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

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RE: IN THE MATTER OF ADVICE LETTER NO. 912-GAS FILED BY PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC NO. 6-GAS TARIFF TO IMPLEMENT A GENERAL RATE SCHEDULE ADJUSTMENT AND OTHER RATE CHANGES EFFECTIVE ON 30-DAYS NOTICE.	**)))))))**	**PROCEEDING NO. 17AL-____G**

<u>DIRECT TESTIMONY AND ATTACHMENTS OF LUKE A. LITTEKEN</u>

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

June 2, 2017

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

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SUMMARY OF DIRECT TESTIMONY OF LUKE A. LITTEKEN

Mr. Luke A. Litteken is Area Vice President, Gas Operations of Xcel Energy Services Inc. (“XES”). In this position, Mr. Litteken has oversight for the operation and maintenance of the gas distribution and high-pressure systems in each state in which Xcel Energy operates a gas system, including for Public Service Company of Colorado (“Public Service” or the “Company”). Mr. Litteken’s responsibilities include gas control center operations, system reliability, damage prevention, emergency response, and compliance with federal and state rules and regulations.

In his Direct Testimony, Mr. Litteken supports two programs that Public Service is proposing in this proceeding. These programs include the Enhanced Emergency Response Program and the Damage Prevention Program.

With respect to the Enhanced Emergency Response Program, Mr. Litteken first addresses the program approved in the last gas rate case, Proceeding No. 15AL-0135G (“2015 Phase I”) and whether the Company met the metric established in order to recovery its deferred costs related to the program. The Company has been able to reduce its average response time from 133 minutes to under 60 minutes. As such, Mr. Litteken recommends that the Colorado Public Utilities Commission ("Commission") approve the 2016 and 2017 deferred costs be amortized over an 18 month period if an HTY is approved or if an MYP is approved be amortized over a 24 month period beginning on January 1, 2019. However, Mr. Litteken next explains the need for the second phase of this program or Enhanced Emergency Response Program 2.0. Mr. Litteken testifies regarding the need for additional emergency responders, trouble repair positions and a supervisor. The Company has forecasted the Operations and Maintenance ("O&M") for the Multi-Year Plan ("MYP") period, calendar years 2018, 2019 and 2020. If a historical test year is approved, Mr. Litteken recommends that the costs be deferred and a regulatory asset established.

As to the Damage Prevention program for which the Commission approved a deferral accounting mechanism in the 2015 Phase I, Mr. Litteken testifies that the 2016 and 2017 deferred costs related to locate requests are reasonable and the Commission should approve the amortization over an 18 month period if an HTY is approved or if an MYP is approved be amortized over a 24 month period beginning on January 1, 2019. Because the costs related to locate requests remain significant and volatile, Mr. Litteken also recommends that the Commission approve such costs incurred over the amount of $13.1 million included in base rates be deferred and a regulatory asset established.

Finally, Mr. Litteken provides support for the Supervisory Control and Data Acquisition ("SCADA")/Gas Control Monitoring Improvement Program. As part of this discussion, Mr. Litteken testifies regarding the Commission directives regarding this program in the 2015 Phase I and the cost benefit analysis undertaken justifying the program.

**BEFORE THE PUBLIC UTILITIES COMMISSION
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DIRECT TESTIMONY AND ATTACHMENTS OF LUKE A. LITTEKEN

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LIST OF ATTACHMENTS

GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
AGA	American Gas Association
CNP	CenterPoint Energy
Colorado 811	Utility locating service
Commission	Colorado Public Utilities Commission
HTY 2016	Historical Test Year – Calendar Year 2016
LNG	Liquid natural gas
LPG	Liquid Propane Gas
MYP	Multi-Year Plan
O&M	Operations & Maintenance
OSHA	Occupational Safety and Health Administration
2015 Phase I	Gas Phase I rate case Proceeding No. 15AL-0135G
Public Service or the Company	Public Service Company of Colorado
SCADA	Supervisory Control and Data Acquisition
HTY	Historic Test Year January 1, 2016 through December 31, 2016
XES	Xcel Energy Services, Inc.
Xcel Energy	Xcel Energy Inc.

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

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RE: IN THE MATTER OF ADVICE LETTER NO. 912-GAS FILED BY PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC NO. 6-GAS TARIFF TO IMPLEMENT A GENERAL RATE SCHEDULE ADJUSTMENT AND OTHER RATE CHANGES EFFECTIVE ON 30-DAYS NOTICE.	**) PROCEEDING NO. 17AL-____G**

DIRECT TESTIMONY AND ATTACHMENTS OF LUKE A. LITTEKEN

I. INTRODUCTION, QUALIFICATIONS, PURPOSE OF TESTIMONY, AND RECOMMENDATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Luke A. Litteken. My business address is 1123 West 3rd Avenue, Denver, Colorado 80223.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am employed by Xcel Energy Services, Inc. (“XES”), a wholly-owned subsidiary of Xcel Energy Inc. (“Xcel Energy”), the parent company of Public Service Company of Colorado (“Public Service” or the “Company”). XES provides an array of support services for Public Service and the other utility subsidiaries of Xcel Energy. My position is Area Vice President, Gas Operations. In this position, I am responsible for operations and maintenance of the gas distribution and high-pressure systems in all the states in which Xcel Energy operates: Colorado, Michigan, Minnesota, North Dakota, South Dakota, Texas, and Wisconsin.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THE PROCEEDING?

A. I am testifying on behalf of Public Service.

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AND QUALIFICATIONS.

A. As Area Vice President, Gas Operations, I have oversight of Xcel Energy's operations and maintenance of the gas distribution and high-pressure systems in each state in which Xcel Energy operates a gas system, including the gas control center operations. I am responsible for operational performance and maintenance of Xcel Energy's multi-state gas transmission and gas distribution systems. Responsibilities include management and oversight of system reliability, damage prevention, emergency response, LNG/LPG gas plants and gas storage field operations, compliance with federal and state rules and regulations, and leadership over Xcel Energy's Gas Operations bargaining and non-bargaining employees, contractors, and outside vendors. A statement of my education and relevant experience is set forth following my Direct Testimony.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my Direct Testimony is three-fold. I first testify regarding the Company's Enhanced Emergency Response Program and the related deferral mechanism that was approved in the Company's last Gas Phase I rate case, Proceeding No. 15AL-0135G ("2015 Phase I"). I also describe the Company's proposal to implement the second phase of this program called the Enhanced

Emergency Response Program 2.0 in the Multi-Year Plan ("MYP") to further reduce its average emergency response time. Second, I testify regarding Public Service's Damage Prevention Program and the related deferral mechanism that was approved in the 2015 Phase I. I also explain Public Service's proposal to extend the deferral mechanism as there is continued fluctuation in the number of locate tickets from year to year. Finally, I provide support for the Supervisory Control and Data Acquisition ("SCADA")/Gas Control Monitoring Improvement Program. As part of this discussion, I testify regarding the Commission directives regarding this program in the 2015 Phase I and the cost benefit analysis undertaken justifying the program.

Q. ARE YOU SPONSORING ANY ATTACHMENTS AS PART OF YOUR DIRECT TESTIMONY?

A. Yes, I am sponsoring six Attachments in this proceeding. Attachment LAL-1 summarizes the costs in the Enhanced Emergency Response Program deferred account that was approved in the 2015 Phase I. Attachment LAL-2 contains damages per 1,000 locates for the years 2007 through 2016. Attachment LAL-3 is the number of gas locate requests for the years 2013 through 2016. Attachment LAL-4 summarizes the costs in the Damage Prevention Program deferred account that was approved in the 2015 Phase I. Attachment LAL-5 summarizes several significant events that were avoided due to proactive system monitoring. Attachment LAL-6 provides an overview of the cost benefit analysis performed for the SCADA/Gas Control Monitoring Improvement program.

Q. WHAT RECOMMENDATIONS ARE YOU MAKING IN YOUR DIRECT TESTIMONY?

A. I recommend that the Commission approve the following:

(1) the amortization over an 18 month period if an HTY is approved or if an MYP is approved be amortized over a 24 month period beginning on January 1, 2019 of the 2016 and 2017 deferred costs associated with the Enhanced Emergency Response Program approved in the 2015 Phase I;

(2) the Enhanced Emergency Response Program 2.0 and the forecasted amounts included in the MYP. If a historical test year ("HTY") is approved, then I recommend that a deferred accounting mechanism be approved;

(3) the amortization over an 18 month period if an HTY is approved or if an MYP is approved be amortized over a 24 month period beginning on January 1, 2019 2016 and 2017 deferred costs associated with locate requests as these costs are reasonable;

(4) a continued deferred accounting mechanism related to locate requests as the costs remain significant and volatile; and

(5) the costs associated with the SCADA/Gas Control Monitoring Improvement Program.

II. ENHANCED EMERGENCY RESPONSE PROGRAM

Q. PRIOR TO THE 2015 PHASE I, WHAT WAS PUBLIC SERVICE'S EMERGENCY RESPONSE TIME?

A. For 2013, Public Service's average emergency response time was 133 minutes. Based on a benchmarking study prepared by the American Gas Association ("AGA"), Public Service was ranked in the fourth quartile for emergency response time in 2013. At the time, utilities in the top quartile had an emergency response time of 60 minutes or less. While emergency response times have not been codified across the United States, these utility benchmarks are based on best practices, which prioritize public safety and the minimization of property damage. Like our peer group, Public Service uses the AGA benchmarks as part of our strategic planning process. The benchmarks take a pragmatic approach to safety, in that they balance baseline service levels with costs, and have been helpful in improving key metrics, including emergency response time guidelines.

Q. AS A RESULT, WHAT DID THE COMPANY PROPOSE IN THE 2015 PHASE I?

A. In the 2015 Phase I, Public Service proposed a two-fold proposal to improve its response to gas emergencies. First, the Company proposed to create a dedicated gas dispatch center to promote a more focused and efficient process from the initial gas call handling to the timely dispatch of gas emergency orders instead of a combined electric and gas dispatch center. This dispatch center would consist of 14 dispatchers (seven who transferred in from the combined electric/gas dispatch center and an incremental seven positions), one order approver (responsible for order auditing and data accuracy), one supervisor, and one manager who will have oversight of two field emergency response crews for a total of 17 dispatch employees. Second, the Company proposed the addition of 18 additional field emergency responders throughout our service territory over the proposed MYP period.

Q. DID THE COMMISSION APPROVE THE COMPANY'S PROPOSAL?

A. No. Instead, the Commission approved Staff's proposal that (1) allowed a pro forma adjustment to the 2014 HTY of $1.6 million (representing the hiring of six responders and the creation of the gas dispatch center); and (2) defer and establish a regulatory asset for additional costs for this program in 2016 and 2017 (which includes the hiring of an additional 12 responders), with the requirement for tracking and meeting the metric of achieving an average response time of 60 minutes or less.[1] In my 2015 Phase I Rebuttal Testimony, I explained that should the Commission not adopt the proposed MYP, except for the proposed metric, the Company supported the Staff proposal as an alternative. In the 2015 Phase I, the Company expressed concern about the proposed metric because, based on the study it performed to support the

[1] See Decision No. R15-1204 at 63-64 and Decision No. C16-0123, Ordering ¶5.

program, 58 responders would need to have been added in order to achieve a 60 minute response time target.[2]

Q. BETWEEN 2015 AND 2017, DID PUBLIC SERVICE HIRE 18 EMERGENCY RESPONDERS?

A. Yes. Public Service hired all 18 responders since the 2015 Phase I. Following the appropriate training period for each responder, based on their individual experience, 12 of the 18 became productive throughout the past 24 months. The final six of the 18 will complete their training period later in 2017 and will then become productive in the gas emergency response workforce.

Q. DID PUBLIC SERVICE MEET THE METRIC OF ACHIEVING AN AVERAGE RESPONSE TIME OF 60 MINUTES OR LESS?

A. Yes. Figure LAL-D-1 Average Emergency Response Time depicts the improvements the Company has made to the average time to respond to gas emergency calls over the last five years. The company was able to meet the performance metric of 60 minutes or less, 57.6 minutes in 2016, with the help of many of the additional responders that were approved in the last gas rate case along with responders working overtime. Additionally, Public Service is forecasting an average emergency response time of 55 minutes in 2017 as a result of the final six responders of the 18 responders approved in the 2015 Phase I becoming productive in the second half of 2017.

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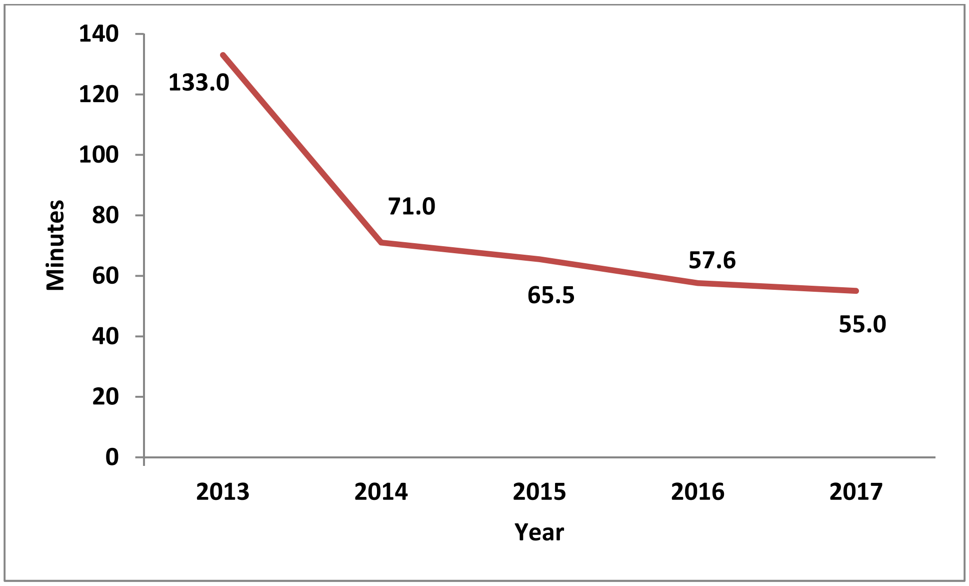
[2] See 2015 Phase I, Hearing Ex. 8, Litteken Rebuttal at 39.

Figure LAL-D-1 Average Emergency Response Time



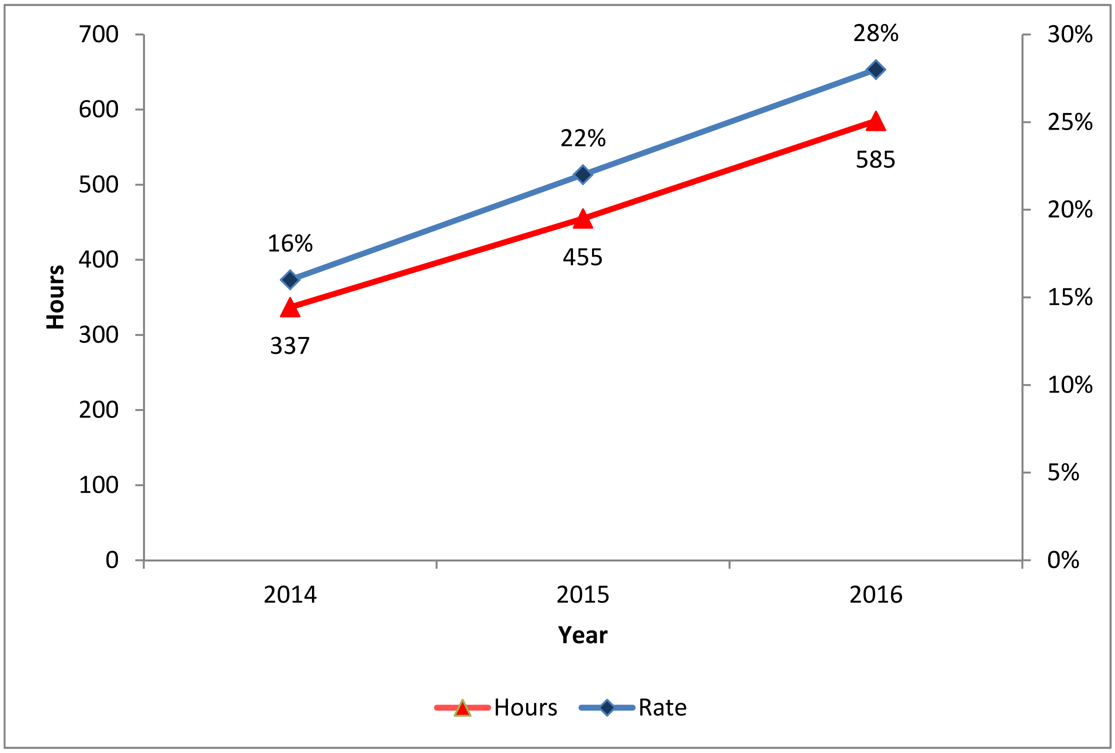
Q. SPECIFIC TO THE DENVER METRO AREA, WHAT WAS THE AVERAGE RESPONSE TIME IN 2014, 2015, AND 2016?

A. The Denver Metro area is Public Service's largest concentration of customers and over the last three years, the Company has tracked response times specific to this area. The Company's average response times in 2014, 2015, and 2016 were 71.0, 65.5, and 57.6 minutes respectively. Over the three year period, the average response time has improved 16 percent. Based on the improvements the industry has made in emergency response performance, the Company is not satisfied with its results.

Q WHAT LEVELS OF OVERTIME DID THE GAS EMERGENCY RESPONDERS IN THE DENVER METRO WORK OVER THE LAST THREE YEARS?

A. Figure LAL-D-2 depicts the amount of overtime associated with responding to gas emergency calls over the last three years in the Denver Metro area.

**Figure LAL-D-2 Gas Emergency Response - Denver Metro
Average Annual Overtime per Responder**



1 Overtime can be a useful tool to help manage workload peaks or special
2 projects, but sustaining a 28 percent overtime rate on an ongoing basis becomes
3 an employee safety concern as well as an increasingly inefficient use of
4 resources. The drivers for this overtime were the need for continuous response
5 time improvement while 18 new emergency responders were hired, trained and
6 released into the field with a normal ramp up in productivity.

Q. WHAT WERE THE ACTUAL COSTS ASSOCIATED WITH THE ENHANCED EMERGENCY RESPONSE PROGRAM THAT WAS APPROVED IN THE 2015 PHASE I?

A. The Commission approved a pro forma adjustment to the 2014 HTY of $1.6 million for hiring six responders and the dedicated gas dispatch center in 2015. The costs for the remaining 12 responders were allowed to be deferred and a regulatory asset for those costs was established. For 2016, the Company booked a total of $2,162,035 in the Enhanced Emergency Response regulatory asset. The Company forecasts the 2017 amount to be $3,844,199 for a total of $6,006,234. Attachment LAL-1 contains information on the 2016 actual deferral amount and the 2017 forecasted deferral amount for the Enhanced Emergency Response program that was approved in the 2015 Phase I. Because the Company has met the metric set forth by the Commission in its Decision in the 2015 Phase I, the Company should be allowed to recover these deferred costs. Public Service requests that the deferred balances for 2016 and 2017 related to the Enhanced Emergency Response Program regulatory asset be amortized over an 18 month period if an HTY is approved or if an MYP is approved be amortized over a 24 month period beginning on January 1, 2019. Public Service witness Mr. Stephen P. Berman further discusses the amortization of the deferral balances related to the regulatory asset for the Enhanced Emergency Response Program.

Q. THE COMPANY IS FORECASTING AN AVERAGE EMERGENCY RESPONSE TIME OF 55 MINUTES IN 2017 AS A RESULT OF THE HIRING OF 18 RESPONDERS THAT WERE APPROVED IN THE LAST RATE CASE. HOW DOES THIS RESPONSE TIME COMPARE TO THAT OF OTHER UTILITIES?

A. Although significant improvements have been made to reduce emergency response times, based on a benchmarking study prepared by the AGA utilizing 2015 data, an average response time of 55 minutes would still be ranked in the fourth quartile. Utilities in the top quartile had an average emergency response time of 24.28 minutes or less. Second quartile utilities had an emergency response time between 24.28 minutes and 28.00 minutes and third quartile utilities between 28.00 minutes and 35.33 minutes. Companies, like Public Service, with an average emergency response time greater than 35.33 minutes were in the fourth quartile.

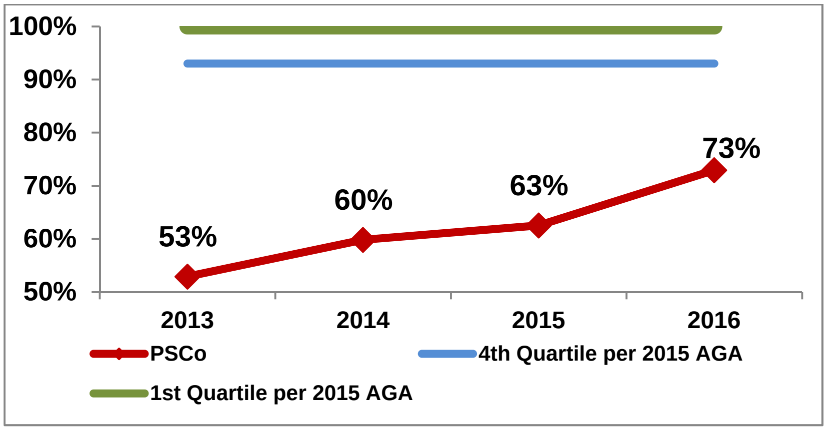
Q. IS THE INDUSTRY STILL UTLIZING THE STANDARD METHODOLOGY TO BENCHMARK EMERGENCY RESPONSE TIMES BY THE AVERAGE NUMBER OF MINUTES IT TAKES FROM THE TIME AN EMERGENCY CALL WAS RECEIVED TO WHEN THE FIRST UTILITY RESPONDER IS ON-SITE AT THE EMERGENCY LOCATION?

A. Although measuring the average minute response time provides a good indicator of how the Company is performing, the industry has moved toward measuring the percentage of all emergency calls responded to within 60 minutes rather than the average minutes of all emergency calls. In fact, the Company has followed suit and changed to this metric on its Gas scorecard.

Q. PLEASE DESCRIBE PUBLIC SERVICE'S PERFORMANCE UNDER THE INDUSTRY ACCEPTED METHODOLOGY AND HOW IT MEASURES AGAINST ITS PEERS.

A. As shown in Figure LAL-D-3, Percent of Gas Emergency Calls < 60 Minutes, in 2015 Public Service responded to 63 percent of all emergency calls within 60 minutes. This improved to 73 percent in 2016. Based on a benchmarking study prepared by the AGA utilizing 2015 data, responding to 73 percent of emergency calls within 60 minutes would still be ranked in the fourth quartile. Utilities in the top quartile responded to at least 98.83 percent of emergency calls within 60 minutes. Second quartile utilities responded to at least 97.40 percent of emergency calls within 60 minutes and third quartile utilities responded to at least 92.00 percent of emergency calls within 60 minutes. Fourth quartile companies responded to less than 92.00 percent of all emergency calls within 60 minutes. Public Service is trailing many in the industry, at 73 percent of all emergency calls responded to within 60 minutes which is in the fourth quartile.

Figure LAL-D-3, Percent of Gas Emergency Calls < 60 Minutes



Q. IS THE COMPANY SURPRISED IT REMAINED IN THE FOURTH QUARTILE IN THE AGA BENCHMARKING STUDY AFTER HIRING 18 ADDITIONAL EMERGENCY RESPONDERS SINCE THE LAST RATE CASE?

A. No. In my testimony in the 2015 Phase I, I stated that Public Service would need to hire 58 emergency responders in order to move into the top quartile. Additionally, I stated that "an additional 18 responder positions would be a good starting point toward our journey towards top quartile performance."[3]

Q. IS THE COMPANY PROPOSING TO MAKE ANY ADDITIONAL ENHANCEMENTS TO IT GAS EMERGENCY RESPONSE PROGRAM IN THIS PROCEEDING?

A. Yes. The Company proposes to continue its journey to improve response times to gas emergency calls that we started in 2015. For purposes in this proceeding, I will refer to this new program as Enhanced Emergency Response Program 2.0,

[3] 2015 Phase I, Hearing Ex. 7, Corrected Direct Testimony of Luke A. Litteken 15AL-0135G, page 24, line 19.

which includes hiring additional Gas Emergency Responders, Trouble Repair Positions and a supervisor. The overall goal of the Enhanced Emergency Response Program 2.0 is to further reduce our average response time and be able to respond to 90 percent of all emergency calls within 60 minutes by 2020.

For the MYP period, the Company proposes to hire 17 incremental Gas Emergency Responders as follows: two responders in 2018, four responders in 2019, and eleven responders in 2020.

Q. WHY IS THE COMPANY RECOMMENDING TO HIRE MORE GAS EMERGENCY RESPONDERS IN THIS PROCEEDING?

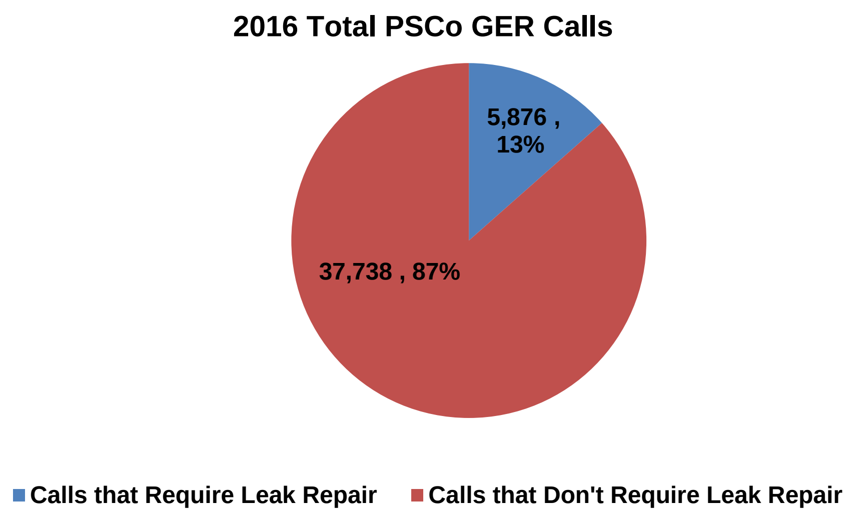
A. The Company responded to 73 percent of all gas emergency calls within 60 minutes in 2016 which represents fourth quartile performance according to AGA benchmarking survey results. Public Service believes that our customers demand safe, reliable natural gas service and responding to gas emergencies in a timely manner is critical to keeping customers and the public safe around our natural gas infrastructure. The Company has been actively working to maximize its performance with the limited resources that it has available to respond to more gas emergencies within 60 minutes. Public Service continues to evaluate and implement strategies to help new and existing employees improve efficiencies which include:

- allowing emergency responders who live in close proximity to the Company's service territory to take home emergency response vehicles,
- tracking productivity of individual responders and performing "ride-alongs" to more directly assist responders with identifying efficiency improvements,

- posting performance times for work groups to promote healthy "competition" between teams to drive productivity improvements across the work group,
- implementation of a review process for all orders taking longer than 60 minutes to identify barriers to responding more quickly, and
- participating in industry committees (AGA, Southern Gas Association ("SGA"), Midwest Energy Associations ("MEA")) to develop and benefit from industry best practices and strategies.

Additionally, the Company can reduce the amount of time an emergency responder needs to standby on the site of an emergency by increasing the number of trouble repair crews who respond to underground leaks requiring repair. Doing this will allow emergency responders more availability to respond to more emergency calls. It will also reduce the amount of overtime required for our repair crews to maintain system safety. As depicted in Figure LAL-D-4, Public Service received over 43,000 gas emergency calls in 2016, of which 13 percent required a leak repair.

Figure LAL-D-4, Total Public Service Calls



Utilizing peer benchmarking data, top quartile companies who respond to 98.83 percent of gas emergencies within 60 minutes have emergency responders who respond to an average of 145 emergency calls per year. Second quartile companies who respond to 97.4 percent of gas emergencies within 60 minutes have emergency responders who respond to 231 emergency calls per year and third quartile companies have 312 emergency calls per responder. Emergency responders in fourth quartile companies average 324 calls per responder. In 2016, Public Service averaged 454 calls per responder and responders in the Denver metro area averaged 661 calls per year placing Public Service in the fourth quartile.

Q. DOES THE COMPANY RECEIVE MORE CALLS PER CUSTOMER THAN ITS UTILITY PEERS?

A. Based on AGA benchmarking data, the total number of emergency calls the Company's responds to are near the industry average for calls per customer and calls per mile of main. As a natural gas operator we are required to have a Public Safety program that provides educational and awareness messages that encourage customers to call if they think they smell gas. Consequently, it is important to maintain the ability to respond to the volume of gas emergency calls that we receive each year.

Q. HOW DID THE COMPANY DERIVE HIRING 17 GAS EMERGENCY RESPONDERS?

A. In 2014, the Company responded to 60 percent of emergencies within 60 minutes. This increased to 73 percent in 2016 by hiring 12 emergency responders that were approved in the 2015 Phase I. This represents a 22 percent improvement. By having an incremental 17 emergency responders in place by 2020, the Company is forecasting to respond to 90 percent of all gas emergencies within 60 minutes. The Company expects its performance to improve to the third quartile in 2021 when the incremental 17 responders are fully productive. Table LAL-D-1 compares the actual number of emergency calls per responder in 2016 to the forecasted number of emergency calls per responder in 2020 with the incremental 17 gas emergency responders. The calls per responder goes from 661 emergency calls per year in 2016 down to 430 calls per responder by the end of 2020 or when the incremental 17 responders are fully productive, or a reduction of 35 percent.

Table LAL-D-1 Calls Per Responder – Denver Metro

	2016	2017	2018	2019	2020	2021
Total GER Calls (2016 YE Actuals)	28,444	28,444	28,444	28,444	28,444	28,444
FTE	43	49	51	55	66	66
Calls/Responder/ Year	661	580	558	517	430	430

Additionally, the Company believes it will be able to reduce overtime in the gas emergency response department as a result of hiring additional responders.

Q. WHAT OVERTIME REDUCTION HAS BEEN INCORPORATED IN THE MYP FOR GAS EMERGENCY RESPONSE?

A. The Company has reduced gas emergency response overtime in the MYP to account for the incremental hires. Table LAL- D-2 contains Denver Metro overtime reductions in the MYP period for gas emergency response. The table reflects overtime rates based on being fully staffed and the incremental responders are expected to be productive.

Table LAL- D-2 Gas Emergency Response Overtime Reductions Denver Metro Area[4]

	2016	**2017**	**2018**	**2019**	**2020**	**2021**
Overtime Hours	25,756	25,756	21,511	20,096	17,266	13,728
Overtime Dollars	$2,092,675	$2,092,675	$1,747,754	$1,632,781	$1,402,834	$1,115,400
Overtime %	28%	25%	20%	18%	13%	10%

The Company estimates that annual overtime rates will be reduced through the MYP from the current 28 percent to about 10 percent as a result of hiring additional gas emergency responders.

[4] In some instances, high gas emergency call volume may be associated to one event that over extend scheduled resources. Furthermore the scale of the event may have an adverse effect on response times for the operating company and the enterprise, examples of emergencies with a high impact to resources include but are not limited to, odorization events and spills, low pressure, gas outages, and severe weather events. If such a large scale event occurs, for purposes of the annual calculation, the company will average the response times of all related calls and treat it as one call for calculations of the annual response times metric.

Q. DOES THE COMPANY PLAN TO HIRE ANY OTHER POSITIONS AS PART OF THE ENHANCED EMERGENCY RESPONSE 2.0 PROGRAM?

A. Yes. In 2017, the Company proposes to hire four incremental trouble repair positions and one supervisor. These five positions have been added to the HTY. After the gas emergency responder makes the scene of an emergency safe by eliminating immediate hazards, such as blowing gas, a two-man trouble repair crew is dispatched to the scene if the responder is unable to repair the damaged facilities and reestablish service. The emergency responder must stay on-site until the repair crew arrives and takes over the scene. Increasing the number of repair crews will reduce the time emergency responders will need to stay on-site and make them more available to respond to other emergencies, which will help to reduce the Company's emergency response times. Also, overtime within the trouble repair department has averaged 40 percent over the last three years which is not sustainable. These additional repair positions will help reduce this overtime.

Q. WHY IS THE COMPANY RECOMMENDING HIRING FOUR TROUBLE REPAIR POSITIONS?

A. Over the last three years the trouble repair department has been working over 40 percent overtime. Overtime is expensive; a minimum of 1.5 times the standard hourly wage, and can lead to employee fatigue and ultimately employee injury. Table LAL-D-3 provides the annual overtime hours worked from the trouble repair department from 2014 to 2016. On average, each trouble repair employee worked 901-959 hours of overtime per year, equating to an overtime rate of over 43 percent - 46 percent.

Table LAL-D-3 Trouble Repair Department Overtime

	2014	**2015**	**2016**
Annual Overtime Hours	15,318	15,482	15,336
Trouble Repair Department Headcount	17	17	16
Average Annual Overtime Hours per Trouble Repair Personnel	901	911	959
Overtime Rate (%) per Trouble Repair Personnel	43%	44%	46%

Utilizing 2014 through 2016 data, with the hiring of four additional trouble repair personnel, the average trouble repair employee would have worked 333-351 hours per year or 16 percent - 17 percent. See Table LAL-D-4. This reduced amount of overtime is more sustainable for employees and is less expensive for our customers.

Table LAL-D-4 Forecasted Trouble Repair Department Overtime

	2014	**2015**	**2016**
Actual Annual Overtime Hours – Trouble Repair	15,318	15,482	15,336
Annual straight time Hours Per Year - Four Additional Trouble Department Employees	8,320	8,320	8,320
Remaining Annual Overtime Hours – Trouble Repair Department	6,998	7,162	7,016
Trouble Repair Department Headcount	17	17	16
Overtime per Trouble Repair Personnel	333	341	351
Overtime Rate	16%	16%	17%

Q. WHAT OVERTIME REDUCTION HAS BEEN INCORPORATED IN THE HTY FOR GAS TROUBLE REPAIR?

A. The Company has reduced trouble repair overtime in the HTY to account for the incremental hires. Overtime for the trouble department has been reduced by 8,320 hours or $675,964 in the HTY.

Q. WITH THE IMPLEMENTATION OF THE ENHANCED EMERGENCY RESPONSE PROGRAM 2.0, IS THE COMPANY PROPOSING TO UPDATE ITS PERFORMANCE METRIC OF AN AVERAGE RESPONSE TIME OF 60 MINUTES OR LESS?

A. Yes. Table LAL - D - 5 sets forth how Public Service will improve its performance responding to emergency calls with incremental hires proposed in the Enhanced Emergency Response Program 2.0.

Table LAL - D - 5[5]

Year	% within 60 minutes	Incremental annual hires
2017	78%	5
2018	83%	2
2019	85%	4
2020	88%	11
2021	92%	0
TOTAL		22

The Company's proposal is to modify the performance metric from average minutes to the percentage of emergencies responded to within 60 minutes to align with industry and Company standards.

Q. WHAT IS THE FORECASTED BUDGET FOR THE ENHANCED EMERGENCY RESPONSE PROGRAM 2.0?

A. For the MYP period, the forecasted Operations & Maintenance ("O&M") expenses are $356,893 for 2018, $795,847 for 2019, and $2,591,384 in 2020. This includes the costs for labor, tools, equipment, fleet, and employee expenses for the new positions and a reduction for overtime. These incremental O&M expenses are related to the 22 new positions required for the program. The Company is not including any incremental capital costs for the implementation of

[5] In some instances, high gas emergency call volume may be associated to one event that over extend scheduled resources. Furthermore the scale of the event may have an adverse effect on response times for the operating company and the enterprise, examples of emergencies with a high impact to resources include but are not limited to, odorization events and spills, low pressure, gas outages, and severe weather events.

the Enhanced Emergency Response Program 2.0 in this proceeding. Table LAL-D-6 Summary of GER Program Costs provides an overview of historical and future costs for the emergency response program.

Table LAL-D-6 Summary of GER Program Costs

GER 1.0	**2014**	**2015**	**2016**	**2016 HTY**	**2017**	**2018FTY**	**2019FTY**	**2020FTY**
Labor	$ 7,760,310	$ 8,757,731	$ 10,556,832	$ 11,870,900	$ 11,870,900	$ 12,350,485	$ 12,597,494	$ 12,849,444
Non-Labor	$ 1,959,176	$ 2,265,874	$ 3,359,131	$ 3,727,226	$ 3,727,226	$ 3,727,226	$ 3,727,226	$ 3,727,226
Total	$ 9,719,486	$ 11,023,605	$ 13,915,963	$ 15,598,127	$ 15,598,127	$ 16,077,711	$ 16,324,721	$ 16,576,670
Deferred			$ (2,162,035)		$ (3,844,198)			
Total	$ 9,719,486	$ 11,023,605	$ 11,753,928	$ 15,598,127	$ 11,753,928	$ 16,077,711	$ 16,324,721	$ 16,576,670
GER 2.0								
Labor				$ 875,557	$ 875,557	$ 1,299,654	$ 2,102,420	$ 4,194,852
Less OT				$ (675,958)	$ (675,958)	$ (1,020,857)	$ (1,480,723)	$ (2,170,521)
Non Labor				$ 55,912	$ 55,912	$ 78,096	$ 174,149	$ 567,053
Total				$ 255,511	$ 255,511	$ 356,893	$ 795,847	$ 2,591,384
Total GER	**$ 9,719,486**	**$ 11,023,605**	**$ 13,915,963**	**$ 15,853,637**	**$ 15,853,637**	**$ 16,434,604**	**$ 17,120,567**	**$ 19,168,055**

Q. IF THE COMMISSION DOES NOT APPROVE AN MYP, DOES THE COMPANY HAVE AN ALTERNATIVE PROPOSAL?

A. Yes. The Company proposes that the costs associated with the Enhanced Emergency Response Program 2.0 be deferred and a regulatory asset be established for these costs.

Q. WHAT DO YOU CONCLUDE REGARDING THE ENHANCED EMERGENCY RESPONSE PROGRAM AND THE PROPOSED UPDATED PROGRAM?

A. With respect to the deferred costs associated with the Enhanced Emergency Response Program that was approved in the 2015 Phase I, the Commission should allow the Company to amortize those costs over an 18 month period if an HTY is approved or if an MYP is approved be amortized over a 24 month period beginning on January 1, 2019 because Public Service has reduced its average response time to 60 minutes or less. Also, the Enhanced Emergency Response Program 2.0 should be approved to allow the Company to continue on its journey to responding to emergency calls quicker to ensure public safety. As depicted in Figure LAL-D-1, since 2014, the Company made significant improvements, reducing its average emergency response time by 30 percent. This program will continue to enhance public safety by providing the resources and staffing levels to respond to gas emergency calls in a more timely manner. Given the public safety impact, the related O&M expenses are reasonable.

III. DAMAGE PREVENTION PROGRAM

Q. ARE UNDERGROUND DAMAGES A SIGNIFICANT RISK TO PUBLIC SERVICE'S GAS DISTRIBUTION SYSTEM?

A. Yes. Damage to Public Service's underground facilities continues to be a significant risk to our gas distribution system. In fact, the second largest cause of leaks on Public Service's system has been third-party damage[6]. As a result, Public Service continues to institute a variety of outreach efforts to excavators regarding the importance of utilizing Colorado 811 as well as the Common Ground Alliance best excavation practices. It is critical that the Company's mains and services are located accurately before excavating to ensure safety for the workers as well as the public around the work site. Public Service re-evaluates its damage prevention programs to increase their effectiveness. The Company also participates in several industry organizations where it obtains and shares information about best practices for reducing public damage.

As a result of these efforts, Public Service continues to maintain our industry leading, top quartile position. A proactive and top quartile damage program also contributes to the Company's journey to improve response times to gas emergency calls that was started in 2015.

Attachment LAL-2 contains a graph that shows the number of damages per 1,000 locates from 2007 through 2016. As indicated by this graph, the

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[6] U.S. D.O.T. – PHMSA. Annual Report for Calendar Year 2016 Gas Distribution System – Public Service Company

Company has seen a 27 percent reduction in damages per 1,000 locates on our system since 2007.

Q. HOW HAS PUBLIC SERVICE RESPONDED TO THIS THREAT TO ITS GAS DISTRIBUTION SYSTEM?

A. Public Service implemented the Damage Prevention Program. The purpose of this program is two-fold. First, as part of the program, Public Service has implemented a “stand by and protect” procedure on high pressure and intermediate pressure pipelines in mid-2013. With this procedure, when a locate request involves these key pipelines, a Company representative will be on-site during the excavation. As a result, from 2014 to 2016, Public Service has seen a 44 percent reduction in damage to our intermediate and high pressure pipelines. This procedure reduces the risk of damage to these pipelines and the potential impact to the surrounding community by proactively preventing excavation damage.

Second, Public Service requires the companies with which we contract to perform locate requests to provide quality control and supervision in order to reduce mis-locates from their employees and further reduce overall damage caused by third party excavators to our underground assets.

Q. HOW ARE LOCATES PERFORMED BY PUBLIC SERVICE?

A. The Company utilizes several different contract outside vendors to perform locate requests. First, as noted above, the Company participates in Colorado 811, which provides a centralized phone center for customers to call to request locates. The Company is required to participate in Colorado 811 per Colorado Revised Statutes § 9-1.5-105 which fulfills federal mandate 49 CFR 198.37 requiring states with underground pipeline facilities to adopt a one-call damage prevention program. The cost for this service is free to customers; however, the Company pays Colorado 811 a cost per ticket. Second, the Company contracts with outside vendors to perform the actual production locates, specialty locates, and provide field support services. It is important to note that this work is bid out as part of a competitive bid process and the best vendor in terms of quality and cost is selected to perform the work.

Q. IN THE 2015 PHASE I, DID THE COMPANY PROPOSE A DEFERRED ACCOUNTING MECHANISM FOR THE LOCATE REQUESTS?

A. Yes. Because of increasing costs and the variability in locate requests from year to year, Public Service proposed (1) a pro forma adjustment to the HTY to account for escalating costs and (2) to defer the costs above the amount included in base rates and establish a regulatory asset for these additional costs. The Commission approved the Company's deferred accounting mechanism as damage prevention is an important part of public safety and the adjustment and cost deferral are reasonable. The total approved base amount is $11,497,794 for the 2014 HTY. See Decision No. R15-1204 and Proceeding No. 15AL-0135G Exhibit 3.

Q. WHAT WERE THE ACTUAL COSTS ASSOCIATED WITH THE LOCATE REQUESTS FOR EACH YEAR?

A. Attachment LAL-3 provides the actual O&M costs incurred for a three year period from 2013 through 2016. Over the same period, O&M costs have increased an average of 33 percent.

Q. HOW MUCH IS THE REGULATORY ASSET AS OF DECEMBER 31, 2016 AND THE FORECASTED AMOUNT FOR 2017?

A. As shown in Attachment LAL-4, Page 1 of 1, the balance of the regulatory asset at December 31, 2016 is $1,265,278 for the 2016 HTY. The forecasted balance of the regulatory asset for December 31, 2017 is $1,648,170. These O&M expenses are reasonable and should be recovered. Whether rates are approved in this proceeding based on an MYP for the period 2018 through 2020 or a 2016 HTY, Public Service requests that the deferred balances for 2016 and 2017 related to the regulatory asset for locate requests be amortized over an 18 month period if an HTY is approved or if an MYP is approved be amortized over a 24 month period beginning on January 1, 2019. Public Service witness Mr. Berman further discusses the amortization of the deferral balances related to the regulatory asset for locate requests.

Q. DOES THE VOLUME OF LOCATE REQUESTS CONTINUE TO REPRESENT A CHALLENGE FROM A SAFETY AND BUDGET PERSPECTIVE?

A. Yes. Attachment LAL-3 depicts the actual number of gas locate requests the Company has completed by year since 2013. The number of locate requests is driven by economic conditions in new construction and by local City, County, and State project activity. In fact, approximately 85 percent of locate requests are not Public Service projects at all, but other entities excavating around our infrastructure. This includes the Regional Transportation District's FasTracks, fiber, water and other underground infrastructure projects. As such, it is difficult to predict ticket volume on an annual basis. O&M expenses related to this type of locating requests vary considerably, depending on the requested work and its relation to the Company's key facilities.

Q. WHAT IS PUBLIC SERVICE'S PROPOSAL IN THE MYP FOR COSTS ASSOCIATED WITH LOCATE REQUESTS?

A. Public Service is proposing a continuation of the deferred accounting mechanism to account for these O&M costs. If a 2016 HTY or an MYP is approved, the Company proposes to (1) set the annual base O&M level at $12.8 million, which represents the total actual 2016 O&M expense of $11.5 million, plus the 2016 deferred balance of $1.3 million; (2) amortize the 2016 and 2017 deferral balances of $1.3 million and $1.6 million over an 18 month period if an HTY is approved or if an MYP is approved be amortize these costs over a 24 month period beginning on January 1, 2019; and (3) defer the costs incurred above or below the base amount and establish a regulatory asset for such costs. These O&M expenses are reasonable. For a discussion of the deferred accounting mechanism, see the Direct Testimony of Public Service witness Mr. Berman.

IV. SCADA/GAS CONTROL MONITORING IMPROVEMENT PROGRAM

Q. WHAT IS SCADA?

A. The SCADA system collects data and sends information from remote metering and monitoring points to our Gas Control computer systems. Company personnel monitor the incoming data and information about the system including system pressures, flow rates, and valve positions. The purpose of the SCADA system is to remotely monitor and control the flow of natural gas into and throughout our transmission and distribution systems. Based on information received through SCADA, Gas Controllers, monitoring gas operations 24 hours a day, seven days a week can identify problems (*e.g.,* pressure drops/surges and gas flow rates) as they arise and can dispatch field personnel proactively to prevent potentially catastrophic events.

Q. DID THE COMPANY PROPOSE A SCADA/GAS CONTROL MONITORING IMPROVEMENT PROGRAM IN THE 2015 PHASE I?

A. Yes. In the 2015 Phase I, Public Service proposed to increase the number of SCADA pressure monitoring points from regulators stations and other strategic locations on our gas transmission and distribution systems. The proposed program entailed the installation of approximately 1,100 additional pressure monitoring devices over a three year period.

Q. DID THE COMMISSION APPROVE THE COMPANY'S PROPOSAL IN THE 2015 PHASE I?

A. The Administrative Law Judge's ("ALJ") Recommended Decision originally denied Public Service's request for a pro forma adjustment to the 2014 HTY for its proposed SCADA/Gas Monitoring Program. See 2015 Phase I, Decision No. R15-1204 at 61-62. However, the Commission reversed the Recommend Decision and approved of the pro forma adjustments of $1.7 million to the 2014 Test Year.[7] Specifically, the Commission stated that "Public Service is not barred from future cost recovery of SCADA project costs incurred in the ordinary course of business." Additionally, the Commission state that the "ALJ properly determined that the Company's qualitative analysis for the proposed project was inadequate" and the Company "must conduct a thorough quantitative cost benefit analysis for project justification for future cost recovery of any additional upgrades." See 2015 Phase I, Decision No. C16-0123 at 24.

Q. DID THE COMPANY IMPLEMENT THE SCADA/GAS CONTROL MONITORING IMPROVEMENT PROGRAM IN THE ORDINARY COURSE OF BUSINESS?

A. At the time of the 2015 Phase I filing, the Company had approximately 350 SCADA monitoring points deployed across Public Service's gas system. Since 2014, the Company has pursued this program within the ordinary course of

[7] Proceeding No. 15AL-0135G, Decision No. C16-0123

business and has installed approximately 700 additional SCADA monitoring points at a cost of approximately $5.1 million, or $7,334 per unit which is similar to the estimated cost of $7,500 per unit from the 2015 Phase I.

Additionally, the Company has hired two Gas Controllers and two Gas Operations Technical Specialist ("GOTS") positions to support the Company's SCADA system. The additional Gas Controllers were hired to support the incremental electronic monitoring points, ensuring adequate coverage in Gas Control 24/7 without violating any regulations about alarm trends. The GOTS were hired to provide installation, inspection, maintenance and repair for the incremental SCADA points. Based on information received through SCADA, Gas Controllers can identify problems (*e.g.,* drops and/or surges in pressure) as they arise and dispatch field personnel proactively to prevent and/or lessen events. Please refer to the Direct Testimony of Cheryl Campbell for additional detail regarding the O&M expenses related to the additional GOTS and Gas Controllers.

Q. AS ORDERED BY THE COMMISSION, DID THE COMPANY PERFORM A COST BENEFIT ANALYSIS FOR THE SCADA/GAS CONTROL MONITORING IMPROVEMENT PROGRAM.

A. Yes, the Company originally performed a cost benefit analysis of the program in 2013 as part of the well-defined, nine step, capital funding process discussed in the Direct Testimony of Witness Cheryl Campbell. Within the capital budgeting process, the Company performs a cost benefit analysis for all projects wherein the capital and O&M costs of a proposed project are weighed against the consequences, benefits, and avoided costs of not pursuing the project. This analysis is performed in a Company system known as “Workbook”. The results of the cost benefit analysis performed in Workbook in 2013 was a risk score of 2.1 meaning the benefits of implementing the program outweighed the costs.

Q. DID THE COMPANY REFRESH THE 2013 COSTS BENEFIT ANALYSIS IN PREPARATION OF PREPARING FOR THIS RATE PROCEEDING?

A. Yes, the Company refreshed its Workbook analysis with actual costs and known benefits. In the 2016 HTY, the Company identified seven significant events in which Gas Control personnel prevented a potentially catastrophic event based on information from the SCADA system. In total, the Company estimates that had Gas Control personnel not proactively responded to system issues these seven events could have resulted in over 14,000 customer outages across Public Service’s system. Attachment LAL-5 provides a list of these seven significant events and the corresponding number of avoided customer outages. The results of the cost benefit analysis performed in Workbook with the actual costs and the benefit of over 14,000 avoided customer outages was a risk score of 15.6. Attachment LAL-6 provides an overview of the cost benefit analysis. Given the high risk to public safety inherent in outage events, the result of the analysis is a positive cost benefit.

Q. IS SCADA REQUIRED BY REGULATION?

A. As discussed in the 2015 Phase I, SCADA systems are a key element to the identification of abnormal pipeline operating conditions and the prevention or mitigation of the consequences of a pipeline failure. Furthermore, these systems are necessary for the safe and reliable operation of our gas transmission and distribution systems as required by Federal Regulation.

In the 2015 Phase I, the Company provided examples of how SCADA monitoring has or could have impacted outage events in the past. As an additional example, on July 25, 2010 a segment of a 30-inch diameter pipeline, owned and operated by Enbridge Incorporated, ruptured in a wetland near Marshall, Michigan. The rupture was not discovered or addressed for over 17 hours. Enbridge was fined over $62 million and cleanup and remediation costs, exceeding over $1 billion. Following the incident, the Pipeline and Hazardous Materials Safety Administration ("PHMSA") released an Advisory Bulletin encouraging operators of gas transmission and hazardous liquid pipelines to "evaluate their leak detection capabilities to ensure adequate leak detection coverage during transient operations and assess the performance of their leak detection systems following a product release to identify and implement improvements as appropriate.[8]" The Federal Pipeline Safety rules (49 Code of Federal Regulations 192.935) require that operators determine and implement

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[8] https://www.phmsa.dot.gov/staticfiles/PHMSA/DownloadableFiles/Advisory%20Notices/AB_79_FR_25990_5-6-14.pdf

measures to prevent a pipeline failure or mitigate the consequences of such a failure. These measures may include, but are not limited to, installation of automatic shut-off valves, remote control valves, additional inspection and maintenance programs, and installation of system monitoring equipment and SCADA systems. These measures are intended to provide earlier leak or pipeline rupture detection. As referenced in PHMSA Advisory Bulletin ADB-99-03, during an Office of Pipeline Safety ("OPS") investigation of a pipeline incident, OPS inspectors identified inadequate SCADA performance as an operational safety concern. The Advisory Bulletin states that "Each pipeline operator should review the capacity of its SCADA system to ensure that the system has resources to accommodate normal and abnormal operations on its pipeline system."

Q. WHAT IS THE IMPACT OF THIS PROGRAM DURING THE MYP PERIOD?

A. Based on the positive result of the cost benefit analysis, the Company is proposing to install approximately 400 more SCADA monitoring points in 2019 for an estimated capital cost of approximately $2.1 million. The Company proposes to continue managing the future capital costs incurred for this project within the ordinary course of business with funding to be allocated as a result of the risk ranking methodology used for all capital projects. The Company does not plan to incur additional O&M expenses for this program during the MYP period.

Q. WHAT DO YOU CONCLUDE REGARDING THE SCADA / GAS CONTROL MONITORING IMPROVEMENT PROGRAM?

A. The SCADA system has proven to be an effective and necessary tool that is vital to the safe and reliable operation of the system. This program should be approved as the related investment has been prudently incurred, is reasonable in cost, and the related O&M expenses are also prudent and reasonable. This program has not only enhanced the safety and reliability of Public Service's system but it has also preserved and improved customer service.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Statement of Qualifications

Luke A. Litteken

I received a Bachelor of Arts in Business Administration and a Master of Business Administration from Augsburg College. I have an Associate of Technology in Heating, Cooling and Refrigeration from Ranken Technical Institute in St. Louis, Missouri. I also hold the following professional licenses: Master Gasfitter license, Master Refrigeration license, and Master Warm Air license.

I was hired by CenterPoint Energy ("CNP") as a Service Technician in the Field Operations Department in 1989 and was promoted to Supervisor, Field Operations in 1995. I was responsible for a team of emergency responders and service technicians for a geographic territory in Minnesota.

In 2000, I became Manager of Subcontractor Services & Sales Administration for CNP. In this position, I developed the credit policy, credit administration, records retention, and sales administration to support the retail sales business. I also developed and implemented the processes to rollout the SAP business platform for CNP's Home Service Plus retail sales business.

From 2005 to 2009, I was promoted to Manager of Field Operations in Minnesota for CNP. In this position, in addition to managing CNP's Field Operations, I negotiated non-union and union subcontractor agreements, led the team that worked on reducing bad debts, and co-led the Minnesota CNP Emergency Response team that focused on the promptness and efficiencies of CNP's emergency responses.

From 2009 until the time that I joined XES in 2014, I served as Director of CNP's South District and North District. In this position, in addition to overseeing the provision of safe and reliable service to approximately 400,000 customers, my responsibilities included emergency response, community relations, franchise negotiations, new customer growth and the development of district budgets. I also acted as incident commander for several significant CNP gas events. I led the efforts that improved emergency response times for second responders. Further, I led the team that developed common processes and identified best practices across CNP's jurisdictions.

In 2014, I joined XES as Area Vice President, Gas Operations. In this position, I have oversight of the operations and maintenance of the gas distribution and high-pressure systems in the seven states in which Xcel Energy operates[9], including gas control center operations. My responsibilities include system reliability, emergency response, damage prevention and compliance with federal and state rules and regulations. I also provide leadership over Xcel Energy's gas operations including bargaining and non-bargaining employees, contractors and other outside vendors.

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[9] Xcel Energy's gas operations are in Colorado, Michigan, Minnesota, North Dakota, South Dakota, Texas, and Wisconsin.

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

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RE: IN THE MATTER OF ADVICE LETTER NO. 912-GAS FILED BY PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC NO. 6-GAS TARIFF TO IMPLEMENT A GENERAL RATE SCHEDULE ADJUSTMENT AND OTHER RATE CHANGES EFFECTIVE ON 30-DAYS NOTICE.	**)))))))**	**PROCEEDING NO. 17AL-____G**

AFFIDAVIT OF LUKE A. LITTEKEN PUBLIC SERVICE COMPANY OF COLORADO

I, Luke A. Litteken, being duly sworn, state that the Direct Testimony and attachments were prepared by me or under my supervision, control, and direction; that the Testimony and attachments are true and correct to the best of my information, knowledge and belief; and that I would give the same testimony orally and would present the same attachments if asked under oath.

Dated at Denver, Colorado, this twenty-sixth day of May 2017.

Luke A. Litteken

Luke A. Litteken
Area Vice President, Gas Operation

Subscribed and sworn to before me this 26TH day of MAY, 2017.

DIANE K DURESKY
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID # 20064044236
MY COMMISSION EXPIRES NOVEMBER 22, 2018

Diane K Duresky

Notary Public

My Commission expires NOVEMBER 22, 2018