Integrating Leak Quantification into Natural Gas Utility Operations

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Abstract

Natural gas utilities can incorporate leak flow rate data into existing pipeline replacement and leak repair prioritization frameworks to more rapidly and efficiently reduce leakage on their system. Leak distributions typically demonstrate a "fat-tail," where a few, large leaks are responsible for the majority of lost gas volumes. Through ranking and ordering leak flow rate data, utilities can identify a subset of the largest leaks to repair or the leakiest pipelines to replace, and capture more gas per dollar spent on leak repair or pipeline replacement. This benefits ratepayers, who pay for the cost of lost gas, and also carries broader environmental and societal benefits.

1. Introduction

Studies of natural gas distribution pipeline leaks indicate that a relatively small subset of leaks is responsible for a disproportionate share of total observed emissions (Brandt et al., 2016; Lamb et al., 2015; Hendrick et al., 2016; von Fischer et al., 2017). Even though natural gas distribution utilities must expeditiously repair hazardous leaks, many large leaks can persist for months or years prior to repair because the standard used to grade a leak's risk generally places greater weight on the proximity to structures than to leak size. Recently, mobile monitoring has been used to detect the presence of underground pipeline leaks and estimate their size (von Fischer et al., 2017). If utilities used such leak quantification systems to prioritize abatement of the largest non-hazardous leaks, after taking safety into account, the climate benefits of leak repair and pipe replacement programs could be enhanced. By eliminating more natural gas losses per dollar spent on leak repair and pipeline replacement, leak quantification also helps constrain ratepayer costs.

Information on the size of leaks can also help utilities to verify and validate the need for leak repair and pipe replacement programs and allow regulatory agencies responsible for authorizing utility leak abatement projects to better assess the need for such efforts. In addition, leak quantification can improve project management by allowing utilities and public utility commissions to evaluate the progress of leak repair and pipeline replacement programs by considering the reduction in volumes of leaked gas achieved through implementation of such programs. This paper describes the implications of integrating leak quantification into utilities' regular leak operations and explores potential frameworks for implementation based on currently employed utility practices.

2. Leak Repair and Pipeline Replacement Programs: Current Regulatory Framework and Utility Practice

Natural gas leaks and leak-prone infrastructure impose costs and pose safety risks to society. Natural gas leaks are also harmful to the climate and environment because they consist primarily of methane, a potent short-lived climate pollutant and an ozone smog precursor. Traditionally, local gas distribution utilities focus their repair programs on finding, assessing, and repairing leaks in their infrastructure to prevent explosions. The occurrence of pipeline leaks is influenced by the following factors (U.S. Department of Transportation, 2011; American Gas Foundation and Yardley Associates, 2012):

- Exposure to extreme weather (e.g. temperature, moisture),
- Corrodible or brittle pipeline materials (cast iron, bare steel, copper, and certain vintage plastic pipes),
- Age,
- High occurrence of joints,
- Material or weld failures,
- Location of pipeline in the vicinity of excavation, or
- Areas where soil is unstable (e.g. earthquake-prone areas, karst-prone systems or in shrink/swell soils).

The Pipeline and Hazardous Materials Safety Administration (PHMSA) rules require operators to annually report data on the number of leaks repaired and the number of known leaks remaining on their system at the end of each year, but do not require operators to quantify leak volume (49 C.F.R. §191.11 and Form PHMSA F 7100.1-1).

PHMSA also offers non-binding guidance to operators on how to grade leaks based on safety risk, thereby establishing leak repair priority, and assisting operators in complying with federal safety rules that require them to "evaluate and rank risk" posed by their distribution pipeline systems (49 C.F.R. § 192.1007). Some states have incorporated or adapted PHMSA's leak grading guidance into their rules and statutes (NAPSR, 2013). The grading categories are based solely on an evaluation of the risk to persons or property and primarily considers proximity to building envelopes (PHMSA, 2000). Moreover, some researchers have observed the size, or leak flow rate, of grade one (i.e. "immediately" hazardous) leaks to be no different from other grades of leaks (Hendrick et al., 2016). Under the existing regulatory framework, utilities are generally not required to repair non-hazardous leaks (i.e. leaks that are not immediately hazardous) within a specific timeframe. As a result, non-hazardous leaks may continue unabated for long periods, in some cases decades,[1] thereby wasting a valuable resource and hurting the economic interests of ratepayers, who bear the costs of leaked gas.

[1] Two jurisdictions in the U.S., California and Massachusetts, require gas distribution utilities to report leak inventories with relevant characteristics. Leak data made available through the California Public Utilities Commission R. 15-01-008 – Natural Gas Leakage Abatement Rulemaking indicates that as of May 22, 2015, there were some leaks discovered in the 1990s that still had not been scheduled for repair.

PHMSA guidance on leak grading suggests comparing the concentration of gas in air around the leak to the lower explosive limit (LEL) of natural gas. [2] However, methane concentrations in air (e.g. parts per million) in and around a leak are not necessarily proportional to the rate at which gas is being lost (i.e. flow rate, typically measured in standard cubic feet per hour). Current utility practices, therefore, are insufficient for: (1) prioritizing leak repair using flow rate, or (2) verifying the effectiveness of leak repair and pipeline replacement initiatives at reducing system-wide losses of methane from natural gas.

It is important to distinguish between leak repairs, which occur on a regular basis and are paid for through operation and maintenance budgets, and pipeline replacements. On average leak repairs cost from $2,000 to $7,000 per leak (Aubuchon and Hibbard, 2013; Pacific Gas and Electric Company, 2015a). Considering that utilities are required to repair hazardous leaks immediately while non-hazardous leaks can persist for longer periods of time, leak quantification can be used to prioritize non-hazardous leaks for repair, thus improving cost-effectiveness by capturing the highest volumes of gas per dollar spent on leak repair without negatively impacting safety.

Similarly, leak quantification can be used to prioritize pipelines for replacement. Pipeline replacement can cost between $900,000 and $3 million per mile of pipe depending on a variety of factors (Aubuchon and Hibbard, 2013; Anderson et al., 2014). Utilities across the country are looking to replace many, if not most, of the 70,000 miles of leak-prone distribution pipes still in operation in the U.S. over the next two decades at an estimated cost of $270 billion (U.S. Department of Energy, 2015).[3]

The size of these investments underscores the need to thoughtfully design and execute these programs. In order to prioritize leak repair and pipe replacement programs, many utilities use hazard assessment algorithms to estimate the relative safety risk posed by leaks on their system, considering factors such as pipe material, environmental conditions, leak history, etc. After hazard assessment data is considered, leak flow rate data provides additional information that can be considered in prioritizing leak repair and pipeline replacement activities, and by so doing optimize the benefits of both operating and capital expenses.[4] Typical utility practices do not include leak flow rate assessments and therefore do not allow for this kind of improved prioritization.

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[2] The PHMSA guidance document, "Gas Leakage Control Guidelines for Petroleum Gas Systems," gives several examples of a Grade 1 leak:

- *Any leak which, in the judgment of operating personnel at the scene, is regarded as an immediate hazard*
- *Escaping gas that has ignited*
- *Any reading of 80% LEL or greater in a confined space*
- *Any reading of 80% LEL or greater in small substructures (other than gas associated substructures) from which gas would likely migrate to the outside wall of a building*

[3] The estimated 70,000 miles of leak-prone pipe includes cast iron, unprotected bare steel, copper, ductile iron, and "other," as listed in PHMSA 2015 Annual Distribution Data. Cost estimates provided from the U.S. Department of Energy (2015) may be based on older mileage values, and it is unclear which materials are included in the U.S. Department of Energy's estimate.

[4] The availability of additional data points indicating the character of pipeline infrastructure is naturally useful for the purposes of integrity management as well. Utilities may find that it is beneficial to integrate leak flow rate values into hazard assessments.

3. Benefits of Using Leak Quantification

In 2011, PHMSA issued a "Call to Action" to state pipeline regulatory agencies, pipeline operators, and technical and subject matter experts after a series of natural gas distribution pipeline explosions. Recognizing the safety risks associated with cast iron gas mains, PHMSA urged state agencies to facilitate accelerated pipeline replacement programs for cast iron and other high-risk pipeline segments (U.S. Department of Transportation, 2011). Accelerated pipeline replacement programs are necessary from a safety standpoint, but also carry significant ratepayer and environmental implications.

With advanced leak detection technology and leak quantification, a utility can quickly and comprehensively assess the leakiness of its infrastructure with geospatial awareness. Using leak flow volume to further prioritize leak repair and pipeline replacement programs, once safety considerations have been taken into account, offers benefits to both ratepayers and society as a whole. First, the larger reductions in lost gas that leak prioritization can achieve translates into savings for ratepayers who generally pay both for gas delivered as well as gas lost on the pipeline system, which is considered an accepted cost of service (Webb, 2015). Second, there are societal benefits from reducing the amount of gas leaked because natural gas is composed primarily of methane,[5] a powerful short-lived climate forcer 84 times more potent than carbon dioxide over a 20-year time horizon (IPCC, 2013).

Researchers have estimated the social costs of greenhouse gas emissions by considering their effect on the climate and subsequent impacts such as changes in agricultural productivity, heat-related illness, and property damages from increased flood risk. The social cost of methane is a monetized value of the damages occurring as the result of an additional unit of methane emissions. Specifically, it represents society's aggregate willingness to pay to avoid the future impacts of one additional unit of methane emitted into the atmosphere in a particular year (Martens et al., 2014). Estimates of the social cost of methane can be used in a cost-benefit analysis of proposed regulations or projects with an impact on methane emissions. That is, the social cost of methane can be used to assess the benefits to society of a leak repair or a pipeline replacement program. The estimate for the social cost of methane used by federal agencies to value the climate impacts of new rulemakings is $1000/ton of methane (Interagency Working Group on Social Cost of Greenhouse Gases, 2016).[6] This estimate translates into social damages of $17 per thousand cubic feet (Mcf) of natural gas leaked and hence each reduced Mcf of gas leaked to the atmosphere spares society as much in climate change-related damages.[7]

4. Using Leak Quantification to Prioritize Pipe Replacement and Leak Repair

Studies show that distributions of leaks often exhibit a "fat-tail," where a small number of large leaks, often referred to as superemitters, account for the majority of measured gas losses in a sample (Brandt et al., 2016; Lamb et al., 2015; von Fischer et al., 2017). Leak quantification can help utilities facilitate cost-effective design and implementation of leak repair and pipe replacement programs by allowing for

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[5] On average, pipeline-quality natural gas is composed of over 90% methane by volume (Demirbas, 2010).

[6] This specific estimate refers to the damages associated with a ton of methane emitted in 2015 monetized in 2007 dollars. The current value therefore would be higher when adjusted for inflation. The value is also higher for emissions in later years because future emissions are expected to produce larger incremental damages (see Interagency Working Group on Social Cost of Greenhouse Gases, 2016).

[7] Assuming a mass of 19,200 g/Mcf natural gas, and a methane share of 78.8% per mass unit of natural gas. This estimate is in $2007 for one Mcf of natural gas leaked in 2015.

prioritization of the highest-emitting leaks or pipe segments, as the case may be. The methodology also allows public utility commissions to consider the need for, and progress of, the planned program.

4.1 Information that improves efficiency

Utilities are starting to adopt the use of advanced leak detection equipment capable of finding more leaks more rapidly. For example, the California Public Utilities Commission reports that utilities experienced a 21% increase in the number of leaks detected from 2013 to 2014, due partly to the use of advanced leak detection technologies (Mrowka et al., 2016). Additionally, the use of advanced leak detection technology has been shown to reduce the time needed to complete a leak survey, have a longer-distance field of view for detecting leaks, and can be used overnight when atmospheric conditions are more stable (Clark et al., 2012).

Applied efficiently, advanced leak detection technology can be used to obtain (on a continuous basis) leak information sufficient for determining the most hazardous and/or largest emitting leaks that in turn can be prioritized for remediation. Rather than continuing the paradigm that leaks are found and remediated one at a time, industry and regulators can foster innovative strategies that involve obtaining leak survey information as the first step, and application of advanced analytics as a second step, in order to prioritize remediation of the most hazardous and largest leaks.

4.2 Leak repair and pipe replacement prioritization methodology

One key consideration in employing leak quantification methodologies to leak repair programs is how to systematically translate a database of measured leak flow rates into a prioritized list. This consideration is equally applicable to pipe replacement programs, where the corresponding challenge is to prioritize pipeline segments for replacement. In providing the data necessary, the primary emphasis should not be on the accuracy of individual leak measurements, but rather on the precision of the characterization of the leaks, the ability to provide a prioritized list and a cost-effective path to reducing leak volumes.

A cumulative distribution, ordering leaks by size, is a useful tool to determine the relative priority of leaks for repair, which is made possible with the use of sufficiently precise leak quantification methodologies. A cumulative distribution can both help identify the largest leaks, and determine their relative contribution to overall leakage.

As shown in Figure 1 (A), the flow rate of leaks can vary significantly. When ranked from largest to smallest as shown in Figure 1 (B), the relative importance of different leaks is transparent and the relative contribution of each leak to overall leak flow rate is easily quantified (Figure 1 [C]). The cumulative distribution is created by integrating the ranked distribution in Figure 1 (B) from left to right. The first data point from the left on the X-axis in the CD plot is the leak determined to have the largest leak volume, the second point is the cumulative leak flow rate of the top two leaks, the third point is the sum of leak flow rates of the top three leaks, and so on. Thus, the last data point is the sum of leak flow rates of all known leaks. This distribution is then normalized to 1 (or 100% in Figure 1 [C]) so that we can readily consider the relative contribution of a certain number of leaks to the total system-wide leakage.

While this discussion focuses on the particular context of leak repair, a similar analytical approach can be applied to prioritize pipeline segments for replacement (see Appendix).

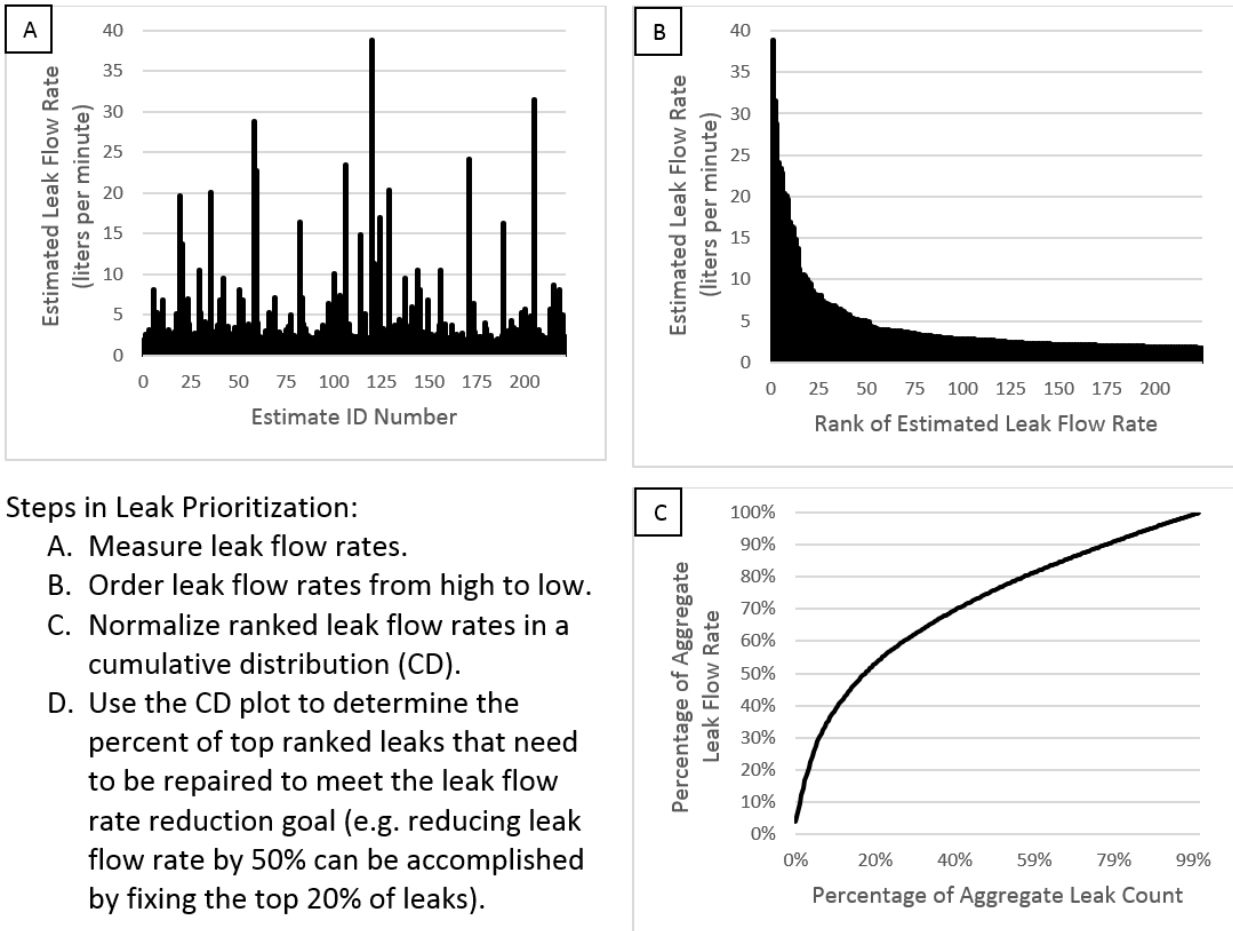

Figure 1 An example step-by-step model depicts how to construct a cumulative distribution curve for the purpose of leak prioritization, using data collected by EDF in Syracuse, NY.

In the near term, leak quantification can help utilities reduce the volumes of gas lost through leakage, and thereby save ratepayers money and reduce methane emissions, by enabling the prioritization of both leak repair and leak-prone pipeline replacement projects based on leak flow rate. In the longer term, as leak quantification methodologies become more sophisticated, utilities will be able to easily quantify leak rates for their entire system, measuring progress in reducing emissions.

In the context of leak repair programs, leak volume may be considered to prioritize the repair of non-hazardous leaks, with the utility addressing larger leaks first. Similarly, in the context of leak-prone pipe replacement, a utility may prioritize the leakiest pipeline segments on its system for replacement first. In either case, as discussed below, utilities are starting to recognize the benefits of a "bundling" or "grid-based" approach whereby leaks or pipeline segments in a given geographic area are bundled together for repair or replacement, as the case may be, in order to allow for efficient use of time and resources (Clark et al., 2012).

5. Case Studies: Applying Leak Quantification Data to Utility Operations

Using leak data collected by Environmental Defense Fund (EDF), Public Service Gas & Electric (PSE&G), New Jersey's largest utility, is applying a spatially-attributed grid-based method to prioritize pipe

segments for replacement. This effort is part of a large-scale $905 million pipe replacement program that was recently approved by the New Jersey Board of Public Utilities (Public Service Electric and Gas, 2012). The methodology developed by EDF in collaboration with PSE&G is discussed below.

First, PSE&G's distribution system was plotted using geographic information systems (GIS) divided into roughly equally sized polygons of one square mile. Using its Hazard Risk Index Model, PSE&G ranked grids for pipeline replacement based on the hazard index per mile of cast iron pipes in each grid, which is calculated based on an assessment of safety risk factors.[8] The hazard index per mile for each grid for which EDF quantified leak flow rate is depicted in Table 1 of the Appendix.

Next, using a Google Street View car equipped with methane detection equipment and geographic positioning systems (GPS), EDF surveyed 30 grids targeted for pipe replacement based on their ranking by the Hazard Risk Index Model. A leak quantification algorithm developed by Colorado State University was applied to the resulting data such that the leak flow rate for each leak observed was calculated (von Fischer et al., 2017). Flow rates for all leaks detected in a given grid were then summed and averaged over the number of miles of pipe in each grid to arrive at the estimated leak flow rate per mile of pipe in each grid. The resulting normalized metric resulted in a ranking of grids by their leak flow rate per mile of pipe (Table 1 of the Appendix).

This methodology was used to develop spatially attributed leak data for each grid cell (Figure 2),[9] presenting a visual depiction of the relative size, frequency, and location of leaks in each grid cell, and attributing each leak to particular segments of utility infrastructure. This information when sorted by comparable Hazard Risk Index results, used in making the initial prioritization of the grids, allowed PSE&G to prioritize grids for pipeline replacement. Specifically, for grids with comparable hazard ranks, the overall leak flow rate/mile of pipe was considered to identify and prioritize the leakier grids for replacement.

PSE&G's approach allowed it to focus its expenditures and resources on the leakiest pipeline segments and also recover the largest volume of usable natural gas per section of pipeline replaced. An analysis of emission reductions from PSE&G's final prioritized grid replacement strategy indicated that PSE&G was able to control 83% of the measured leak flow rate by replacing 58% of the pipeline mileage in measured grids (Appendix, Table 1 at grid 2B-42). In the business-as-usual case, PSE&G would have needed to replace 99% of the pipeline mileage in the surveyed grids to reach the same level of emission reductions (Appendix, Table 2 at grid 2C-43). Therefore, PSE&G achieved an 83% reduction in leak flow rate by replacing approximately one-third fewer miles of pipe than would have been necessary to achieve the same level of emission reductions if they had not used leak flow rate data. All of the pipes

[8] PSE&G conducts an annual study using this model to evaluate each cast iron main segment that has had a break, to rank each segment for replacement based on a combination of break history and environmental factors. Each geographic grid is ranked by adding the hazard indexes for individual pipe segments within the geographic grid and dividing them by the total miles of utilization pressure cast iron (UPCI) in the grid, arriving at a hazard index per mile for each geographic grid. Using the hazard index per mile results, grids were ranked by highest to lowest and then placed into A, B, C, and D priority grid categories.

[9] PSE&G's infrastructure data is protected under a non-disclosure agreement, and is not shown here. However, an example of the grid method, using fictitious data, is provided in Figure 2.

targeted for replacement will eventually be replaced, but emission reductions were achieved sooner than they would have been in a business-as-usual scenario.

Cast iron pipelines make up roughly 4% of pipelines nationwide. The avoided leak rates assumed here are based on roughly 9% of cast iron pipeline mileage having been prioritized for replacement out of the PSE&G miles where leak flow rates were quantified. In the case of PSE&G, those 9% of cast iron pipeline miles were equivalent to 37% of the estimated leak flow rate. Let us assume that utilities across the nation find and replace superemitting pipeline segments in a similar proportion to PSE&G — that is, where the prioritized grids represent 37% of the measured emissions and 9% of the pipeline miles. If this is possible, then 37% of emissions would be reduced by prioritizing 9% of nationwide cast iron pipeline miles, or roughly 2,500 miles. Reducing 37% of national cast iron pipeline emissions would be equal to reductions of 600,000 Mcf/year (+/- 70,000 Mcf/year).[10] This would have the same climate impact as taking 200,000 passenger vehicles off the road each year (+/-24,000 passenger vehicles).[11]

There are of course, uncertainties in the proportional presence of superemitting pipeline segments, the actual leak flow rates of those segments, and whether superemitting pipeline segments would be coincidentally classified as hazardous, regardless of leak flow rate. Even in PSE&G's system, the frequency of superemitters is unknown on a system-wide basis, because only some areas were surveyed, and because little is known about the "birth rate" of superemitters on a system. Nonetheless, these results from PSE&G indicate that there are likely to be sizeable benefits of leak quantification and prioritization for the climate and ratepayers.

PSE&G is already beginning to capture the benefits of prioritizing high-emitting (or "superemitting") grids for replacement. If other utilities find and prioritize superemitting pipeline segments or leaks at a similar rate nationwide, significant climate benefits could be achieved earlier than might otherwise be possible under a business as usual efforts.

As mentioned above, the grid approach can also be used to prioritize geographic zones not only for pipeline replacement, but also for leak repair. In 2015, Consolidated Edison of New York (CECONY) had the highest percentage of leak prone pipeline mains out of any utility in New York.[12] Just as PSE&G is using leak quantification to prioritize pipeline segments for replacement, CECONY recently completed a pilot program in collaboration with EDF to prioritize the utility's non-hazardous leaks for repair (Environmental Defense Fund and Consolidated Edison Company of New York, 2016). CECONY provided EDF with location and infrastructure information for its non-hazardous leak backlog. EDF surveyed the areas indicated by CECONY and quantified these leaks. CECONY will rank and prioritize leaks for repair based on the emissions flow volume. Preliminary results show that more than half of the emissions identified through our survey efforts could be eliminated by addressing the largest 18% of the leaks.

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[10] This estimate only includes the removal of cast iron pipelines. The calculation of potential reductions of national cast iron pipeline emissions is derived by multiplying the average emission factor of 60.1 Mcf/mile/year for cast iron by the total miles of cast iron in the nation and multiplying that product by 37%. The estimate does not account for the added potential emissions of plastic mains — the most likely replacement material — which have an estimated average emission factor of 0.5 Mcf/mile/year (Lamb et al., 2015; U.S. Environmental Protection Agency, 2016).

[11] Assuming a 20-year Global Warming Potential of 84 for methane.

[12] "Leak prone pipeline mains" includes miles of unprotected bare steel mains and cast iron mains.

By enabling the ranking of the leakiest pipeline segments and individual leaks, leak quantification can help utilities decide where to repair leaks or replace pipelines when comparing sections of infrastructure with comparable risk rankings, thereby balancing safety and efficiency considerations. This approach, now pioneered by two major utilities, presents significant safety, capital efficiency, ratepayer, and environmental benefits, and is ready for adoption by other utilities.

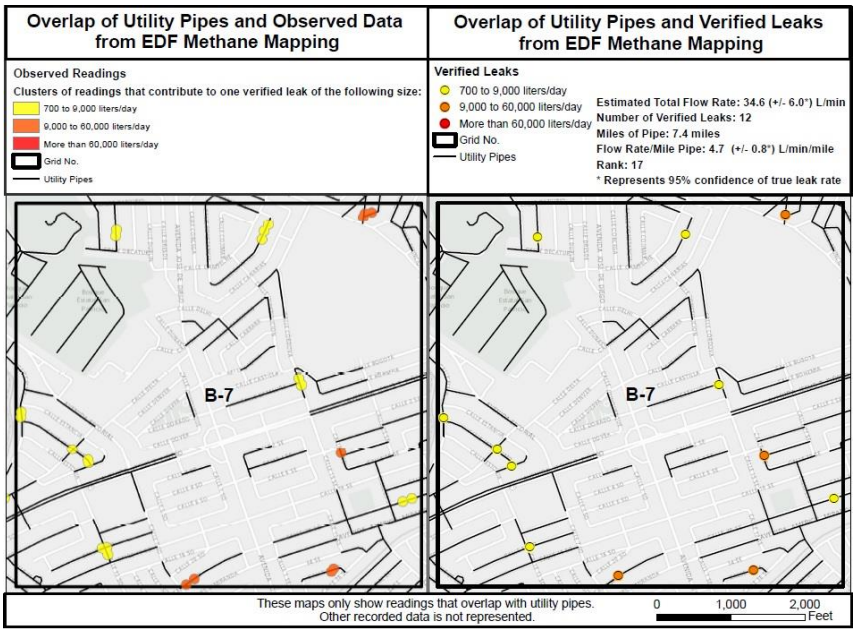

Figure 2 This simulated depiction of leaks in one grid cell of a utility's pipeline system demonstrates how overlapping observed readings are treated as individual "verified leaks," attributable to pipeline infrastructure. The result of such spatial attribution is a visual depiction of the relative size, frequency, and location of leaks in each grid cell.

6. Opportunities for Further Methodological Improvements

Leak quantification methodologies offers utilities an opportunity to use leak quantification to establish a baseline system-wide leak flow rate for their entire distribution system and measure progress in reducing emissions over time. Applied in this manner, quantification would be informative when considering major pipeline repair or replacement initiatives, allowing regulators and other stakeholders to assess the effectiveness of leak repair and pipe replacement programs in a transparent, measurable way.

Currently, utilities are building out and integrating advanced leak detection technology and spatial analysis into their routine pipeline safety and inspection programs. The federal rules establishing integrity management requirements for gas distribution pipeline systems ("Distribution Integrity Management Program for Natural Gas Distribution Sector") came into effect in 2011 (49 C.F.R. §192 [2009]). Under those rules, operators are required to develop and implement a distribution integrity management program. While the rules do not explicitly require utilities to quantify leaks, they state that: (1) pipeline operators must consider all reasonably available information to identify threats to pipeline integrity, and (2) the number and severity of leaks can be important information in evaluating the risk posed by a pipeline in a given location (49 C.F.R. §192.1007 [2009]). Under the rules, operators are required to consider the following categories of threats to each gas distribution pipeline: corrosion, natural forces, excavation damage, other outside force damage, material or welds, equipment failure,

incorrect operations, and other concerns that could threaten the integrity of its pipeline. Sources of data may include, but importantly, are not limited to: incident and leak history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, and excavation damage experience.

With technology available that makes leak quantification methods commercially available and viable, and PHMSA rules requiring operators to consider all relevant data in identifying threats to pipeline integrity, it is clear that the prevailing regulatory framework not only allows for leak flow rate to be considered in evaluating threats to pipeline integrity, but in fact, underscores the need to do so.

Some utilities, in addition to those described above, are already making use of leak quantification technology for this purpose. In California, Pacific Gas & Electric Co. (PG&E) is exploring how to integrate leak quantification technology into its leak management efforts (Pacific Gas and Electric Company, 2015b; Pacific Gas and Electric Company, 2012). This includes collecting leak data in a format that supports predictive analytics for assessing and mitigating risks to PG&E's infrastructure. CenterPoint Energy has also begun pilot testing advanced leak detection technology in Houston, Texas, and Minneapolis, Minnesota (Centers and Coppedge, 2015). The company has implemented a phased deployment strategy to evaluate and use advanced leak detection technology for leak surveys, and integrated the resulting data into leak prediction models that rely on spatial analytics. A collaborative, utility-led effort exploring leak quantification methods is also underway.[13]

A recent report by researchers at PricewaterhouseCoopers discusses the benefits of using spatial analytics to predict when and where pipeline leaks will occur (Wei et al., 2016). The authors describe how using quantitative failure history data, customer calls, and condition assessments can enable utilities to transparently manage their system, reduce human error, and cost-effectively improve decision-making (Wei et al., 2016). Traditional risk assessment has relied heavily on subject-matter experts who may use subjective data to make decisions about prioritizing risk mitigation actions. The report proposes that integrating spatial analytics with condition assessment data can allow operators to obtain a quantitative snapshot of asset risks in near real-time to inform investment planning and pipeline replacement project prioritization. The report further indicates that advanced leak detection technology can be used to provide data on leak density that can be integrated into a predictive model of leaks, further enabling capital prioritization. Such an approach can lead to efficiency and cost savings. For example, a case study presented in the report found that the client's quantitative spatial analytics model "delivered an estimated 3.9 times more leaks avoided, 3.6 times greater leaks/mile replaced, and 4.1 times more O&M (operations and maintenance) expense cost savings for the same capital investment" (Wei et al., 2016).

7. Conclusion

Quantifying and ranking leak flow rates for prioritization of leak repair and pipe replacement programs makes it possible to achieve larger reductions in gas lost for the same amount of time and resources, resulting in more cost-effective leak repair and pipeline replacement programs. As demonstrated by PSE&G's successful use of new practices to prioritize a large-scale pipe replacement program, leak

[13] i.e. NYSEARCH. 2014. "Technology Evaluation and Test Program For Quantifying Methane Emissions Related to Non-Hazardous Leaks." https://www.nysearch.org/tech_briefs/TechBrief_Methane-Emissions-Quantification.pdf

quantification technologies and methodologies can currently be deployed to prioritize leak repair and pipeline replacement programs. Using leak quantification allows for more robust leak prioritization, which helps to improve safety, minimize waste of natural gas, and reduce greenhouse gas emissions. Moving forward leak quantification will allow utilities to establish a baseline of system leaks that can provide an improved mechanism for comparing pre- and post-repair/pipe replacement outcomes to evaluate the success of such programs.

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Appendix A: Emission Reduction Analysis

EDF quantified leak flow rates in 30 grids that PSE&G had designated as needing pipeline replacement. PSE&G replaced pipes in the most hazardous grids first, then used leak flow rate as an additional layer for prioritizing pipes for replacement in grids with lower, but comparable hazard indexes. This appendix describes the estimated emissions impact of this prioritization scheme.

The goal of this analysis was to quantify the amount of avoided methane emissions resulting from EDF's methane mapping activities in PSE&G's system, particularly with respect to pipeline grids that were prioritized for replacement as a result of having leak flow rate data available.

To determine this impact, leak flow rate reduced per replacement effort was considered. This includes an analysis of the percent of leak flow rate avoided under each scenario (i.e. business as usual or prioritized based on leak flow rate) and a comparison to the percent of mileage replaced under each scenario. This would give a comparison of the relative leak flow rate reduced per mile of expenditures, rather than a direct estimate of the leak flow rate reduced over time. Calculating the leak flow rate reduced over time was not possible, because we did not have data demonstrating when each grid would have undergone replacement in a business-as-usual scenario.

A.1 Procedures

PSE&G indicated that any grid with a hazard index per mile (HI/mi) greater than 25 would hold the highest priority for replacement (Table 1; grids shaded in orange). Where HI/mi was comparable (between 25 and 10 HI/mi), leak flow rate data was used to help sub-prioritize the grids by leak flow rate normalized by the number of miles in each grid. This parameter was expressed as liters per minute per mile (L/min/mi). In the datasheet, grids that met the above criteria and were prioritized based on leak flow rate were shaded in green. Three grids were prioritized this way.

The first step in determining the amount of avoided methane emissions was to sort all of the grids in order of final ranking (Table 1). Next, the cumulative percent of leak flow rate (L/min) and the cumulative percent of mileage for each successive grid was calculated (see far right columns). Finally, the same calculations were made ordering the grids by "GSMP UPCI Grid Rank" to represent the business-as-usual case (Table 2).[14] These calculations allow a demonstration of the leak flow rate avoided for each successive replacement effort, and allow a comparison between the business-as-usual case and the final ranking that includes leak flow rate.

A.2 Calculating uncertainty

Researchers at Colorado State University calculated a measure of uncertainty for the flow rate (L/min) and flow rate per mile (L/min/mi) in each grid. The measure of uncertainty, or confidence interval, was based on two times the standard deviation, which was calculated as 60% of the flow rate divided by the square root of the number of verified leaks found in each grid. Within this confidence interval, the flow rate range is expected to be true 95% of the time. In calculating a confidence interval for a select number of grids, the measure of uncertainty was summed for the total estimated flow rate (L/min) in the selected grids.

[14] GSMP stands for "Gas System Modernization Program." UPCI stands for "Utilization Pressure Cast Iron."

A.3 Avoided leak flow rate by mileage replaced

Three grids (2B-42, 2L-43, and 2C-43) met PSE&G's criteria for prioritization based on leak flow rate, and had not already been prioritized based on the hazard index. Three other grids (2A-48, 2K-44, and 2A-45) had a flow rate of greater than 10 L/min/mi, but were already prioritized based on hazard index. The green shaded grids that were prioritized based on leak flow rate, rather than hazard index, add up to a flow rate (L/min) of 37% of the total flow rate. Table 1 shows the grids in order of final ranking and demonstrates the leak reductions that could be achieved through prioritization of each successive grid, as well as the corresponding percentage of pipeline miles that had to be replaced to reach each successive leak flow rate reduction.

The grids were replaced in order of final ranking, with the orange-shaded grids having been replaced first. The total emissions reduced are calculated as a cumulative percentage from the time that the first grid (2A-48) undergoes pipeline replacement, until the last-ranked green-shaded grid (2B-42) undergoes pipeline replacement. By the time pipeline replacement takes place in all three green-shaded grids with an HI/mi less than 25, the total flow rate reduced is 83% (Table 1 at grid 2B-42). This flow rate reduction was achieved through replacing less than 60% of the surveyed pipeline mileage (Table 1 at grid 2B-42).

In this prioritization, 11 grids out of 30 (Table 1, grids 1Y-48 to 2D-53) were ranked as a lower priority than the three non-hazardous, green-shaded grids. If the business-as-usual ranking based only on hazard is considered (Table 2), the three green-shaded grids would have been prioritized lower, and all but three grids out of 30 (Table 2, grids 2B-42 to 2D-53) would need to be replaced to reach the same level of avoided emissions (83%) that came as a result of prioritization based on leak flow rate. In the business-as-usual prioritization, by the time a flow rate reduction of at least 83% would have been achieved, 99% of the pipeline miles would have to have been replaced (Table 2 at grid 2C-43).

Grid	Miles of UPCI Pipe in Grid	Total Estimated Flow Rate (L/min)	Estimated Flow Rate per Mile (L/min/mi)	Hazard Index per Mile (HI/mi)	GSMP UPCI Grid Rank	Rank by Estimated Flow Rate per Mile	Final Ranking	Cumulative Percent of Miles	Cumulative Percent of Total Estimated Flow rate (L/Min)
2A-48	1.07	16.08	15.03	54.9381	1	19	1	1%	1%
1Z-47	7.49	52.46	7.00	25.9084	15	10	2	5%	4%
2L-57	4.21	9.15	2.18	45.3544	2	24	3	7%	5%
2K-57	4.23	2.33	0.55	27.8521	11	25	4	10%	5%
2L-58	1.77	1.93	1.09	27.7219	12	27	5	11%	5%
2K-45	5.49	51.03	9.30	37.2695	3	9	6	14%	8%
2K-44	3.43	119.20	34.75	36.7325	5	5	7	16%	15%
2B-46	2.54	10.19	4.01	36.1869	6	23	8	17%	15%
2A-45	2.25	329.34	146.37	28.0060	10	1	9	19%	34%
2K-55	12.89	24.85	1.93	32.5147	7	17	10	26%	36%
2L-55	10.64	20.65	1.94	20.8300	28	14	11	32%	37%
2J-51	9.34	36.13	3.87	29.1177	8	11	12	37%	39%
2H-50	5.75	34.58	6.01	24.7551	17	12	13	41%	41%
2D-58	2.87	9.94	3.46	28.1752	9	20	14	42%	42%
2C-43	6.91	426.80	61.77	19.6449	39	2	15	46%	66%
2L-43	7.41	189.20	25.53	23.6801	20	3	16	50%	77%
2L-51	8.05	68.93	8.56	24.1780	18	4	17	55%	81%
2H-45	4.28	11.95	2.79	24.1516	19	22	18	57%	82%
2B-42	1.09	15.81	14.50	20.6577	32	16	19	58%	83%
1Y-48	4.14	23.29	5.63	23.3831	22	18	20	60%	84%
1V-50	8.2	58.26	7.10	22.2527	23	6	21	65%	88%
1V-49	2.52	1.98	0.79	20.6865	29	26	22	67%	88%
2P-53	1	0.00	0.00	22.0075	24	28	23	67%	88%
2J-52	8.95	50.98	5.70	20.6443	33	8	24	72%	91%
2G-51	10.38	28.43	2.74	20.4184	34	15	25	78%	92%
1T-60	1.97	0.00	0.00	20.3291	35	29	26	79%	92%
2 E-43	4.18	22.97	5.50	20.1753	36	13	27	82%	94%
2N-44	14.21	94.22	6.63	19.8060	37	7	28	90%	99%
2J-53	12.49	14.88	1.19	19.0926	42	21	29	97%	100%
2D-53	4.88	0.00	0.00	19.0639	44	30	30	100%	100%

Table 1 Grids in order of final ranking. Grids with flow rates shaded in green were prioritized based on leak rate. Grids with hazard index shaded in orange were replaced based on hazard index. Final ranking incorporates both hazard and flow rate. An additional 22 grids scheduled for replacement where leak flow rates were not quantified are not included in this table.

Grid	Miles of UPCI Pipe in Grid	Total Estimated Flow Rate (L/min)	Estimated Flow Rate per Mile (L/min/mi)	Hazard Index per Mile (HI/mi)	GSMP UPCI Grid Rank	Rank by Estimated Flow Rate per Mile	Final Ranking	Cumulative Percent of Miles	Cumulative Percent of Total Estimated Flow Rate (L/min)
2A-48	1.07	16.08	15.03	54.9381	1	5	1	1%	1%
2L-57	4.21	9.15	2.18	45.3544	2	21	3	3%	1%
2K-45	5.49	51.03	9.30	37.2695	3	7	6	6%	4%
2K-44	3.43	119.2	34.75	36.7325	5	3	7	8%	11%
2B-46	2.54	10.19	4.01	36.1869	6	16	8	10%	12%
2K-55	12.89	24.85	1.93	32.5147	7	23	10	17%	13%
2J-51	9.34	36.13	3.87	29.1177	8	17	12	22%	15%
2D-58	2.87	9.94	3.46	28.1752	9	18	14	24%	16%
2A-45	2.25	329.34	146.37	28.0060	10	1	9	25%	35%
2K-57	4.23	2.33	0.55	27.8521	11	27	4	28%	35%
2L-58	1.77	1.93	1.09	27.7219	12	25	5	29%	35%
1Z-47	7.49	52.46	7.00	25.9084	15	10	2	33%	38%
2H-50	5.75	34.58	6.01	24.7551	17	12	13	36%	40%
2L-51	8.05	68.93	8.56	24.1780	18	8	17	41%	44%
2H-45	4.28	11.95	2.79	24.1516	19	19	18	43%	45%
2L-43	7.41	189.2	25.53	23.6801	20	4	16	47%	56%
1Y-48	4.14	23.29	5.63	23.3831	22	14	20	50%	57%
1V-50	8.2	58.26	7.10	22.2527	23	9	21	55%	61%
2P-53	1	0	0.00	22.0075	24	28	23	55%	61%
2L-55	10.64	20.65	1.94	20.8300	28	22	11	61%	62%
1V-49	2.52	1.98	0.79	20.6865	29	26	22	63%	62%
2B-42	1.09	15.81	14.50	20.6577	32	6	19	63%	63%
2J-52	8.95	50.98	5.7	20.6443	33	13	24	68%	66%
2G-51	10.38	28.43	2.74	20.4184	34	20	25	74%	68%
1T-60	1.97	0	0	20.3291	35	29	26	75%	68%
2 E-43	4.18	22.97	5.50	20.1753	36	15	27	78%	69%
2N-44	14.21	94.22	6.63	19.8060	37	11	28	86%	74%
2C-43	6.91	426.8	61.77	19.6449	39	2	15	90%	99%
2J-53	12.49	14.88	1.19	19.0926	42	24	29	97%	100%
2D-53	4.88	0	0	19.0639	44	30	30	100%	100%

Table 2 The business-as-usual ranking, with grids in order of hazard index per mile (GSMP UPCI Grid Rank).

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