The Non-Abatement of Methane Leaks

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Abstract

We provide a novel approach to estimate how much money natural gas utilities spend to abate product leaks. We show that firms exert less effort than what is theoretically optimal for a typical private firm; expenditure on abatement is below the cost of lost gas. This is consistent with the fact that many of these price-regulated natural monopolies are allowed to pass the cost of lost gas on to their customers. Importantly, natural gas, primarily composed of methane, is both explosive and a potent greenhouse gas. As such, abatement incentives are far lower than safety and climate costs warrant.

Key Words: natural gas, methane leaks, price regulation, utilities, pipelines, infrastructure
JEL: Q41, L95, D22, D42

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Methane (CH_4) emissions have been the focus of much recent public attention. This invisible gas is 34 times more potent a greenhouse gas than carbon dioxide, yet its release to the atmosphere has been largely unregulated. One source of methane emissions is leaks from the natural gas industry: methane is the primary component of natural gas. Leaks throughout the U.S. natural gas supply chain result in roughly $8 billion dollars of climate impacts annually.[1] The U.S. federal government is now developing standards to reduce methane leaks in the oil and gas sector. However, the economics literature on methane leaks is largely nonexistent. In this paper, we estimate the amount that natural gas distribution companies, delivering gas to end-use customers, spend to reduce leaks. This is a sector that will not be covered by the new methane regulations, and it has had limited reductions in methane to date. The academic literature has come primarily from engineers and natural scientists, and it has emphasized measurement issues (Miller et al., 2013; Phillips et al., 2013; Brandt et al., 2014; Howarth, 2014; Jackson et al., 2014*a*,*b*; Lamb et al., 2015; McKain et al., 2015).[2] In contrast, we examine the financial incentives of firms to abate leaks. We are the first in the economics literature to take advantage of data long-reported to the U.S. government on leaks from natural gas distribution companies. This is a contribution in its own right. Regulators and academics have generally dismissed these data because of measurement error, however we provide empirical strategies that overcome the data quality issues.

Leaks can occur from faulty connections, decaying infrastructure, or intentional venting at every stage of the supply chain: extraction, transmission, storage, and distribution. We focus on the distribution network; around 1,500 local distribution companies are responsible for delivering natural gas to end users in residences and businesses. Distribution is a natural

[1]This calculation uses the 322 billion cubic feet (Bcf) the Environmental Protection Agency estimated for 2012 (DOE 2015), the most recent year for which data are finalized. For the social cost, we use a global warming potential of 34 and the Interagency Working Group's social cost of carbon for 2015 emissions, $41 per ton. Using Marten et al. (2015)'s estimate of the social cost of methane (for 2020 emissions with a 3% discount rate) leads to the same estimate of $8 billion.

[2]Non-academic reports on methane leaks and aging pipelines include Aubuchon and Hibbard (2013); Costello (2012, 2013); Department of Energy (2015); Yardley Associates (2012).

monopoly because the necessary pipelines entail both large fixed costs and economies of density (Joskow, 2007). As such, most natural gas distribution firms are price-regulated investor-owned utilities. In this process, inefficiencies are introduced, largely stemming from the regulator's inability to perfectly observe firm effort (Posner, 1969; Laffont and Tirole, 1986; Joskow, 2007). We examine a previously unstudied distortion in the natural gas distribution sector, in which firms are allowed to pass the cost of lost gas on to customers. We are able to observe how much the investor-owned utilities spend each period, as well as how much gas is leaked. We then compare the value of the lost commodity to the estimated costs utilities are willing to undertake. The natural gas industry provides an excellent opportunity to test the general question of whether price-regulated firms cost-minimize, because the researcher is able to observe the commodity value of gas lost as well as effort undertaken to prevent those losses. We find that cost-effective opportunities to mitigate leaks exist, but utilities do not fully take advantage of them.

These results are consistent with a setting where price regulations weaken the incentive to cost-minimize, and we document institutional details to explain the mechanisms underlying our finding. A key mechanism appears to be the willingness of regulators to count leaked gas as simply a "cost of doing business," allowing utilities to be reimbursed for leaks in their retail rates.

Importantly, the distortion induced by price regulation in this setting is more costly than in many other settings, because the leaked commodity imposes outsized external costs. The full social cost of leaked natural gas is around an order of magnitude larger than the commodity value.[3] In contrast, the ratio of social to private cost is a little less than three for coal and less than two for gasoline (Parry et al., 2014). Thus in a second-best setting without a carbon tax, reducing distortions stemming from economic regulations could have substantial environmental benefits. Additionally, given the rapid recent growth in the natural

[3]This paper is focused on methane escaping to the atmosphere, before combustion by an end-user. The social cost of *combusted* natural gas is lower; the social cost upon combustion, including the emitted CO2 and local pollutant emissions, is a bit less than twice the private cost of the gas (Parry et al., 2014).

gas market (Hausman and Kellogg, 2015; Mason, Muehlenbachs and Olmstead, 2015; Covert, Greenstone and Knittel, 2016), this margin for climate change policy may be taking on greater importance. Moreover, if the gas accumulates (for instance, in a building), it can combust – resulting in property damage and loss of life. A 2011 explosion in Allentown, Pennsylvania, caused by a leaking cast iron pipeline, killed five people. A 2010 explosion in San Bruno, California killed eight people and destroyed 38 homes.[4] This accident was caused by a transmission line, but it led to greater public and regulatory scrutiny for both transmission and distribution lines.

Using a panel of US natural gas utilities, we empirically isolate the cost of abatement undertaken using an instrumental variables strategy. As we describe later, the academic literature on regulated utilities has largely ignored natural gas firms, so no previous estimates exist. Moreover, while engineering estimates give a range of costs for *potential* activities, they cannot tell us the cost of actions utilities have actually undertaken. As such, they do not allow for tests of cost minimization. Utilities can abate in a myriad of ways, including methods relying on operations and maintenance (O&M) procedures that leave pipeline infrastructure intact, and methods involving capital expenditures that replace aging pipelines. We show that the estimated cost of O&M-intensive abatement undertaken by utilities is below the commodity price of the lost gas. This is consistent with utilities not fully internalizing commodity costs because of cost-of-service price regulations. The estimated cost is also well below the social cost of leaks, after accounting for greenhouse gas and safety impacts. To estimate the safety benefits of leak abatement we collect data on property damages, injuries, and fatalities caused by incidents related to leaks and low-quality pipelines. We monetize these, using a standard Value of a Statistical Life assumption, to be able to include safety impacts in our cost/benefit calculations.

We also estimate the levelized cost of capital-intensive abatement in the form of pipeline upgrades. To do so, we estimate two parameters: (1) the cost per mile of pipeline re-

[4]Source: http://ww2.kqed.org/news/2015/09/08/five-years-after-deadly-san-bruno-explosion-are-we-safer

placement, and (2) a pipeline emissions factor: the amount of methane leaked per mile of low-quality pipe. Using these estimates, plus assumptions on the pipeline lifetime and the discount rate, we calculate the levelized cost. We provide a range of cost estimates, documenting reasons to suspect heterogeneity. The entire range of estimates is substantially higher than the O&M-intensive abatement cost. When compared to social costs, some pipeline upgrades appear to pass a cost/benefit test, while others do not. This heterogeneity is driven by differences in replacement costs, differences in emissions factors, and differences in explosion risk.

Finally, to better understand the abatement cost estimates, we look empirically and in greater depth at utility expenditures. Specifically, we exploit within-utility variation in a wide selection of financial, regulatory, and safety incentives. We find overall that expenditures are correlated with variables aimed at capturing various economic and safety regulations, rather than with non-regulatory financial incentives (such as commodity cost). This is consistent with industry reports, as well as with the abatement cost estimates, and it implies that the regulatory environment is an important determinant of firm maintenance choices.

Our paper makes several additional contributions to the literature. First, the existing research on natural gas distribution companies is quite small, and generally limited to two areas. One strand of this literature has focused on retail pricing decisions (Davis and Muehlegger, 2010; Borenstein and Davis, 2012). Another strand, related to operational decisions, has estimated various efficiency measures (see e.g., Farsi, Filippini and Kuenzle, 2007, Tanaka and Managi, 2013, Tovar, Ramos-Real and Fagundes de Almeida, 2015). We contribute to this literature by examining in depth the impact of the regulatory structure on a large sample of US utilities. To do so, we construct a dataset on a comprehensive set of variables, including utility expenditures, pipeline infrastructure, regulatory proceedings, and safety incidents.

Additionally, a long literature has analyzed natural monopoly regulation, but it generally has focused on the electric power sector (e.g., Fabrizio, Rose and Wolfram, 2007; Fowlie, 2010, Davis and Wolfram, 2012; Abito, 2014; Hausman, 2014; Cicala, 2015; Lim and Yurukoglu, 2015). The US natural gas distribution market was worth almost 80 billion dollars in 2013,[5] but the financial incentives of these utilities have not been widely studied. The electricity sector has provided a clean natural experiment, because price regulations were removed from many firms in the late 1990s and early 2000s, and researchers have been able to take advantage of this variation. In contrast, we propose an approach that can be applied even in a setting where only regulated utilities are observed. Rather than comparing the behavior of price-regulated and competitive firms, we compare the willingness of firms to prevent leaks with the commodity value of the leaks themselves. Comparing firm behavior to a theoretical optimum, rather than relying on natural experiments from policy changes, may allow for the study of price regulations in a wider array of industries.

With worldwide methane emissions currently valued at over $300 billion per year in climate change costs, policy-makers are increasingly looking for mitigation opportunities.[6] Our results can inform discussions about how to achieve the least-cost abatement in the distribution sector. In this setting, the presence of distortions from price regulations implies that there is "low-hanging fruit" for climate change abatement. That is, some methane leak abatement would be economically worthwhile for its commodity costs alone – this has parallels in the search for negative abatement costs in the energy efficiency literature. The energy paradox literature has suggested that there may be substantial negative cost abatement opportunities, but this claim is controversial (Allcott and Greenstone, 2012). Our setting contributes by pointing out an area ignored by previous studies, and by focusing on an important mechanism: the failure of price regulations to ensure privately optimal emissions controls. Finally, our paper relates to questions of maintaining and replacing aging infrastructure, which will have implications in domains such as water, transportation infrastructure, and the electricity grid.

[5]Distribution sales, valued at the price distribution companies paid for the gas, from the Energy Information Administration (EIA).

[6]The IPCC estimated 49 GtCO2-eq of anthropogenic greenhouse gas emissions in 2010, of which 16% were methane (https://www.ipcc.ch/pdf/assessment-report/ar5/syr/SYR_AR5_FINAL_full.pdf).

Section 1 provides background on natural gas utilities and regulations. Section 2 describes the data sources, with a detailed description of leaked gas data. In Section 3, we describe our empirical strategy and provide our results, estimating both the cost of leak detection and repair and the cost of pipeline replacement. In Section 4, to understand the mechanisms underlying our main results, we empirically examine associations between utility expenditures and various financial and regulatory variables. Section 5 concludes.

1 Background

The earliest natural gas companies were established in the 1820s and 1830s in cities such as Philadelphia, Boston, and New York, with the earliest use for street lighting. Connections to homes and businesses accelerated after World War II. Every year, over 8,000 new miles of distribution pipeline are added, and the current network is composed of over 1 million miles. In 2013, the distribution market as a whole was worth almost 80 billion dollars[7] and served 72 million customers.[8]

1.1 Natural Gas Leaks and Infrastructure

The Environmental Protection Agency (EPA) estimated in 2013 that 1.4 percent of natural gas leaked from the supply chain (Jackson et al., 2014*b*). However, considerable uncertainty persists, and academic scientists and engineers have questioned the EPA estimates (Brandt et al., 2014). Some of the uncertainty comes from observed differences in bottom-up type approaches, with emissions factors estimated for specific components of the supply chain, compared to top-down approaches that use atmospheric studies (Jackson et al., 2014*b*). It is widely believed that leak rates are highly varied across space and time, with a small number of sites accounting for an outsized portion of leak volumes. While this heterogeneity

[7]Distribution volumes totaled almost 16 billion thousand cubic feet (Mcf), and the average price paid by utilities in 2013 was $4.99/Mcf.

[8]This breaks down to 67 million residential, 5 million commercial, and almost 200 thousand industrial and electric power customers.

is problematic for scientific consensus and life-cycle analysis, it may point to heterogeneity in marginal abatement costs that, if well understood, could be leveraged to make regulations cost-effective (Brandt et al., 2014).

Of the 322 billion cubic feet (Bcf) estimated by the EPA to have leaked in 2012, 32 percent was from the production stage, 14 percent from processing, 33 percent from transmission and storage, and 20 percent from distribution (DOE 2015). In this paper, we argue that the distribution component is worthy of investigation. First, by far the largest reductions in natural gas leaks in recent years have come from the other stages, suggesting that the distribution sector merits closer attention. In 2013, the EPA estimated that its voluntary reductions program, the Natural Gas STAR Program, led to a reduction in methane emissions of 51 Bcf, with 81 percent coming from production, 17 percent coming from transmission, 2 percent from gathering and processing, and less than 1 percent from distribution.[9] Other years saw similar breakdowns. Moreover, the distribution sector carries outsized safety risks because of its location in population centers. An average of 11 fatalities, 50 injuries, and $25 million in property damages occur annually as a result of incidents in the natural gas distribution system. While many of these occur because of excavation accidents, over which a utility has little control, 20 percent of incidents occur because of corrosion failures, equipment failures, etc.[10]

Several components of the distribution system lead to natural gas emissions. First, leaks can occur at metering and pressure stations; these include the "citygate" where the utility receives the gas from the transmission line as well as downstream pressure reduction stations. As components age, or if they have not been properly fitted together, gas escapes. Second, underground pipelines leak, including mains (shared lines) and services (lines connecting customers to mains). As pipes corrode, they can develop cracks – and similar to loose fitting components in pressure stations, loose fitting pipes also lead to escaped gas.

[9]Source: US EPA Natural Gas STAR program website, http://www3.epa.gov/gasstar/accomplishments/index.html, accessed Feburary 16, 2016.

[10]Source: PHMSA data, described later in the paper.

Emissions also occur when utilities intentionally vent equipment. For instance, to undertake maintenance projects, sections of pipeline are purged of gas, frequently by releasing the gas to the atmosphere. Finally, emissions can occur when forces largely beyond the control of the utility lead to damaged equipment. Third-party excavation damages (e.g., home-owners hitting a line when digging) are common, as are vehicle collisions with infrastructure.

Pipeline leaks have perhaps attracted the most public attention. Around 15 percent of the nation's distribution pipelines are at least 50 years old; another 8 percent are of unknown age. Moreover, much of the oldest infrastructure is composed of cast iron or bare steel, materials that are especially prone to leak. The risks associated with these pipes have been highlighted by incidents like the 2011 Allentown, PA explosion. Researchers have found particularly high leak rates in cities like Boston and Washington, D.C., which have especially high concentrations of cast iron and bare steel pipe (Phillips et al., 2013; Jackson et al., 2014*a*; McKain et al., 2015). Utilities have been slowly, but systematically, replacing older pipelines. Boston Gas Company, for instance, reduced its miles of pre-1940s pipes by over fifteen percent from 2004 to 2013.[11] The utility in Allentown, PA has reduced its miles of pre-1940s pipes by 25 percent since 2004, but 9 percent of its service territory was still this quality of pipe as of 2013, the most recent year for which we have comprehensive data. Nationwide, pre-1940s pipes have been reduced by almost twenty percent since 2004. In addition, utilities have undertaken efforts to better identify the age and quality of their pipeline infrastructure. Pipes of unknown vintage have been reduced by more than 25 percent since 2004, a combination of pipeline replacement as well as better data collection on age.

Throughout this paper, we refer to the benefits, in dollars per thousand cubic feet ($/Mcf), of leak abatement. The first benefit is saved commodity costs, which as described later, are equal to the citygate price of natural gas. In 2015, this averaged $4.25/Mcf. Over our sample (1995-2013), this averaged $6.80/Mcf for all utilities and $7.44/Mcf for the investor-owned utilities on which we focus. The second benefit of leak abatement is averted

[11] Source: PHMSA data, described later in the paper.

climate change impacts. At a social cost of carbon of \$41/ton and a global warming potential of 34, this is equal to around \$27/Mcf. The final benefit is averted explosions, which we estimate in \$/Mcf terms later in the paper.

1.2 Environmental and Safety Regulations

Two federal government agencies regulate natural gas leaks from the distribution sector. The EPA has a voluntary reductions program, the Natural Gas STAR Program, which provides technical advice regarding abatement options throughout the supply chain. Materials for this program tend to cite benefits related to greenhouse gas impacts as well as operational efficiency.[12] In addition, the Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) regulates natural gas pipeline safety. PHMSA issues regulations and conducts inspections and enforcement operations. Most recently, PHMSA issued a new rule on "Gas Distribution Integrity Management Programs," tightening standards on distribution pipelines. The rule was issued in December 2009, and operators were required to comply by August 2011. Each utility is required to develop its own risk-based program, which PHMSA then approves. PHMSA coordinates with state-level agencies, which in some cases layer on additional regulations.

Thus, state-level regulations have generally been motivated by, and directed at, safety impacts rather than climate change impacts per se. Historically, federal regulations have not explicitly targeted the climate change component of methane leaks, beyond the EPA's voluntary program. The executive branch is, however, in the process of proposing a suite of actions targeting methane leaks.

[12] See e.g. the "2012 EPA Natural Gas STAR Program Accomplishments" document. Accessed February 16, 2016 from http://www3.epa.gov/gasstar/documents/ngstar_accomplishments_2012.pdf.

1.3 Economic Regulations

Natural gas distribution is a natural monopoly. It has high fixed costs related to surface stations and pipelines, and costs are lowered by having a single network within a city. As a result, the industry has long faced economic regulation. Economic regulation takes two forms in this context: some utilities are investor-owned utilities facing price regulations, and other utilities are owned and operated by municipal governments.[13]

Investor-owned utilities tend to serve larger customer bases, and accordingly make up 90 percent of total gas delivered in the US. Municipal utilities, while smaller in total volume delivered, are greater in number – in 2013, over 70 percent of utilities were government agencies. In this paper, we focus largely on investor-owned utilities, for which more data are available, but we comment in the conclusion on municipally run distributors.

Investor-owned utilities are regulated by state-level public utility commissions (PUCs) via a cost-plus form of price regulation. The utility is reimbursed for its operating and capital expenses, earning a fair rate-of-return on capital for its investors. Both this reimbursement process and retail-rate setting occur through a quasi-judicial process involving the commission and the utility. Disincentives for pipeline upgrades are possible for a couple of reasons. First, it has been argued that necessary pipeline replacements are slowed down by the rate case process (Yardley Associates, 2012). In recent years, alternative regulatory proceedings to accelerate pipeline upgrades have been introduced, which we explore in more depth below.

Additionally, in almost all jurisdictions, utilities are able to include the cost of leaked gas directly in their retail rates, and thus are not incentivized to reduce leaks. To incentivize leak abatement, some state utility commissions limit the amount of leaked gas that can be passed through to ratepayers. However, a 2013 survey asked state utilities commissions "What incentive does your commission provide utilities to manage LAUF [lost and unaccounted for] gas?," and 19 of 41 responded "None" or something similar (Costello, 2013). "Lost and unaccounted for gas" (LAUF) is the only widely available measure of leaks and is simply

[13] A small portion – around 2 percent – of distribution companies are cooperatives or have other structures.

the difference between gas purchased and gas sold. Utilities have argued that both LAUF volumes and commodity prices are volatile and outside of their control, and therefore they should be able recover the cost in their rates (Costello, 2013).

Below, we empirically examine the possibility that cost-of-service price regulations introduce inefficiencies, through rate case timing and through cost pass-through of leaked gas. We also examine the validity of using lost and unaccounted for gas as a proxy for leaks.

2 Data

We collect data from several government agencies on natural gas utility operations, constructing a panel of around 1,500 utilities covering the years 1995 to 2013. The bulk of our data are from SNL, a company providing proprietary energy data. The SNL data combine information from a large number of sources, including the Department of Energy's Energy Information Administration (EIA), the Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA), and state-level public utility commissions.

First, the SNL data include information from the EIA-176 database, which identifies all utilities by type (investor owned, municipally owned, other) and location.[14] This census contains annual data for all utilities on volumes of gas purchased and delivered. For deliveries, volumes are broken down by sector (residential, commercial, industrial, electric power, other). At the sectoral level, we also observe the number of customers and revenue by sector. Finally, this dataset includes estimates of losses from leaks and accidents, which we describe in greater detail below.

Second, the SNL data include detailed annual data from PHMSA on infrastructure at all utilities. Specifically, the dataset tracks miles of distribution pipes and number of customer connection lines, broken down by type. Materials are separated out (e.g. cast iron, plastic,

[14] We drop utilities that appear in this dataset but report zero delivered volume to end users.

copper), as are the decades of installation.[15] PHMSA data also track the number of known leaks eliminated/repaired, by type (e.g. corrosion, excavation damage, etc). Separately, from PHMSA we obtain a dataset that tracks accidents, reporting the date, number of injuries and fatalities, and dollar value of property damages.

We also collect financial data from SNL for a subset of investor-owned utilities. The original source of this financial information is state-level filings of utilities with public utility commissions. This information on investor-owned utilities includes annual operations and maintenance (O&M) expenditures, new capital expenditures, number of employees, etc.[16] Separately, SNL also provides information on all rate cases that investor-owned utilities face. These data are assembled by SNL from state-level regulatory documents; the dataset includes dates of rate cases, dollar amounts requested, and dollar amounts granted. We additionally assembled from several sources a list of alternative rate case proceeding regulations, which we discuss below.

We use the annual state-level citygate price, in dollars per thousand cubic feet ($/Mcf), from the EIA. The citygate is the location where a utility receives gas from the transmission system, and as such the citygate price represents the utility's commodity cost. We also observe (from EIA) the annual price at Henry Hub, the central location for futures contracts. Finally, we convert all prices and revenues to 2015 dollars using the CPI (all items less energy) from the Bureau of Labor Statistics.

Table 1 provides summary statistics for the primary variables of interest. Statistics are provided for the full sample of utilities, as well as for the sample of investor-owned utilities for which we have financial data. Comprehensive financial information on municipally-owned utilities is not available. While investor-owned utilities make up only 25 percent of company counts, they are on average much larger than municipal utilities. As such, investor-owned

[15] Materials data are available for our entire time period, but age data begin only in 2004. Moreover, around 10% of miles are reported as "unknown decade." As a result, we focus on materials rather than age for most of our analysis.

[16] The capital data are incomplete for 1995-1997, so in some of the specifications we limit the sample to 1998-2013.

Table 1: Summary Statistics

	Full			With Financial Data		
	Mean	Std. Dev.	N	Mean	Std. Dev.	N
Volume leaked, Bcf	0.17	2.05	22,801	1.05	4.54	2,959
Volume leaked, %	1.71	3.70	22,801	1.05	2.63	2,959
Volume purchased, Bcf	14.88	77.39	25,341	81.56	154.44	3,053
Pipeline mains, miles	842.77	3,271.49	23,751	5,299.67	7,419.01	2,813
Unprotected bare steel	43.40	289.98	23,752	323.18	757.48	2,813
Unprotected coated steel	14.80	168.97	23,752	106.76	465.37	2,813
Cathodically protected bare steel	11.34	175.74	23,752	49.92	184.24	2,813
Cathodically protected coated steel	347.83	1,618.34	23,752	2,189.26	3,489.17	2,813
Plastic	391.43	1,515.43	23,752	2,393.24	3,504.53	2,813
Cast iron	30.98	212.47	23,752	219.35	566.60	2,813
Other	2.96	119.95	23,751	17.94	343.64	2,813
Low-quality mains, %	4.24	11.88	23,640	10.66	14.27	2,813
Average pipeline age, years	25.72	13.59	11,686	27.08	10.31	1,730
City-gate price, $/Mcf	6.80	2.46	35,663	7.44	3.43	3,254
Henry Hub price, $/Mcf	5.81	2.41	32,334	5.97	2.43	3,291
O&M expenses, $000				24,376.03	37,302.60	3,496
Capital expenses, $000				37,116.69	66,047.49	2,901

Notes: The full sample is a census of 1,580 natural gas distribution utilities. The financial reporters sample is composed of 240 large investor-owned utilities, representing 75% of total end user sales. Most variables are available for the period 1995-2013; but capital expenses data begin in 1998 and pipeline age data begin in 2004. The upper and lower five percent of leak rates have been trimmed, as described in the text. Low-quality mains refers to pipeline mains made of ductile iron, unprotected bare steel, and cast iron. Henry Hub prices are quoted in dollars per mmBtu; we assume a heat content of 1.025 mmBtu per Mcf. Prices and expenses are listed in 2015 dollars.

utilities make up 90 percent of all volumes delivered in the US. We are only able to observe financial information on a subset of these, which are again larger than the typical investor-owned utility. Overall, the investor-owned utilities with financial data make up 75 percent of all end user sales from the distribution network.

We next provide a detailed understanding of leak data. For years, the EIA has collected data on natural gas leaked from both the transmission and distribution network. Industry reports have criticized the use of these data, claiming that any information on leaks is overwhelmed by accounting errors. We investigate the validity of this claim, finding that while the data are quite noisy, the leaks variable moves in ways expected with infrastructure quality.

Specifically, we analyze the difference between purchases and sales, reported by all utilities in the EIA-176 form. Purchases include supply coming from own production, storage withdrawals, and receipts from other companies. Sales include sales to end-use customers, fuel used in the firm's operations, storage injections, and sales to other utilities. The difference between these two quantities reflects, in principle, gas that escaped the system.[17] In the industry, this is known as lost and unaccounted for gas or LAUF.[18]

However, our leaks variable, defined as the difference between purchases and sales, is imperfect. In particular, it is very noisy. Figure 1 shows the tremendous noise in this variable. (For presentation purposes, the histogram trims the upper and lower 1 percent tails of the observation.) Around 30% of the observations fall below zero, which is not physically possible for leaks. Moreover, a significant portion of observations (8 percent) lie above ten percent, which is a highly improbable leak rate. To reduce the amount of variation driven by extreme mismeasurement, throughout the paper we trim outliers (the upper and lower 5% of leak rates); but our results are generally robust to trimming only the upper and lower 1%.

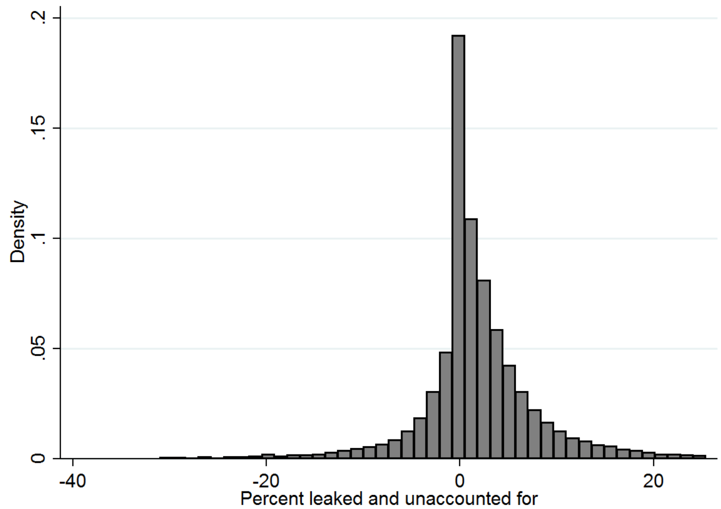
There are several reasons that the LAUF variable may not correspond exactly to leaks to the atmosphere, some of which also explain the noise. For volume measurements to be consistent, a gas must be at a standard temperature and pressure. Respondents to the EIA-176 survey are instructed to correct all volumes to a standard temperature of 60 degrees and a standard pressure of 14.73 psia, but there may be errors in this calculation. Second, there are frequently timing differences between the periods over which purchases are tracked and the periods over which sales are tracked (depending on contractual arrangements such as billing cycles).[19] Similarly, the amount of gas stored in the pipeline itself can vary over time.

[17] The EIA-176 form has also, since 2002, asked utilities to report the volume in thousand cubic feet (Mcf) of "Losses from leaks, damage, accidents, migration and/or blow down within the report state." If a company had no known losses or leaks, it reported estimates based on engineering studies (Personal communication, EIA staff) – the dataset does not report which observations are from known leaks and which from engineering estimates. Until 2010, many companies failed to report this variable. Because this is sometimes based on engineering estimates, and because of the incomplete time coverage, we do not use this variable. Nonetheless, this volume is captured in our measure of escaped gas, since it shows up in the purchases variable but not in the sales variable. For a small number of observations, 2% of the total, LAUF is exactly equal to the negative of known leaks. For these observations, we use simply the leak variable, as a precise offsetting of the two is implausible. Nevertheless, our results are robust to not correcting for the leaks that exactly offset LAUF.

[18] This is known by other acronyms as well, including "LUAF," "LAUG," and "UFG."

[19] To examine the potential magnitude of this empirically, we compared the distribution of one-year LAUF rates to 10-year LAUF rates. The 10-year LAUF rate distribution is narrower, but not substantially so.

Figure 1: Percent Lost and Unaccounted for Gas



Note: This histogram gives the density of leak volumes as a percentage of total volume purchased. The upper and lower 1 percent tails of the distribution have been trimmed. A unit of observation is a utility-year combination, with around 1,500 utilities across 19 years (1995 to 2013). The data source is EIA via SNL, as described in the text.

There are also errors from meter inaccuracies and accounting mistakes.[20] Additionally, theft rather than leaks could account for lost gas, although this is presumably small. Finally, gas that leaks from underground pipes is partially oxidized by surrounding soil and thus does not escape to the atmosphere as methane. Oxidation rates vary, with one widely-cited study estimating an average rate of 18 percent (Kirchgessner et al., 1997).

However, we posit that if our measure responds in systematic ways to indicators of infrastructure quality, then it is not purely noise. Figure 2 shows the association between the percent of gas that is leaked and two measures of pipeline quality: materials and age. The left-hand panel plots the percent of gas that is leaked against the percent of pipeline miles that are constructed with low-quality material. Low-quality materials are defined here, and throughout the paper, as cast iron, ductile iron, and unprotected bare steel. A unit of observation is a utility in a year, with around 1,500 utilities covering the years 2004-2013. Observations are sized according to the total volume of gas sold. The black line shows a

[20]While some utilities have aimed to improve meter accuracy rates over time, we do not see a narrowing over time of the distribution of LAUF in our data.

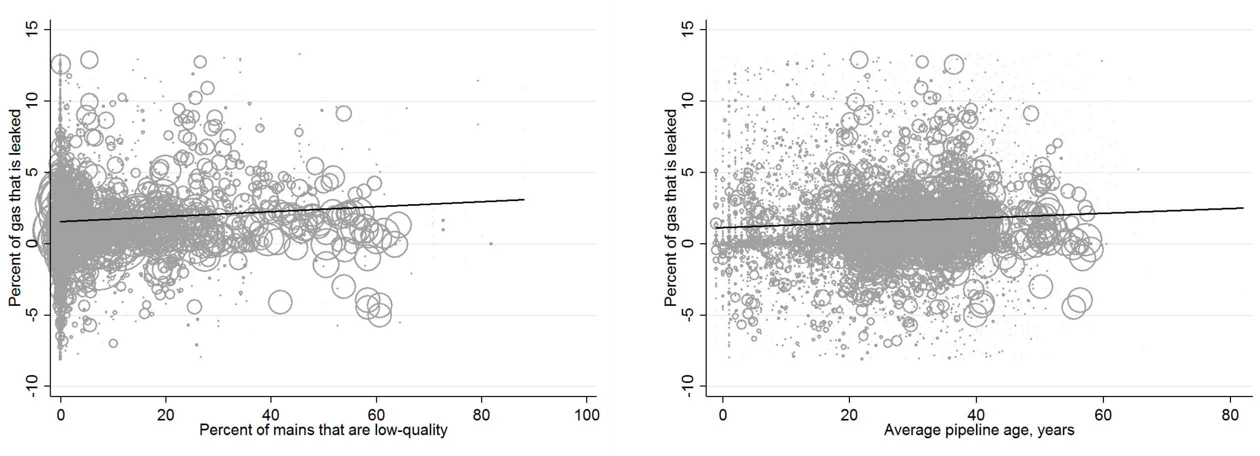
regression line fit through the observations. While there is a great deal of noise in the leaks variable, there does appear to be a positive relationship between leak rates and low-quality pipes. It is also worth noting that there are a number of large utilities with a sizeable fraction of low-quality pipes. Boston Gas Company, Brooklyn Union Gas Company, Consolidated Edison of New York, and Philadelphia Gas Works all had networks in 2013 with at least 40% of miles composed of low-quality materials. Combined, they served over 3 million residential customers in 2013. The right-hand panel shows that a similar relationship holds for pipeline age, rather than material. These relationships are formalized in the Appendix, with regressions that include both pipeline quality and pipeline age, as well as a number of controls (Table A2).

Finally, we also note that there appears to be significantly less measurement error in the percentage of gas leaked for the sub-sample of utilities on which we have financial data. In the Appendix, we show that the distribution of leaked gas is narrower for these utilities. We also calculate, for each utility, the standard deviation in the percentage of gas leaked across years. The average of these values across the financial reporters is substantially lower (by around 45 percent) than the average for the other utilities. This is consistent with the investor-owned utilities being larger, and perhaps more sophisticated, firms than, for example, municipal distributors. We are reassured that measurement error will be less of an issue for the firms on which we focus our analysis. Most importantly, our empirical estimates in the following sections use methods that are robust to measurement error.

3 Cost Estimates

We next estimate the cost of abatement activities undertaken by utilities. The EPA's Natural Gas STAR program has identified a number of abatement opportunities for distribution companies, with varying cost, targeting different components of the distribution system. We classify them into two broad categories: (1) leak detection and repair; and (2) pipeline re-

Figure 2: Lost Gas is Correlated with System Materials



Note: Low-quality materials are defined as cast iron, ductile iron, and unprotected bare steel. A unit of observation is a utility in a year, with around 1,500 utilities covering the years 2004-2013. Observations are sized according to the total volume of gas purchased. The black line shows a regression line fit through the observations. The data source is EIA and PHMSA via SNL, as described in the text.

placement. As described in the Background section, leaks can occur at surface facilities as components age or when they are poorly fitted together. One broad category of abatement involves identifying these leaks (at metering and regulator stations, for instance) and repairing them. Also falling in this category are activities to reduce so-called "blowdowns," the intentional venting of natural gas during maintenance projects. What we characterize as leak detection and repair can be broadly thought of as maintenance-related activities, with little capital investment.

3.1 Cost of O&M-Driven Repairs

The EPA's Natural Gas STAR program has released informational sheets on different leak detection and repair activities, including engineering cost estimates. We summarize a selection of these in the Appendix. Overall, they span a wide range of costs – from so negligible the EPA does not report a cost, up to almost $40 per Mcf, with many falling in the $0-5/Mcf range. We are interested in analyzing the cost of the activities actually undertaken by utilities in the past two decades. In particular, we aim to estimate the cost of abatement observed in our sample, to inform our understanding of the utilities' incentives.

For instance, we documented in the previous section that many utilities are fully reimbursed for the cost of their leaked gas, via cost-of-service price regulations. If all utilities were fully reimbursed, and they failed to internalize any safety or greenhouse gas costs, we would expect to see only abatement that could be completed at zero marginal cost. As a second example, if utilities were not reimbursed at all, but still failed to internalize any safety or greenhouse gas costs, we would expect to observe abatement equal to commodity costs (citygate prices). Binding safety or environmental regulations would incentivize utilities to abate at greater cost.

Since engineering estimates of *potential* abatement opportunities cannot inform our understanding of what utilities have been willing to do *historically*, we empirically estimate abatement costs. We regress expenditure amounts on volumes leaked, where the equation of interest is:

$$E_{it} = \beta_0 + \beta_1 L_{it} + X_{it}\Theta + \varepsilon_{it}. \tag{1}$$

Here E_{it} is operations and maintenance expenditures in 2013 dollars and L_{it} is the volume of leaked gas in Mcf.[21] The controls X_{it} include Census region-by-year effects, utility fixed effects, as well as a number of utility-specific, time-varying variables. We control for total volume purchased, total miles of mains, and counts of service lines to absorb variation from changes in utility operations stemming from, for instance, territory expansion. We control for miles of mains and count of service lines constructed of low-quality material, since utilities that have undertaken leak detection and repair are also likely to have undertaken pipeline replacement. We control for a count of known leaks that have not yet been repaired; this helps remove some of the noise in L_{it}. Finally, we control for repaired leaks that should be unrelated to the utility's own incentives to abate: in particular, if a third-party (such as a

[21]This specification imposes linearity on the total cost function, so that marginal cost is constant and equal to average cost. If marginal costs are actually rising, then our results would be biased. To examine this possibility, we estimate the equation including a quadratic term for L_{it} to allow for the possibility of rising marginal cost. The sign on the quadratic term is as expected, but the magnitude of the coefficient is very small and not statistically different from zero. Therefore, we conclude that our simplification is adequate, and that we can treat β_1 as the marginal cost parameter of interest.

residential customer) damages a pipeline during excavation, the utility must immediately repair it for safety concerns. This is not an expenditure we wish to capture, however, since the initial accident was out of the utility's control. In contrast, the cost estimates we are trying to capture relate to ongoing leak detection and repair at the purview of the utility itself. In the Appendix, we show that the results are robust to alternative sets of controls. Standard errors are clustered at the utility level.

The volume of leaked gas presents endogeneity concerns. Of most concern, as documented above, is that it contains a great deal of measurement error, which (if classical) will bias β_1 towards zero. Accordingly, we use an instrumental variables approach to identify the cost parameter β_1. Intuitively, instruments should be variables that incentivize leak detection and repair, impacting expenditures only through these abatement activities. We present results for two sets of instruments. First, we use known, pending leaks that were not repaired in the previous year.[22] These should incentivize repair activities, raising expenditures and reducing leak volumes. In any given year, a utility is not able to immediately repair all leaks, and some are deferred for the following year. As such, known leaks from the previous year are expected to directly lead to leak abatement in the current year.

One concern with this instrument is that it does not capture leak *detection*, only leak *repair*. It may be that a significant portion of the abatement cost comes from finding the leaks, before they can be repaired. As such, we consider an additional set of instruments, designed to capture both activities. We first consider instruments designed to capture the financial incentive to control lost gas: the commodity value of the gas, measured as the citygate price. However, as we describe in Section 1.3, many utilities are completely reimbursed for lost gas. One exception is that public utility commissions in some states report that utilities can only recover leaked gas if it is below a set percentage, most typically five percent. As such, we create a dummy variable for whether a utility's leaks in the previous two years were at least five percent, conditional on that utility being located in a state that

[22] I.e., lagged known pending repairs.

reports such an incentive.[23] We additionally interact that dummy variable with the citygate price of natural gas: it stands to reason that greater scrutiny might apply for these utilities when commodity values are high.

We next examine a set of instruments that relate not to financial incentives, but rather to safety regulations. The first safety-related instrument is the interaction of miles of low-quality pipe, held constant at the values observed in the first year of our sample, with a dummy for the years following the implementation of more stringent PHMSA safety regulations. The idea is that the PHMSA rules incentivized all utilities to upgrade their pipes, but these regulations were more binding for utilities with particularly bad networks. The utility fixed effects control for the level effect of having a historically bad network, so the IV is capturing only the differential effect following the implementation of PHMSA regulations. We also include a quadratic of this term, to allow the regulatory impact to be non-linear in the number of low-quality miles. The third safety-related instrument is a dummy for the California utilities following the San Bruno accident – public scrutiny for leaks was more intense in California following that fatal accident. In an additional specification, we also include a dummy that is specific to Pacific Gas & Electric (PG&E) following the San Bruno accident. PG&E was responsible for San Bruno and presumably faced greater scrutiny than did other California utilities.

The instruments give first-stage results with reasonable power and with expected signs. Full results for the first stage are provided in the Appendix (Table A3). The first-stage F-statistic, robust to clustering, is shown along with the 2SLS results, in Table 2. This table also shows the main coefficient of interest, which is on volume of natural gas leaked – this coefficient is the cost of abatement utilities have undertaken, in $/Mcf. (In the interest of space, we do not show in this table the coefficients on controls, but they are provided in the Appendix, Table A4.) The coefficient on volume leaked is expected to be less than zero in all five columns: it gives the increase in expenditures associated with a reduction in volume

[23] States are identified using the survey results in Costello (2013).

Table 2: Abatement Costs: Operations and Maintenance Expenditures

	OLS	Financial-Incentive Instruments		Safety-Incentive Instruments	
	(1)	(2)	(3)	(4)	(5)
	O&M	O&M	O&M	O&M	O&M
Volume leaked, Mcf	-0.23**	-0.88	0.29	-4.56***	-4.60***
	(0.11)	(1.54)	(1.47)	(1.25)	(0.85)
Controls	Yes	Yes	Yes	Yes	Yes
Region-year effects	Yes	Yes	Yes	Yes	Yes
Utility effects	Yes	Yes	Yes	Yes	Yes
Observations	2,598	2,372	2,372	2,058	2,230
Kleibergen-Paap F-stat.	.	11.33	12.17	7.16	67.56

Notes: Dependent variable is the utility's expenditures on O&M. Coefficients represent the amount spent on O&M, in $ per Mcf, to reduce natural gas leaks. The first column shows OLS results and the remaining four columns show results instrumenting for volume of leaked gas using the instruments in Table A3. The instrument in column (2) is the number of known leaks still pending repair at the end of the previous year. In column (3) additional instruments are included: the price of natural gas at the citygate, whether the utility faces a binding constraint on how much of the leaked gas can be recovered, and an interaction between the two. Instruments in columns (4) and (5) are driven by safety regulations. In column (4) the instruments are the number of known leaks still pending repair at the end of the previous year; an interaction between the 1995 miles of low quality mains (cast iron, ductile iron, and unprotected bare steel) and an indicator for the period after PHMSA increased regulation stringency; this interaction squared; and an indicator for utilities that were in California after the explosion in San Bruno. In column (5) the instruments are an interaction between the 1995 count of miles of low quality mains and an indicator for the period after PHMSA increased regulation stringency; this interaction squared; and an indicator for utilities that were in California after the explosion in San Bruno; and an indicator for the utility responsible for the explosion, after the explosion. Controls are the count of repaired leaks caused by outside forces, third party sources, or excavation; the number of known leaks pending at the end of the current year; total miles of pipeline mains; total service line counts; total miles and service counts made of unprotected bare steel and cast iron; and total volume purchased. Coefficients on controls are found in Appendix Table A4. Standard errors are clustered by utility. *** Statistically significant at the 1% level; ** 5% level; * 10% level.

leaked, i.e., the cost of abatement.

The first column shows the results when we do not instrument for the volume of leaked gas. In the OLS specification, the estimates of abatement expenditure is small: 23 cents/Mcf. Given the endogeneity concerns discussed above, the remaining columns are more informative. The following two columns focus on the instruments related to financial incentives, while the right-most columns focus on instruments related to safety incentives. When we instrument, in Column (2), with known leaks still pending repairs from the previous year, the first-stage F-statistic is reasonably strong: F=11. Here, we estimate an abatement cost that is small and not statistically different from zero. That is, the instrument is leading to leak repairs (as shown in the first stage results), but utilities are spending very little to accomplish these repairs. Because this instrument does not capture leak *detection* activities, we consider it a lower bound on abatement costs undertaken to both detect and repair leaks.

As such, Column (3) is designed to capture additional financial incentives to both detect and repair leaks. In particular, we include three instruments relating to the commodity value of lost gas (described in detail above). One might expect these to be powerful instruments: if utilities were fully internalizing the commodity value of lost gas, we would expect to estimate a strong first stage and an abatement cost equal to the sample average of the commodity price. However, the instruments in Column (3) do not provide much additional power. Moreover, the estimated cost of abatement remains, as in Column (2), small and not statistically different from zero.

Overall, across Columns (2) and (3), it appears that utilities do indeed repair leaks (as demonstrated by the signs and statistical significance of the first-stage coefficients), but that they spend very little to obtain the repairs. That is, the estimated cost of abatement is small. It is substantially below (and is statistically different from, at the 1 percent level) the commodity price in our estimation sample, which averages \$7.44/Mcf. This is consistent with price regulations (specifically, pass-through of leaked gas costs) weakening the incentives to abate leaks. In contrast, a firm fully responsible for the cost of leaks would be willing to abate up to a marginal cost equal to the benefit of abatement, i.e. the commodity price.

In Columns (4) and (5), we focus on instruments related to safety regulations. Here, the local average treatment effect (LATE) is quite different from that in Columns (2) and (3). The estimated cost of abatement in the right-most columns is local to the impact of safety regulations. Column (4) uses as instruments the impact of more stringent PHMSA regulations as well as a dummy for California utilities following San Bruno. Column (5) adds a dummy specific to PG&E following San Bruno. The first-stage F-statistic is particularly strong when we include the PG&E, post-San Bruno dummy. For the safety-related instruments, we estimate a larger cost of abatement, around \$4.60/Mcf.

It is intuitive that the safety-related instruments lead to a larger estimated cost: the result with these instruments is local to greater regulatory scrutiny of leaking gas. One would expect utilities to abate *beyond* the value that would be privately optimal for achieving commodity cost savings, if safety regulations were binding. That is, we would expect the abatement cost estimated in this 2SLS framework to be *larger* than the average treatment effect for the sample as a whole. It is thus even more striking that the abatement cost is only \$4.60/Mcf. For both columns, this is statistically different from an abatement cost of \$7.44/Mcf: at the five percent (Column 4) and one percent (Column 5) level. There is an additional reason the point estimate may be a bit higher than the true value: if the benefits of abatement persist beyond one year, then our estimates appear more expensive than abatement really is. It is difficult to verify this empirically, because estimation with lags requires multiple endogenous variables and multiple instruments, and we have low power. However, results using two potential years of abatement benefits suggest that indeed abatement persists beyond one year.

To summarize, we use an instrumental variables approach to estimate the cost of O&M-intensive leak abatement. Our preferred specifications give point estimates of around \$0/Mcf and \$4.60/Mcf, depending on the instruments used. In the Appendix, we show that these results are robust to alternative controls; while some specifications give larger estimates, our qualitative conclusions are unchanged. In the Appendix we also estimate equation (1) using capital expenditures as the dependent variable (Table A6). While there are statistically significant capital expenditures associated with leak detection and repair, they are small in levelized terms. Overall, our estimates are consistent with the range of cost estimates for leak detection and repair that are published by the EPA's Natural Gas STAR program (details in the Appendix). At the same time, they are below the cost of gas itself that utilities save when they repair leaks. Moreover, the higher estimate is a LATE driven by safety regulations, which would be expected to incentivize utilities to abate above and beyond the commodity value of leaked gas. Overall, these results are consistent with a setting where utilities are reimbursed for lost gas in the rates they charge customers, a choice made by public utility commissions. Moreover, despite increased safety regulations in recent years, the utilities are abating at a cost well below the social benefit of leak abatement. This social benefit is at least \$30/Mcf (incorporating the commodity value of the gas, the greenhouse gas benefits of avoiding methane leaks, and safety benefits to the public). This suggests that the quantity of leak abatement undertaken by utilities is currently lower than what a social planner would choose, although how much more abatement would be socially optimal cannot be calculated without knowing how steeply the marginal cost curve slopes upwards.[24]

3.2 Capital Cost of Pipeline Replacement

As mentioned previously, an alternative to leak detection and repair, of either surface stations or pipelines, is full replacement of pipeline infrastructure. This is a capital-intensive project requiring digging up aging pipelines and replacing them with new plastic or protected steel pipes. In this section, we estimate the cost of abatement from pipeline main replacement, then compare it to the benefit of replacement as well as the previously estimated cost of leak detection and repair.

The structural equation of interest is similar to that used for leak detection and repair:

$$E_{it} = \beta_0 + \beta_1 P_{it} + X_{it}\Theta + \varepsilon_{it}. \tag{2}$$

Our dependent variable of interest E_{it} will again be expenditures, but now we focus on capital expenditures. The independent variable of interest P_{it} is now total miles of low-quality materials, where we aggregate bare steel, cast iron, and ductile iron miles, the materials most widely targeted in recent years for replacement.

Miles of low-quality materials again poses endogeneity concerns, but they are slightly different from the leak-volume endogeneity concerns. First, measurement error is also possible for miles of low-quality pipes – much public attention has been paid, for instance, to out-of-date records at PG&E. To the extent that this shows up in the *level* of low-quality materials, it should not be a barrier, as we will use *changes* in low-quality materials as our

[24] While we can test for upward sloping marginal cost in our sample, of more relevance for calculating deadweight loss is knowing how quickly marginal cost increases outside our sample, i.e. for actions utilities have historically not taken.

identifying variation.

However, two additional sources of measurement error, this time non-classical, impact our choice of an estimation strategy. First, it is possible that the expenditures do not show up in exactly the same year of the data as the pipeline replacements, if pipeline replacement programs are spread out over several years. This would bias β_1 towards zero. More importantly, anecdotal reports suggest a form of non-classical measurement error of E_{it}, driven by the regulatory process. Suppose utilities face a budget constraint, determined by how much they deem is politically acceptable to request from the public utility commission in a given rate case.[25] Then, in order to spend money on pipeline replacement, they would save money elsewhere by deferring other capital expenditures. Since we observe only total expenditures, our left-hand side variable would be the net of these two effects, biasing our estimate towards zero. Unfortunately, comprehensive information on individual components of expenditures (for instance, pipeline upgrades as opposed to citygate station repairs) is not available.[26]

To deal with the first set of endogeneity concerns (e.g. classical measurement error), we again use an instrument related to safety regulations. These will not, however, solve the second set of endogeneity concerns, which stem from the way costs appear in the data over time. To address this concern, we use long differences, rather than year-to-year within-utility variation. In particular, we use the across-utility variation from the start of our sample to the end in total miles replaced and in total capital spent. The regression we estimate is thus:

$$\Delta E_i = \beta_0 + \beta_1 \widehat{\Delta P_i} + X_i \Theta + \varepsilon_i. \tag{3}$$

[25] For instance, Costello (2012) describes "no rate shock" as one of the ratemaking principles a commission might consider.

[26] One might worry about the same sort of soft budget constraint for operations and maintenance expenditures, impacting our estimates in Section 3.1. However, this may be less likely because distribution O&M is only a portion of total O&M expenditures, which also includes categories such as administrative expenses (executive compensation; employee pensions) and retailing expenses (e.g., meter reading), making distribution O&M less salient. In contrast, a significant portion of total capital expenditures are for the distribution network. In any event, because we observe individual categories of O&M (although not capital), we are able to examine this possibility empirically. In the Appendix, we show that cost estimates for subcategories of distribution O&M are generally smaller than our main preferred estimate, indicating that bias from an overall budget constraint is unlikely.

Here ΔE_i is new capital accumulated by the plant, calculated as the sum of new capital expenditures over the period 1998 to 2013.[27] ΔP_i is the reduction in low-quality pipeline miles from 1998 to 2013, instrumented with historic pipeline quality. Because the independent variable is the change in low-quality miles, time-invariant characteristics of utilities have been washed out. We additionally control (X_i) for several time-varying characteristics: the change in the total miles of any quality pipe in the system, the change in the total volume purchased with a flexible cubic functional form, and the change in the total customer count. These controls are designed to absorb the variation in capital expenditures arising from service territory expansions. Finally, we include region effects to allow for differential trends across regions.

The instrument we use is miles of low-quality pipes in the first year of our sample. As in the leak detection and repair regression, the intuition is that (with increasing regulatory scrutiny in recent years) utilities with poorer pipeline networks have had to undertake more extensive repairs. First stage results are given in the Appendix (Table A8); the coefficient on the instrument has the expected sign and is statistically significant at the one percent level. In the Appendix, we also show that the 2SLS results are similar with an alternative instrument (Table A10).

Table 3 gives OLS and 2SLS estimates.[28] After instrumenting for pipe replacement, the point estimate is 1,489 (in $000), implying that the replacement of one bad pipeline mile costs almost $1.5 million dollars. The OLS estimate is smaller, with one mile costing $1.1 million to replace. Both of these are in line with estimates from public utility commission reports, which show a range (details in the Appendix) of $170,000 to $3 million. While this wide range of reported estimates is striking, it plausible that there is substantial heterogeneity in the cost of pipeline replacement. Replacing pipe in a dense urban area, perhaps with cobblestone streets,[29] is likely more expensive than replacing pipe in a more rural area. Moreover, large

[27]As we mention in Section 2, the capital data are incomplete prior to 1998.

[28]Coefficients on controls are displayed in Appendix Table A9.

[29]See, e.g., a notice to customers regarding pipeline replacement in Pittsburgh, at http://apps.pittsburghpa.gov/district5/Regent_Square_Civic_Association.pdf.

Table 3: Cost of Pipeline Replacement

	Total Capital Expenditures, 1998-2013 ($000)	
	(1)	(2)
	OLS	IV
Low-quality main replacement, miles	1,112.17***	1,488.54***
	(208.36)	(277.42)
Controls	Yes	Yes
Region effects	Yes	Yes
Observations	119	114
Kleibergen-Paap F-stat.	.	80.37

Notes: Dependent variable is the sum of capital expenditures made from 1998 to 2013. In column (2) the reduction in low quality mains from 1998 to 2013 is instrumented for using the miles of low quality mains in 1995. First stage results are found in Table A8. Controls are the change in miles of pipeline mains, change in number of customers, and a cubic polynomial of the change in volume of gas purchased. Coefficients on controls are found in Appendix Table A9. Robust standard errors in parentheses. *** Statistically significant at the 1% level; ** 5% level; * 10% level.

cost savings might be achieved if repairs can take place at the same time that other street work is being done. Unfortunately, we have insufficient power to empirically estimate this heterogeneity.

To interpret the costs per mile in comparison to the benefits of leak abatement, we must next estimate the volume of leaks abated for each mile of pipeline replaced. To do so, we estimate the following equation:

$$L_{it} = \beta_0 + \beta_1 P_{i,t-1} + X_{it}\Theta + \varepsilon_{it} \tag{4}$$

where L_{it} is again the volume of gas leaked, in Mcf; $P_{i,t-1}$ is again the miles of low-quality pipes, and X_{it} is a vector of controls. Here we use lags because contemporaneous P poses a simultaneity problem. We want to capture the fact that leaks are higher when there are more miles of low-quality, rather than high-quality, pipes. The endogeneity concern is that, as described previously, gas is intentionally vented when repairs occur. That is, at the same time that low-quality pipes are replaced with high-quality pipes, gas is vented, increasing L. This will bias β_1 towards zero. The instruments we used in previous specifications will not help, since they incentivize repairs and therefore increase venting.

Lags should, however, address this concern: if a mile of low-quality pipe P is replaced in time t, volume leaked L should decrease in time $t+1$. As such, identification rests on leak abatement from pipeline replacement persisting. We find this plausible – while new pipes may decay somewhat, there should still be a benefit to having a one-year old pipe rather than a sixty-year old pipe. The controls X_{it} include a cubic function of purchases, the lagged number of total miles, excavation damages, region-by-year effects, and utility fixed effects. The cubic function of purchases aids with both precision (by absorbing a determinant of leaks) and with identification (since it could be correlated with service territory changes). Lagged total pipeline miles again control for service territory changes, so that the coefficient of interest is for the differential effect of a low-quality pipe relative to a high-quality pipe. Excavation damages aid with precision. Region-by-year effects control for differential trends in leak rates across regions coming from, for instance, differential weather trends.

The resulting estimates (in the Appendix, Table A11) are extremely noisy: 900 Mcf are abated per mile of low-quality pipe replacement, with a standard error of 794 Mcf. This large standard error is consistent with two plausible explanations. First, as documented above, the left-hand side variable contains a great deal of measurement error, which leads to low power. Second, it is plausible that actual emissions factors are heterogeneous, because it is likely that some very old pipes have decayed more rapidly than others (subject to, for instance, heterogeneous weather conditions).

We should also note an additional concern with this estimate: we expect it to be higher than the emissions factors of *remaining* pipes, since the estimate is driven by variation in historical changes in pipes, and utilities presumably targeted the leakiest pipes first. Accordingly, the estimate 900 Mcf/mile is as an upper bound on the average emissions factor. We must also correct the emissions factor for the 18 percent oxidation rate described in Section 2, and thus use 737 Mcf/mile as an upper bound to the emissions factor.[30] In

[30] From the *utility's* perspective, this soil oxidation is irrelevant; the gas is still lost to the system. From the social planner's perspective, however, the soil oxidation lowers the amount of gas that contributes to climate change. From a utility's perspective, then, the true levelized cost would be somewhat lower than the calculations shown in Table 4. This would not change the conclusions we present below.

contrast, the EPA uses an estimate of 229 Mcf per mile of cast iron relative to plastic pipe.[31] Some of the academic literature (Brandt et al., 2014; Howarth, 2014; McKain et al., 2015) has criticized EPA emissions factors throughout the supply chain as too conservative, so we use this estimate as a lower bound.[32] At the beginning of the paper we discussed the relationship between leak *rates* and average age and material quality, with formalized regression results presented in Appendix Table A2. We note that transforming these coefficients at mean sample values for the financial reporters gives an emissions factor between the EPA's rate and our noisily estimated upper bound.

With estimates of the cost of replacing a mile of low-quality pipe, and an emissions factor for a mile of low-quality pipe, we can calculate the cost per Mcf abated associated with pipeline replacement. Because this is a capital-intensive activity with benefits that are expected to persist over time, we calculate the implied levelized cost of abatement. A levelized cost gives the constant, in real terms, price of abatement over the lifetime of a project. Similar calculations are used in, for instance, calculations of long-run electricity costs, e.g. Borenstein (2012). The equation we use is:

$$LC = \frac{\sum_t \left(\frac{E_t}{(1+r)^t}\right)}{\sum_t \left(\frac{Mcf_t}{(1+r)^t}\right)} \tag{5}$$

where LC is the levelized cost; E_t when $t = 0$ is the capital cost at the time of the pipeline replacement; E_t when $t > 0$ is the future stream of payments associated with the program (described below); Mcf_t is the emissions abated in period t, and r is the discount rate. Our preferred calculation uses the estimated \$1.5 million pipeline replacement capital cost; an alternative calculation uses \$650,000, a low-end estimate reported in public sources (see Table A13). We further assume that the emissions abated in each year, Mcf_t, are constant, and we calculate the levelized cost under the upper and lower bounds: 229 Mcf/mile and

[31] Source: Annex 3, Table A-138 of Environmental Protection Agency (2015*a*).

[32] The EPA is considering revising these emissions factors downwards to reflect pipeline upgrades (Environmental Protection Agency, 2015*b*), but we note that these lower estimates would apply for future years, rather than our sample.

Table 4: Levelized Cost of Abatement via Pipeline Replacement

	(1)	(2)	(3)	(4)	(5)	(6)
Capital cost, $	1,488,540	650,000	1,488,540	1,488,540	1,488,540	1,488,540
Abatement rate, Mcf/mile replaced	737	737	229	737	737	737
Discount rate	0.03	0.03	0.03	0.07	0.03	0.03
Lifetime	40	40	40	40	20	40
Offset O&M, $ per year	-3,049	-3,049	-3,049	-3,049	-3,049	0
Levelized cost, $/Mcf	81	33	261	138	128	85

Notes: This table gives the implied levelized cost of abatement associated with one mile of pipeline replacement, under various parameter assumptions. Column (1) is the preferred specification, as described in the text. Columns (2) - (6) vary the capital cost, abatement rate, discount rate, pipeline lifetime, and offset O&M, respectively.

737 Mcf/mile. For a discount rate, we follow the EPA, showing 3 percent and 7 percent. We must also make an assumption about the total lifetime of the project benefits. For our preferred calculation, we use a lifetime of 40 years; an alternative calculation uses 20 years. Finally, in addition to the one-time capital cost in period $t = 0$, we must make an assumption about the impact of the replacement program on the stream of operating costs. Following Aubuchon and Hibbard (2013), we assume that O&M expenditures decrease after the replacement program. We use the simple average of the offset O&M that they report for six utilities: $3,049 per mile per year. To examine the impact of this assumption, we also show the levelized cost if there are no O&M savings.

Table 4 shows the resulting levelized cost calculations. With our preferred set of parameters, we calculate a levelized cost of natural gas leak abatement of $81/Mcf from pipeline replacement programs. This cost varies from $33 to $261 under alternative assumptions, in Columns (2) - (6).

This estimated levelized cost is clearly well above the cost of leak detection and repair activities undertaken by utilities – it is an order of magnitude larger. As such, we can conclude that pipeline replacement has not historically been a cost-effective method (on average) of capturing lost commodity, nor of averting greenhouse gas consequences. However, it does not necessarily follow that utilities are engaging in too much pipeline replacement, from a social planner's perspective. First, as Column (2) demonstrates, the levelized cost of pipeline replacement is close to the benefit of replacement in areas where capital costs are lower than average. And crucially, leak detection repair programs and pipeline replacement programs may not be substitutes for one another in terms of averting explosions. That is, the safety benefits of leak repair are likely different from the safety benefits of pipeline replacement. Leaks from pipelines may pose a greater safety risk if gas is more likely to accumulate, rather than escape to the atmosphere. Moreover, incidents caused by low-quality pipes may be more costly to society than incidents caused by, for instance, citygate station leaks, if the former lead to explosions in densely populated urban areas.

Using PHMSA data on fatalities, injuries, and property damages, we estimate the safety benefits of reducing leaks and of replacing low-quality miles. We use a panel 2SLS approach, with the same instruments used in our abatement cost estimation. We assume a Value of a Statistical Life of $9.1 million, as is common in the literature. Estimation results are provided in the Appendix, Table A14. Because the results are quite noisy, we are reluctant to rely too heavily on the point estimates. In addition, it is possible that an infrequent "black swan" event could change our calculations.[33] However, a few broad conclusions emerge.

The estimated safety benefits for both leaks reductions and low-quality mains replacements are small compared to the greenhouse gas benefits. The safety benefits associated with leaks reductions are estimated to be at most $0.56/Mcf. The safety benefits associated with pipeline upgrades are in the range of $100-500 per mile per year, or $0.12/Mcf to $1.86/Mcf (depending on the emissions factor used). This translates into a net present value that is substantially less than the replacement costs estimated in Table 3. As such, our qualitative conclusion about the cost-effectiveness of the *average* pipeline replacement does not change. However, we maintain that heterogeneity is likely to matter, although we have insufficient power to explore it empirically. That is, pipeline upgrades may well pass a cost-benefit test when they are in very densely populated areas (where the safety benefits are largest), where leak rates are highest, and where replacement costs are lowest. Additionally,

[33] For instance, a 1996 explosion in Puerto Rico killed 33 people and wounded 80 more. It does not appear in our data, which do not cover Puerto Rico. Before natural gas was odorized, one of the deadliest accidents occurred at a Texas high school in 1937 – around 300 people were killed.

using the emissions factors presented above, it appears that the safety benefits of a pipeline upgrades may be larger, in $/Mcf terms, than the safety benefits of other leaks reductions. This is intuitive, since other leaks reductions may be achievable at surface stations far from urban centers, whereas pipeline upgrades may occur in heavily populated areas.

Overall, we conclude that pipeline replacement programs have not historically been the most cost-effective way of addressing greenhouse gas externalities, but that they may well be socially optimal in some places.

4 Incentives to Abate

Finally, to explain the low abatement effort for leak detection and repair found in Section 3, we next look empirically at utility expenditures in greater depth. Bearing in mind the incentives for abatement described qualitatively in the Background section, here we look for corroborating empirical evidence using our panel data. We regress expenditures on a broad set of variables describing the economic and regulatory environment facing utilities, controlling for utility fixed effects and region-by-year effects.[34] We control for several variables: leaks caused by third-party accidents; leaks that went unrepaired, total pipeline miles, and total volume of gas purchased. These controls are designed to absorb variation that could impact expenditures and could also be correlated with the explanatory variables (for instance, expansion of service territory). We do not claim that this regression can identify causal mechanisms; rather, we hope to understand within-utility and within-year associations between expenditures and various financial and regulatory variables. This provides some evidence to corroborate the intuition presented in the Background section and the finding of sub-optimal expenditures on leak detection and repair.

The first explanatory variable we consider is the citygate price of natural gas. If utilities were competitive firms, and with an upward sloping marginal cost of abatement, we would

[34]We estimate this equation in levels, in keeping with the preceding analyses. A regression in logs (in the Appendix) gives qualitatively similar results.

expect that they would spend more money on maintenance when citygate prices were high, to avoid losing valuable gas. In contrast, if public utility commissions allow utilities to recoup their lost gas costs in regulated rates, utilities should not respond to citygate prices. As Table 5 shows, utilities spend *less* in the short-run on maintenance (although not significantly different from zero) and capital when citygate prices are high. One possible explanation is the reimbursement of the cost of leaked gas. An additional possible explanation is the desire of commissions to avoid "bill shock" or "rate shock" (Costello, 2012) – to keep total bills from varying too much across years, capital projects could be disproportionately carried out when commodity costs are low. Overall, the lack of a positive coefficient on the commodity cost of natural gas is consistent with regulatory distortions, such as commodity cost pass-through.

The second variable we include on the right-hand side is the number of leaks pending repairs at the end of the previous year. Every year utilities must report this count to PHMSA. In theory, this should lead to higher expenditures, with utilities undertaking these pending repairs in the current year. As Table 5 shows, the point estimate is small and not different from zero. Recall that this variable was an instrument for leak abatement volume in Section 3.1. There we found, as one would expect, that more leaks pending repair in the previous year imply more leak abatement occurring in the current year. That we find known leaks do not move O&M expenditures reiterates our previous finding that the abatement that is happening is inexpensive.

Next we consider the timing of rate cases. We include both the portion of the current year that is during a rate case, and the portion of the year that is a test year. A rate case, which can last for several years, is the period after a utility (or commission) calls for a change in rates and before the new rates take effect. A test year is typically a 12-month period, during which expenditures are carefully tracked to determine what cost recovery is necessary. Table 5 shows that these variables are associated with higher spending, both in terms of O&M expenditures and capital expenditures. There are two possible explanations, which cannot be separately identified in this regression framework, because rate case timing

Table 5: Reduced-Form Estimates of What Explains Utility Expenditures

	Expenditures ($ millions)		
	(1)	(2)	(3)
	Total	O&M	Capital
Economic and Regulatory Variables:			
City-gate price, $/Mcf	-3.34**	-0.50	-2.29*
	(1.46)	(0.40)	(1.27)
Lagged known pending leak repairs, thousands	0.91	-1.11	2.00
	(2.39)	(0.89)	(1.62)
Fraction of year in a rate case	12.68***	3.16**	8.45**
	(4.41)	(1.26)	(3.32)
Fraction of year in a rate-case test year	8.23***	1.62***	6.61***
	(2.99)	(0.62)	(2.41)
I(Utility has pipeline rider)	-4.76	-2.88*	-2.70
	(5.42)	(1.53)	(4.45)
Low-quality mains, thousands of miles*I(post-PHMSA)	30.72**	6.03	23.87**
	(13.50)	(3.71)	(10.52)
Low-quality mains, thousands of miles^2*I(post-PHMSA)	-3.75	-1.29	-2.25
	(3.08)	(1.01)	(2.20)
I(California)×I(post-San Bruno accident)	110.85*	44.14**	68.49*
	(60.23)	(21.24)	(38.35)
Controls:			
Repaired accidental leaks, thousands	6.29	-0.84	7.01**
	(4.56)	(1.52)	(3.38)
Known pending leak repairs, thousands	0.46	1.65	-1.21
	(2.30)	(1.15)	(1.37)
Mains, thousands of miles	4.05	1.07*	2.33
	(2.50)	(0.59)	(2.04)
Volume purchased, Bcf	-0.08	0.01	-0.07
	(0.17)	(0.04)	(0.12)
Region-year effects	Yes	Yes	Yes
Utility effects	Yes	Yes	Yes
Observations	1,799	2,116	1,863
R^2	0.34	0.30	0.30

Notes: Dependent variable in column (1) is the sum total of capital and O&M expenditures in millions of dollars, in column (2) O&M expenditures, and in column (3) capital expenditures. O&M data begin in 1995; capital data begin in 1998. "Low-quality mains*I(post-PHMSA)" is an interaction between the low quality mains, in thousands of miles, and an indicator for the period after PHMSA regulations increased in stringency. "I(California)×I(post-San Bruno accident)" is an indicator for utilities that are in California after the explosion in San Bruno. "Repaired accidental leaks" is the count of leaks repaired during the year which occurred because of outside forces, third party sources, or excavation. "Known pending leak repairs" is the number of known leaks still pending at the end of the year, scheduled for repair. Standard errors are clustered by utility. *** Statistically significant at the 1% level; ** 5% level; * 10% level.

is endogenous. First, utilities could call for a rate case when they expect their expenses to be exogenously high. Second, utilities could pad expenses during rate cases to increase rates. For the first explanation, no first-order inefficiency is expected; utilities could still be spending the socially optimal amount. There could, however, be inefficiencies arising from intertemporal allocations of expenditures. As described in the Background section, the gas industry has claimed that the rate case process hampers timely pipeline upgrades (Yardley Associates, 2012).

As mentioned in the Background section, alternative regulatory procedures have arisen to handle pipeline replacement capital costs. These "targeted infrastructure" programs or "capital trackers" are designed to allow utilities to recover capital costs associated with the replacement of antiquated pipes without having to wait for a rate case. Rather than waiting for a rate case, a utility is allowed to add a "rider" to retail bills – a line item with a separate charge for recovery of infrastructure capital costs (Yardley Associates, 2012; Aubuchon and Hibbard, 2013). We obtained information on whether a utility has a rider and the date that it was implemented.[35] We do not detect increased expenditures associated with the implementation of such a mechanism, but we note that the implementation is likely endogenous. For instance, it is possible that it has been implemented in places that were already replacing low-quality pipelines.

Finally, we consider three variables designed to capture regulatory stringency. We include the interaction of the post-PHMSA regulation dummy with a count of the number of low-quality miles in the first year of our sample, 1995. We also include a quadratic of this interaction. Again, this interaction captures the differential effect for the utilities with worse networks, in the years when following the new PHMSA regulations. As expected, we find higher spending, particularly for capital. This is consistent with utilities responding to safety regulations by increasing expenditures for abatement projects.

[35] The majority of the company names and implementation dates came from the lists compiled in Lowry, Makos and Waschbusch (2013) and American Gas Association (2013), but these were also supplemented with information from an online search.

Next, we examine the impact of the San Bruno accident on expenditures. We interact a dummy for utilities in California with a dummy for the years following San Bruno. In the years following the accident (which occured September 9, 2010), the California Public Utilities Commission issued more stringent orders for several California utilities.[36,37] Again, the estimated coefficients are consistent with safety regulations having an impact on utility expenditures decisions.

The final four rows of Table 5 are controls. The first control is the count of leaks caused by third-party accidents, such as excavation damages by home-owners. As expected, this raises expenditures. Next we control for leaks pending repairs at the end of the year. This is not associated with expenditures in the current year, as expected. We also account for total pipeline miles and total volume of gas purchased, to absorb any variation coming from utilities expanding their service territory.

In summary, we see that variables associated with economic regulations (such as the rate case variables) and variables associated with safety regulations (such as the post-PHMSA interaction variables) are associated with both O&M expenditures and with capital expenditures. In contrast, the coefficient on the citygate price has an unexpected sign, and we are unable to detect an effect of pending leak repairs. Overall, this suggests that incentives for abatement expenditures are not properly aligned in terms of avoiding lost commodity value. In contrast, they are driven by economic regulations and safety regulations.

5 Conclusion

This paper provides the first test of natural gas utility behavior to avoid commodity leaks. Despite the commodity, climate change, and safety costs associated with leaked natural

[36]See, e.g., the fact sheet "California's Pipeline Safety Rulemaking Timeline," published January 2013 by Southern California Gas Company, and accessed March 15 2016 at https://www.socalgas.com/documents/news-room/fact-sheets/PipelineSafetyTimeline.pdf.

[37]We note that the San Bruno accident occurred around the same time as the more stringent PHMSA regulations, which had been planned well before the accident. As such, it is possible this variable is also capturing something differential about California implementation of the new PHMSA regulations.

gas, losses continue to occur throughout the supply chain. Focusing on the distribution network, we find that utilities are under-incentivized to abate leaks because of the form of price regulations they face. Public utility commissions have historically considered lost gas a "cost of doing business," and they have generally allowed this to be passed on to retail customers. Using an instrumental variables strategy, we estimate a lower bound of realized abatement costs for leak detection and repair of close to \$0 per Mcf.

Increasingly stringent safety regulations have, however, led to increased utility expenditures and decreased leak rates. These include both federal regulations, imposed and enforced by PHMSA, and increased scrutiny in California following the San Bruno accident. Using an instrumental variables strategy that yields a treatment effect local to the impact of these safety regulations, we estimate realized abatement costs of around \$4.60 per Mcf. While this indicates that leak detection activities are indeed being undertaken by utilities because of safety concerns, the realized abatement cost is far below the total benefits to society. These include saved commodity value (currently around \$4.25/Mcf) plus avoided climate change damages (around \$27/Mcf) as well as the safety benefits that motivated the regulations.

In contrast, we estimate that pipeline replacement programs, which have received much public attention, have levelized costs well above the leak detection and repair activities described above. This implies that more cost-effective abatement could be undertaken with leak detection and repair. It does not, however, imply that some pipeline replacement programs would not pass a cost/benefit test. Indeed, for some parameter combinations, we calculate levelized costs that are close to the societal benefits described above.

Overall, we conclude that price regulations have introduced a distortion in the natural gas distribution market, by under-incentivizing utilities to avoid the leakage of their primary input. This distortion has had outsized social impacts because of the substantial wedge between commodity costs and social costs, including environmental and safety impacts. Resolving the price-regulation distortion could have substantial social benefits. We recognize, however, that resolving this issue is not completely straightforward. The only measure of lost gas that is available on a comprehensive basis is "unaccounted for gas," calculated as the difference between gas purchased and gas sold. This measure has known issues. While the measure is useful for our analysis once we use an empirical strategy that is robust to substantial measurement error, regulatory penalties associated with a very noisy measure may be politically challenging to implement. That is, any overhaul of price regulations would perhaps only be feasible if accompanied by better measurement of leak rates. Regulators have indeed been considering technological solutions to this problem.[38]

We conclude by noting, however, that resolving the price regulations problem will not alone achieve the theoretically optimal level of abatement. With climate change costs an order of magnitude larger than commodity costs, the theoretical first-best outcome would only be reached with additional environmental regulations.

While this paper focused on investor-owned utilities, it is worth thinking about other ownership structures. It is unlikely that municipal utilities are acting on the greenhouse gas implications of their actions. Given that they do not face competition, it is also plausible that they are under-incentivized to avoid leaked commodity costs. Empirical research on municipally run distributors would be worthwhile. A few lessons also apply for other components of the natural gas supply chain, such as production, processing, and transmission. The economic regulations and incentives faced by these firms are different from what we have described for distribution utilities. However, it is plausible that they face distorted incentives for leak abatement. For instance, oil producers located far from natural gas infrastructure may not face an incentive to capture methane leaks, leaving regulators to rely on flaring regulations. In any event, production, processing, and transmission firms do not currently internalize the greenhouse gas costs of their actions. Future research on these sectors to understand the level of abatement they have historically undertaken, compared to what a social planner would choose, would aid policy-makers.

[38] See the White House's "Climate Action Plan: Strategy to Reduce Methane Emissions," March 2014. https://www.whitehouse.gov/sites/default/files/strategy_to_reduce_methane_emissions_2014-03-28_final.pdf

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Appendix

In this Appendix, we provide additional tables and figures referred to in the main text. Table A1 provides additional summary statistics on the full sample of natural gas utilities.

Figure A1 compares the density of leak volumes as a percentage of total volume purchased for the full sample of utilities versus just those utilities reporting financial information. The measurement error appears to be substantially lower for the utilities reporting financial information – i.e., for the sub-sample used in our cost estimation.

Regressions Results: Lost Gas is Correlated with System Materials

In Section 2, we argue that the leak rate data are meaningful, in that they correlate with physical pipeline characteristics in intuitive ways. This was shown in the text with Figure 1. Here, we formalize the relationship with regressions (Table A2). We control for Census region-by-year effects and depending on the specification, state fixed effects or utility fixed effects. We examine the percent leaked (volume leaked as a function of total gas purchased), because utilities vary tremendously in the volumes they purchase. When comparing across utilities we find the leak rate increases significantly in pipeline age.[39] Each additional year increases the leak rate by 0.02 percentage points – Column (1) – with a standard error of less than 0.01. To put this in perspective, the average pipeline age is 26 years and the average leak rate is 1.6 percent, so the elasticity is 0.27. Moreover, the leak rate is decreasing in the portion of pipeline that is composed of either high-quality steel (coated and/or cathodically protected) or plastic. For each percentage point of high quality material, the leak rate declines by 0.02 percentage points. Alternatively, if a utility were to change from entirely low-quality to high-quality material, the leak rate would decline by 1.4 percentage points, or almost the mean value.

These results are robust to additional specifications, as shown in Columns (2) - (5).

[39]As mentioned, 14% of miles are reported as "unknown decade." Age in this regression is defined as the average age of the miles with a known vintage. Including the portion of unknown vintage as a separate explanatory variable does not change the results.

Much of the identifying variation is cross-sectional, since pipeline upgrades are slow. As such, including utility effects (Column 5) leads to very imprecise estimates; however the point estimates are qualitatively similar. Overall, these regressions indicate that, while the reported leak measure is noisy, it is highly correlated with measures of pipeline quality.[40] It is worth noting that, if the mean leak volume in these data is assumed to be correct, then emissions from the distribution system would be more than double the estimate reported by the federal government (in e.g. DOE 2015).

Robustness: Cost of Leak Abatement and Pipeline Replacement

This section provides additional results related to the estimation of the cost of leak abatement and pipeline replacement. Table A3 provides the full first stage results for the leak abatement regressions (the 2SLS results of which are shown in the text in Table 2). Table A4 provides the full set of 2SLS estimates, including the coefficients on controls.

Several tables provide alternative specifications for the regressions in Table 2, which estimate the cost of leak abatement. Table A5 shows alternative controls, a different sample, and a different dependent variable. Table A6 is identical to Table 2, but with capital expenditures rather than O&M expenditures. This table is designed to show that, while there are capital expenditures associated with leak detection and repair, they are small in levelized terms (as an approximation, for instance, the coefficients can be divided by 40, if the capital upgrade lasts 40 years and there is no discounting).

Table A7 replicates Table 2, but with subcategories of O&M spending. Each point estimate is from a separate regression. The rows list separate dependent variables (for instance, dollars spent on "Operations: Supervision and Engineering") and the columns designate different specifications. Mirroring specifications in Columns (1), (2), and (4) of Table 2, the OLS

[40] The measure of leaks consists of losses from leaks (sometimes using engineering estimates) and unaccounted for gas (the difference between metered gas purchased and metered gas sold). One valid concern with reported measures of losses from leaks is that the engineering estimates which some utilities report could be a function of pipeline age or material quality. We are less concerned, however, with the sum total of losses from leaks and unaccounted for gas: the difference between gas purchased and sold is not an engineering estimate.

and two separate sets of instruments are presented. This table serves two purposes. First, if a soft budget constraint applied, we would expect to see large and significant abatement costs for categories such as "Maintenance: Measuring and Regulating Stations, General" (an area targeted by the programs described in Table A12) offset by estimates with the opposite sign for other categories. This is not the case, providing evidence that the dependent variable used in Table 2 is appropriate. Second, it allows us to examine the areas where utilities appear to be achieving leak reductions. However, note that these estimates should NOT be used as the abatement cost associated with each activity, because the regressions are attributing *all* leak abatement to each subcategory of spending. Unfortunately, we do not have a way to separately identify leaks abated by one category versus another. Instead, the regressions can be used simply to get a qualitative sense of which categories are most closely correlated with the instrumental variables. Column (1) presents the OLS results and all estimates are very small. When instrumenting for leaked gas using financial-incentives, in Column (2), all estimates are noisy and most are small, consistent with the overall result in Table 2. In Column (3), where the effect is local to increased safety regulations, the categories showing statistically significant abatement costs are intuitive: "Operations: Customer Installation" (this may relate to Excess Flow Valve installation, which can mitigate damages from leaks by shutting down portions of the pipeline system), "Maintenance: Mains," "Maintenance: Measuring and Regulating Stations" (specifically, "General" and "Industrial"), "Maintenance: Services," "Maintenance: Meters and House Regulators," and "Operations: Other Expense." These are all categories matching components widely known to be susceptible to leaks – for instance, they are components targeted by the EPA's Gas STAR program.

Table A8 provides the first stage results for the pipeline replacement regressions (the 2SLS results are shown in the text in Table 3). Table A9 replicates Table 3 while also displaying the coefficients on all coefficients. Table A10 provides robustness checks for Table 3. Column (1) uses an alternative instrument. Column (2) includes O&M expenditures on the left-hand side. In this case, the IV does not satisfy the exclusion restriction, since the safety regulations induced O&M spending not related to pipeline upgrades – this column can be thought of as providing an upper bound. Column (3) includes all gas-related capital, not just distribution-specific gas-related capital. Column (4) uses an alternative definition of accumulated capital. Specifically, the dataset contains information on capital additions as well as total capital. In all columns, except Column (4), we use the sum total of capital additions between 1998 and 2013. In Column (4) we instead subtract total capital reported in 2013 from total capital in 1995 to obtain a measure of capital additions over the period. While data on new capital expenditures begin in 1998, data on capital stocks are available beginning in 1995. Column (5) drops all controls, and Column (6) uses an alternative sample period. Across these specifications, the cost of replacing low-quality pipe varies from $1.1 to 2.6 million per mile.

Table A11 provides results for the emissions factor estimation described in Section 3.2. As the text details, these results are noisy, so our analysis uses both the estimate given in Column (1) and an alternative estimate from the EPA. Column (2) shows a robustness check with a subsample of utilities that report financial information.

Table A12 assembles cost estimates for various leak detection and repair activities, provided by the EPA's Natural Gas STAR program, referred to in Section 3.1 of the main text. Similarly, Table A13 assembles reported pipeline replacement costs from a number of sources. This is referred to in Section 3.2 of the main text.

Estimating Safety Benefits

Table A14 shows our estimates of safety benefits from leak abatement. We regress damages (in dollars) on leaks (in Mcf) and low-quality mains (in miles). The damage variable is for safety incidents reported to PHMSA and combines values for property damages, injuries, and loss of life. We drop incidents caused by third-party excavation and outside forces, as these are outside the control of the utility. The first column shows the OLS results. Because of measurement error and the potential for unobservables to be correlated with the variables of interest, in the remaining columns we instrument for both leaks and miles using three instruments. In Columns (2)-(4), we use an indicator for utilities that are in California after the explosion in San Bruno; an indicator for Pacific Gas & Electric after San Bruno; and an interaction between the historical count of low quality mains (cast iron, ductile iron, and unprotected bare steel) and an indicator for the period after PHMSA regulations increased in stringency. In Columns (5)-(7), we use the count of known leaks pending leak repair at the end of the previous year as well as the low-quality, post-PHMSA interaction. In Columns (1), (2), and (5), the dependent variable is the aggregate of the total property damage and a Value of Statistical Life of $9.1 million per fatality. The third and sixth columns add injuries to the damage estimate, assuming $1 million per reported injury. The fourth and seventh column estimate the impact on accident counts, then assume a mean damage value per accident. The implied leak abatement benefits in $/Mcf for Columns (1)-(3) and (5)-(6) are simply equal to the coefficient on "Volume leaked, mcf." The implied leak abatement benefit for Column (4) and (7) assumes that the damage, conditional on an accident occurring and including injuries, is equal to $2.02 million (the sample average we observe). The implied pipeline benefits rows re-scale the coefficient on "Low-quality mains, miles" by an emissions factor, in Mcf/miles, of either 225 or 737.

Overall, the safety benefits of leak abatement are estimated to be at most $0.56/Mcf. The safety benefits of pipeline upgrades are quite noisy – this is not surprising given that the typical utility in our sample has one accident every ten years, ignoring third-party damages. The largest point estimate implies a benefit of $1.86/Mcf, although that is not statistically different from zero. We are reluctant to place too much emphasis on these estimates, because of the potential for underreporting as well as the potential for unobservable black swan events with right-tailed damages. However, we note a few things. First, the positive point estimates for the pipeline coefficient imply that the safety benefits of pipeline replacement are larger than the safety benefits of other leak abatement. This is intuitive, if old pipelines are closer to population centers than are, for instance, surface stations where leaks could be abated. The negative point estimates would yield the opposite conclusion, but they are for the OLS specification (which we are reluctant to rely upon) and for the specifications (Columns 4 and 7) that assume constant damages per incident. If pipeline-related incidents entail larger damages than other leak-related incidents, then these specifications are less appropriate than the specifications in Columns 2, 3, 5, and 6.

In Section 3.1, we concluded that utilities have been abating at a cost well below the theroetical socially optimal cost. This was based on point estimates of abatement costs of around \$0/Mcf and \$4.60/Mcf, depending on the instruments used. We then compared this to the commodity value that utilities faced (citygate prices in our estimation sample averaged \$7.44/Mcf, but many utilities were able to pass this through to retail customers). Moreover, society faces an additional cost of \$27/Mcf in climate change damages from methane leaks. Including safety benefits does not, as such, change the qualitative conclusion we reached, which is that leak abatement is currently well below the level that social planner might choose.

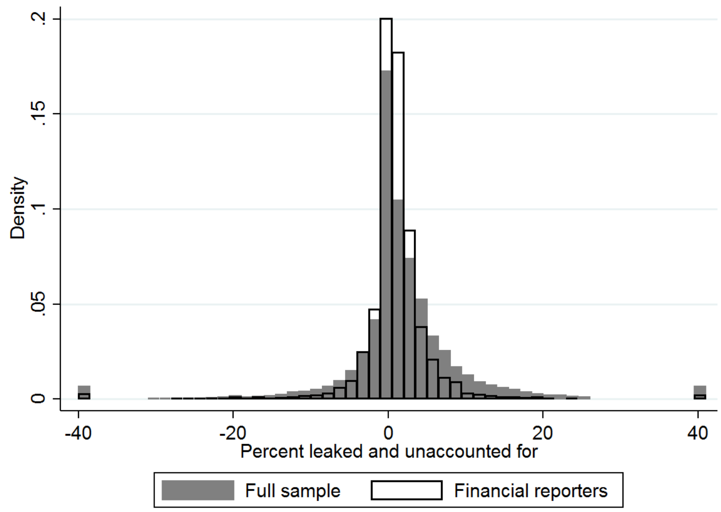
In Section 3.2, we concluded that the levelized cost of pipeline replacement (\$33/Mcf to \$261/Mcf, from Table 4) is well above the cost of historically undertaken leak detection and repair activities. In addition, our preferred set of parameters implied a levelized cost of abatement well above the value of commodity conserved and climate change damages avoided (around \$34/Mcf for our sample). However, we cautioned that pipeline replacement may entail greater safety benefits than would other leak detection and repair activities, and indeed our preferred estimates in Table A14 are consistent with this intuition. The largest value of safety benefits we estimate for pipeline replacement (\$1.86/Mcf) would likely not change our qualitative conclusions.

Overall, while we are reluctant to rely too heavily on these noisy estimates, we note that they appear to be small enough to not change our qualitative conclusions about the effective of the average mile of pipeline replacement. However, we maintain that heterogeneity is likely to matter, as we discuss in the main text.

Robustness: Incentives to Abate

Table A15 provides robustness checks for Table 5, on what is correlated with utility expenditures. We examine alternative controls (Column 2), an alternative regulatory measure (Column 3), a subsample (Column 4), and a log/log functional form (Column 5).

Figure A1: Percent Lost and Unaccounted for Gas, Financial Reporters versus Full Sample



Note: This histogram compares the density of leak volumes as a percentage of total volume purchased for the full sample of utilities versus just those utilities reporting financial information. The upper and lower 1 percent tails of the distribution have been censored at +/-40. A unit of observation is a utility-year combination, with around 1,500 utilities across 19 years (1995 to 2013). The data source is EIA via SNL, as described in the text.

Table A1: Summary Statistics from Full Sample

	Mean	Std. Dev.	Min.	Max.	N
Volume leaked, Bcf	0.17	2.05	-80	111	22,801
Volume leaked, %	1.71	3.70	-8.1	13	22,801
Volume purchased, Bcf	14.88	77.39	0	1,598	25,341
Pipeline mains, miles	842.77	3,271.49	0	117,734	23,751
Unprotected bare steel	43.40	289.98	0	5,979	23,752
Unprotected coated steel	14.80	168.97	0	5,638	23,752
Cathodically protected bare steel	11.34	175.74	0	20,221	23,752
Cathodically protected coated steel	347.83	1,618.34	0	117,734	23,752
Plastic	391.43	1,515.43	0	29,314	23,752
Cast iron	30.98	212.47	0	5,566	23,752
Other	2.96	119.95	0	15,831	23,751
Low-quality mains, %	4.24	11.88	0	100	23,640
Average pipeline age, years	25.72	13.59	-1	82	11,686
City-gate price, $/Mcf	6.80	2.46	1.8	34	35,663
Henry Hub price, $/Mcf	5.81	2.41	3	11	32,334

Notes: The full sample is a census of 1,580 natural gas distribution utilities. The financial reporters sample is composed of 240 large investor-owned utilities, representing 75% of total end user sales. Most variables are available for the period 1995-2013; but capital expenses data begin in 1998 and pipeline age data begin in 2004. The upper and lower five percent of leak rates have been trimmed, as described in the text. Low-quality mains refers to pipeline mains made of ductile iron, unprotected bare steel, and cast iron. Henry Hub prices are quoted in dollars per mmBtu; we assume a heat content of 1.025 mmBtu per Mcf. Prices and expenses are listed in 2015 dollars.

Table A2: Leak Rates

	(1) % Leaked	(2) % Leaked	(3) % Leaked	(4) % Leaked	(5) % Leaked
Average pipeline age, years	0.016***	0.017**	0.015***	0.017***	0.020
	(0.005)	(0.009)	(0.005)	(0.006)	(0.013)
Plastic or high-quality steel, %	-0.023***	-0.022*	-0.023***		-0.012
	(0.008)	(0.013)	(0.009)		(0.014)
Unprotected coated steel, %				-0.027**	
				(0.011)	
Cathodically protected bare steel, %				-0.034***	
				(0.010)	
Cathodically protected coated steel, %				-0.031***	
				(0.009)	
Plastic, %				-0.031***	
				(0.009)	
Cast iron, %				-0.016	
				(0.016)	
Ductile iron, copper, or other, %				-0.022*	
				(0.011)	
Region-year effects	Yes	Yes	Yes	Yes	Yes
State effects	Yes	Yes	Yes	Yes	No
Utility effects	No	No	No	No	Yes
Observations	9,424	10,206	8,140	9,424	9,424
R^2	0.09	0.06	0.09	0.09	0.03

Notes: The dependent variable is the percent of gas purchased that is leaked. All columns trim outliers of leak rates that are in the upper and lower 5%, with the exception of column (2) which trims only the upper and lower 1%. Column (3) excludes utilities that report 25% or more transmission, and utilities that had a large increase in customers, new pipes, or old pipes. In Column (4) the omitted category of pipeline type is unprotected, bare steel. Standard errors are clustered at the utility level. *** Statistically significant at the 1% level; ** 5% level; * 10% level.

Table A3: Instrumenting for Volume Leaked: First Stage

	Financial-Incentive Instruments		Safety-Incentive Instruments	
	(1) Vol. Leaked	(2) Vol. Leaked	(3) Vol. Leaked	(4) Vol. Leaked
Excluded Instrumental Variables:				
Lagged known pending leak repairs	-205.15***	-204.69***	-80.83	
	(60.95)	(60.86)	(154.63)	
City-gate price, $/Mcf		-97,066.49		
		(134,030.57)		
I(Cap on leak recovery)		1,501,284.71**		
		(724,080.44)		
I(Cap on leak recovery)×Citygate price		-376,421.18***		
		(119,618.91)		
Pre-period miles of low-quality mains×I(post-PHMSA)			-1,258.79***	-702.54**
			(481.23)	(340.86)
Pre-period miles of low-quality mains^2×I(post-PHMSA)			0.40***	0.24**
			(0.13)	(0.11)
I(California)×I(post-San Bruno accident)			-4,534,461.94	-879,718.28
			(3,082,990.70)	(1,568,838.76)
I(PG&E)×I(post-San Bruno accident)				-14,865,020.12***
				(1,771,246.23)
Included Exogenous Variables:				
Repaired accidental leaks	156.22	152.30	222.78	181.28
	(237.28)	(239.35)	(281.70)	(272.23)
Known pending leak repairs	360.52***	358.38***	287.15*	292.35*
	(137.10)	(137.53)	(157.15)	(150.33)
Pipeline mains, miles	405.18	405.27	563.61	571.76*
	(347.48)	(347.36)	(366.11)	(338.32)
Service lines, count	-12.80*	-12.85*	-15.15**	-13.73**
	(7.25)	(7.24)	(7.52)	(6.57)
Low-quality mains, miles	588.26	605.50	677.87	119.20
	(609.33)	(603.03)	(548.50)	(501.77)
Low-quality service lines, count	5.12	5.26	4.07	5.05*
	(3.38)	(3.34)	(2.80)	(2.81)
Volume purchased, Bcf	363.61	42.48	-1,202.40	4,780.35
	(9,974.59)	(10,097.14)	(9,408.67)	(10,335.82)
Region-year effects	Yes	Yes	Yes	Yes
Utility effects	Yes	Yes	Yes	Yes
Observations	2,372	2,372	2,058	2,230
Kleibergen-Paap F-stat.	11.33	12.17	7.16	67.56

Notes: Dependent variable is the endogenous regressor in Table 2: volume of leaked gas, Mcf. In Column (1) the excluded instrument is the number of known leaks pending and scheduled for repair at the end of the previous year. In Column (2) additional instruments are included: the price of natural gas at the citygate, whether the utility faces a binding constraint on how much of the leaked gas can be recovered, and an interaction between the two. In columns (3) and (4) instruments driven by safety regulations are used. "Pre-period miles of low-quality mains×I(post-PHMSA)" is an interaction between the 1995 count of miles of low quality mains (cast iron, ductile iron, and unprotected bare steel) and an indicator for the period after PHMSA regulations increased in stringency; "I(California)×I(post-San Bruno accident)" is an indicator for utilities that are in California after the explosion in San Bruno; "I(PG&E)×I(post-San Bruno accident)" is an indicator for the utility responsible for the explosion, after the explosion. Controls are the count of repaired leaks caused by outside forces, third party sources, or excavation; the number of known leaks pending at the end of the current year; total miles of pipeline mains; total service line counts; total miles and service counts made of unprotected bare steel and cast iron; and total volume purchased. *** Statistically significant at the 1% level; ** 5% level; * 10% level.

Table A4: Abatement Costs: Operations and Maintenance Expenditures, All Coefficients

	OLS	Financial-Incentive Instruments		Safety-Incentive Instruments	
	(1) O&M	(2) O&M	(3) O&M	(4) O&M	(5) O&M
Volume leaked, Mcf	-0.23**	-0.88	0.29	-4.56***	-4.60***
	(0.11)	(1.54)	(1.47)	(1.25)	(0.85)
Included Exogenous Variables:					
Repaired accidental leaks	-1,630.03*	-1,635.96	-1,822.64*	-1,150.59	-982.90
	(971.52)	(1,010.60)	(1,007.51)	(1,589.98)	(1,614.49)
Known pending leak repairs	1,224.23	1,472.99	1,173.16	2,392.42*	2,353.31**
	(814.70)	(975.55)	(934.07)	(1,248.23)	(1,191.98)
Pipeline mains, miles	-2,723.26*	-2,939.52*	-3,395.71**	-1,598.24	-568.13
	(1,399.97)	(1,722.77)	(1,718.49)	(3,038.95)	(2,763.21)
Service lines, count	74.88**	77.31*	92.10**	32.70	17.12
	(34.61)	(43.51)	(44.70)	(64.67)	(58.80)
Low-quality mains, miles	175.82	-350.93	-1,119.57	2,441.65	2,158.41
	(4,702.32)	(4,820.39)	(4,938.52)	(4,947.13)	(4,991.45)
Low-quality service lines, count	-38.68***	-36.18***	-42.07***	-17.65	-13.46
	(12.61)	(14.03)	(15.30)	(18.63)	(17.23)
Volume purchased, Bcf	41,193.78	37,714.38	36,678.22	37,145.71	42,808.21
	(49,494.19)	(50,032.10)	(50,718.10)	(62,231.85)	(62,322.01)
Region-year effects	Yes	Yes	Yes	Yes	Yes
Utility effects	Yes	Yes	Yes	Yes	Yes
Observations	2,598	2,372	2,372	2,058	2,230
Kleibergen-Paap F-stat.	.	11.33	12.17	7.16	67.56

Notes: Displays unreported coefficients in Table 2. *** Statistically significant at the 1% level; ** 5% level; * 10% level.

Table A5: Abatement Costs: Operations and Maintenance Expenditures, Robustness Checks

	Instrument: Pending, Known Leaks				
	(1) O&M	(2) O&M	(3) O&M	(4) O&M	(5) O&M+Contractors
Volume leaked, Mcf	-1.15	-1.46	-0.31	-0.22	-0.49
	(1.42)	(1.76)	(2.26)	(1.45)	(2.25)
Observations	2,372	2,372	2,372	2,339	1,637
Kleibergen-Paap F-stat.	12.24	6.42	10.01	11.90	3.54
	Instruments: Safety Incentives				
	(1) O&M	(2) O&M	(3) O&M	(4) O&M	(5) O&M+Contractors
Volume leaked, Mcf	-4.83***	-6.03***	-5.31***	-4.58***	-7.91***
	(1.19)	(1.11)	(1.07)	(1.17)	(1.12)
Observations	2,058	2,058	2,058	2,028	1,395
Kleibergen-Paap F-stat.	7.00	4.06	5.64	7.64	5.95
Utility effects	Yes	Yes	Yes	Yes	Yes
Region-year effects	No	Yes	Yes	Yes	Yes
Year effects	Yes	No	No	No	No
3rd order polynomial of supply	No	Yes	No	No	No
Service Lines	Yes	Yes	No	Yes	Yes
Low-quality service lines	Yes	Yes	No	Yes	Yes

Notes: Robustness checks for columns (1) and (3) from Table 2. First panel uses the instrument in column (1) of Table A3: known leak repairs still pending repair at the end of the previous year. Second panel uses the instruments in column (3) of Table A3: known leaks still pending repair at the end of the previous year; an interaction between the 1995 count of miles of low quality mains and an indicator for the period after PHMSA regulations increased in stringency; this interaction squared; and an indicator for utilities that were in California after the explosion in San Bruno. Columns (1), (2), and (3) show modifications to the set of controls. Column (4) excludes LDCs that do not sell natural gas, but only distribute it on behalf of a third party. Column (5) also includes in the dependent variable the expenditures made on employment for outside services. *** Statistically significant at the 1% level; ** 5% level; * 10% level.

Table A6: Abatement Costs: Capital Expenditures

	OLS	Financial-Incentive Instruments		Safety-Incentive Instruments	
	(1) Capital	(2) Capital	(3) Capital	(4) Capital	(5) Capital
Volume leaked, Mcf	-0.15	-14.82***	-10.27**	-2.77	-5.80
	(0.21)	(4.91)	(4.58)	(4.99)	(3.81)
Controls	Yes	Yes	Yes	Yes	Yes
Region-year effects	Yes	Yes	Yes	Yes	Yes
Utility effects	Yes	Yes	Yes	Yes	Yes
Observations	2,186	2,093	2,093	1,816	1,871
Kleibergen-Paap F-stat.	.	21.78	21.67	14.42	96.20

Notes: Coefficients represent the amount spent, in $ per Mcf, to reduce natural gas leaks using capital expenditures. Dependent variable is the utility's expenditures on capital. The volume of leaked gas is instrumented for using the instruments in Table A3. The instrument in column (2) is the number of known leaks still pending repair at the end of the previous year. In column (3) additional instruments are included: the price of natural gas at the citygate, whether the utility faces a binding constraint on how much of the leaks can be recovered in rates, and an interaction between the two. Instruments in columns (4) and (5) are driven by safety regulations. In column (4) the instruments are the number of known leaks still pending repair at the end of the previous year; an interaction between the 1995 count of miles of low quality mains (cast iron, ductile iron, and unprotected bare steel) and an indicator for the period after PHMSA regulations increased in stringency; this interaction squared; and an indicator for utilities that were in California after the explosion in San Bruno. In column (5) the instruments are an interaction between the 1995 count of miles of low quality mains and an indicator for the period after PHMSA regulations increased in stringency; this interaction squared; and an indicator for utilities that were in California after the explosion in San Bruno; and an indicator for the utility responsible for the explosion, after the explosion. Controls are the count of repaired leaks caused by outside forces, third party sources, or excavation; the number of known leaks pending at the end of the current year; total miles of pipeline mains; total service line counts; total miles and service counts made of unprotected bare steel and cast iron; and total volume purchased. Standard errors are clustered by utility. *** Statistically significant at the 1% level; ** 5% level; * 10% level.

Table A7: Subcategories of Operations and Maintenance Expenditures

Category	OLS (1) Estimate, \$/Mcf	Financial-Incentive IV (2) Estimate, \$/Mcf	Safety-Incentive IV (3) Estimate, \$/Mcf
Operations: Supervision & Engineering	0.028**	-0.329	0.123
	(0.013)	(0.821)	(0.312)
Operations: Distr Load Dispatching	0.001**	0.083*	0.008
	(0.002)	(0.048)	(0.014)
Operations: Compressor Station Labor	0.00**	0.01*	00
	(0.0)	(0.008)	(0.002)
Operations: Compressor Stat Fuel & Power	0.00**	0.001*	0.00
	(0.0)	(0.002)	(0.0)
Operations: Mains & Services	-0.028**	-0.187*	-0.109
	(0.018)	(0.476)	(0.234)
Operations: Meas & Reg Station, General	0.007***	0.116*	0.082
	(0.003)	(0.092)	(0.074)
Operations: Meas & Reg Station, Industrial	0.01***	-0.121*	-0.02*
	(0.003)	(0.099)	(0.012)
Operations: Meas & Reg Station, City Gate	0.00***	0.005*	-0.008*
	(0.0)	(0.047)	(0.006)
Operations: Meter & House Regulator	0.025***	4.816*	0.559*
	(0.046)	(3.263)	(0.426)
Operations: Customer Installation	-0.089***	-4.262*	-2.278***
	(0.022)	(3.011)	(0.471)
Operations: Other Expense	-0.254***	-0.31*	-2.171***
	(0.058)	(0.417)	(0.515)
Operations: Rents	0.001***	-0.014*	0.001***
	(0.003)	(0.078)	(0.022)
Maintenance: Supervision & Engineering	-0.001***	0.122*	-0.063***
	(0.009)	(0.328)	(0.084)
Maintenance: Structures & Improvements	-0.004***	1063*	0.049***
	(0.003)	(0.86)	(0.046)
Maintenance: Mains	-0.118***	-2.387*	-1.251***
	(0.021)	(1.675)	(0.457)
Maintenance: Compressor Station Equipment	0.00***	-0.017*	-0.014***
	(0.0)	(0.024)	(0.011)
Maintenance: Meas & Reg Station, General	-0.015***	-0.633*	-0.267***
	(0.002)	(0.524)	(0.057)
Maintenance: Meas & Reg Stat, Industrial	-0.031***	-0.508*	-0.334***
	(0.007)	(0.342)	(0.116)
Maintenance: Meas & Reg Station, City Gate	0.00***	-0.036*	-0.018*
	(0.001)	(0.055)	(0.01)
Maintenance: Services	-0.04***	1.807*	-0.197*
	(0.011)	(1.394)	(0.132)
Maintenance: Meters & House Regulators	-0.02**	0.159*	-0.144*
	(0.008)	(0.168)	(0.085)
Maintenance: Other Equipment	0.028**	-0.059*	0.039*
	(0.012)	(0.121)	(0.022)

Notes: Each point estimate is obtained from a separate regression. The rows vary by dependent variable, covering the comprehensive list of subcategories of distribution O&M expenditures. The columns vary depending on the specification, and mirror the specifications in Table 2, Columns (1), (2), and (4). The first column is the OLS specification, and remaining two instrument for the quantity of leaked gas following the instruments in Table 2 Columns (2) and (4), respectively. The point estimates refer to the coefficient on volume of leaked gas.

Table A8: Instrumenting for Pipeline Replacement: First Stage of Capital Cost Regression

	(1) Low Quality Mains Replacement
Excluded Instrumental Variables:	
Historic low-quality mains, miles	0.28***
	(0.03)
Included Exogenous Variables:	
Δ volume purchased, Bcf	3.29
	(17.17)
Δ volume purchased - quadratic, Bcf	-0.80
	(0.78)
Δ volume purchased - cubic, Bcf	0.01
	(0.01)
Δ mains, miles	-0.01
	(0.03)
Δ customers	0.00
	(0.00)
Region effects	Yes
Observations	114
Kleibergen-Paap F-stat.	80.37

Notes: Results show the first stage regression corresponding to Table 3. Dependent variable is the replacement of low quality mains from 1998 to 2013. The instrument is the miles of low quality mains in 1995. Robust standard errors in parentheses. *** Statistically significant at the 1% level; ** 5% level; * 10% level.

Table A9: Cost of Pipeline Replacement, All Coefficients

	Total Capital Expenditures, 1998-2013 ($000)	
	(1) OLS	(2) IV
Low-quality main replacement, miles	1,112.17***	1,488.54***
	(208.36)	(277.42)
Controls:		
Δ volume purchased, Bcf	-29,123.60	-3,907.27
	(38,216.54)	(35,703.55)
Δ volume purchased - quadratic, Bcf	1,397.74	1,078.67
	(1,377.13)	(1,281.94)
Δ volume purchased - cubic, Bcf	-2.59	-0.24
	(8.25)	(7.84)
Δ mains, miles	67.42**	72.30**
	(28.27)	(35.48)
Δ customers	2.82***	1.89**
	(0.70)	(0.87)
Region effects	Yes	Yes
Observations	119	114
Kleibergen-Paap F-stat.	.	80.37

Notes: This replicates Table 3 while displaying the coefficients on the controls. Robust standard errors in parentheses. *** Statistically significant at the 1% level; ** 5% level; * 10% level.

Table A10: Alternative Specifications: Cost of Pipeline Replacement

	Total Expenditures, 1998-2013 ($000)					
	(1)	(2)	(3)	(4)	(5)	(6)
	Capital	Total	Capital	Capital	Capital	Capital
Low-quality main replacement, miles	1,789.50***	2,556.58***	1,653.29***	1,113.02***	1,738.25***	1,968.29***
	(608.61)	(419.29)	(305.81)	(253.24)	(266.67)	(360.06)
Observations	114	114	114	81	120	122
Kleibergen-Paap F-stat.	14.24	80.37	80.37	66.16	89.58	77.70

Notes: Column (1) uses as the instrument the portion of miles that were low-quality in 1995. Column (2) includes O&M in addition to Capital. Column (3) includes all gas-related capital, not just distribution-specific gas-related capital. Column (4) uses an alternative definition of capital; see text. Column (5) has no controls. Column (6) uses data from 2004 to 2013. Robust standard errors in parentheses. *** Statistically significant at the 1% level; ** 5% level; * 10% level.

Table A11: Volume Leaked on Miles Replaced

	(1)	(2)
	Volume Leaked	Volume Leaked
Lagged low-quality mains, miles	899.62	1,186.50
	(794.43)	(846.05)
Lagged medium quality mains, miles	300.84	570.27
	(227.19)	(378.72)
Volume purchased, Bcf	5,813.79	3,552.78
	(8,929.34)	(12,104.80)
Volume purchased^2	47.84*	51.66**
	(25.36)	(24.48)
Volume purchased^3	-0.05***	-0.05***
	(0.01)	(0.01)
Lagged pipeline mains, miles	-203.26	-341.83
	(192.12)	(261.07)
Repaired accidental leaks	86.66	-22.20
	(265.37)	(268.65)
Region-year effects	Yes	Yes
Utility effects	Yes	Yes
Observations	17,421	2,440
R^2	0.02	0.02

Notes: Dependent variable is the volume of leaked gas (Mcf). Column (1) includes all data, not only the financial reporters, and Column (2) only includes financial reporters. Coefficient on “Lagged low-quality mains” in Column (1) serves as the emissions factor of gas leaked per mile of low-quality pipe, Mcf/mile. Standard errors are clustered by utility. Low-quality mains are those constructed of cast iron, ductile iron, or unprotected bare steel and medium-quality mains are those constructed of copper, unprotected coated steel, or cathodically protected bare steel. Standard errors are clustered by utility. *** Statistically significant at the 1% level; ** 5% level; * 10% level.

Table A12: Reported Leak Detection and Repair Costs

Type	Estimate, \$/Mcf
Reducing blowdown:	
Repairing valves during other repairs	\$1.20
Composite wrap to prevent repairs	\$1.43
Improved control system to reduce compressor start-ups	\$2.19
Hot taps to reduce blowdown	\$3.93
Capturing vented gas	\$5.55-6.67
Repairing leaks from compressors and pipes:	
Flexible plastic liners	offset
Compressor stations	\$0.89
Pneumatic devices, retrofit	\$2.93
Pneumatic device, early replacement	\$7.11
More frequent walking surveys	\$7.33
Excess flow valves	\$39.38
Reducing system pressure:	
Manually	\$1.95
Automated	depends

Notes: Source is EPA's Natural Gas STAR program. All are 2009-2015. Accessed February 16 2016 from various "Fact Sheets" at the EPA's "Recommend Technologies and Practices – Natural Gas STAR Program" website, https://www3.epa.gov/gasstar/tools/recommended.html.

Table A13: Reported Pipeline Replacement Costs

Type	Source	Estimate
Mains, Florida	PUC[1]	170,000 - 190,000
Cast iron, Allentown	Newspaper[2]	650,000
Cast iron, OH and KY	Duke[3]	670,000
Cast iron, Philadelphia	NPR[4]	1 million
Mains, Pennsylvania	PUC[5]	200,000 - 1.8 million
Bare steel, Ohio and New England	Analysis Group[6]	300,000 - 1.2 million
Mains, Philadelphia	PUC[5]	1.5 million
Cast iron, urban areas	ICF for EDF[7]	1 - 3 million
Cast iron	AGA[8]	1.5 - 2.1 million

Notes: All are 2009-2015. Sources: [1]Florida Public Service Commission, Docket No 140166-GU. Order No PSC-14-0693-TRF-GU. Issued December 15, 2014. [2]www.lehighvalleylive.com. 2012. "Allentown, UGI differ over whether pace of gas pipeline replacement is enough." [3]Duke Energy. 2012. "Lessons Learned from an Accelerated Main Replacement Program." [4]NPR. 2014. "Report: Philadelphia gas utility second worst for pipeline leaks." [5]Pennsylvania Public Utility Commission. Staff Report. "Inquiry into Philadelphia Gas Works' Pipeline Replacement Program." April 2015. [6]Aubuchon, Craig and Hibbard, Paul. "Summary of Quantifiable Benefits and Costs Related to Select Targeted Infrastructure Replacement Programs." Analysis Group, Inc. January, 2013. [7]ICF International. 2014. "Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries." Prepared for the Environmental Defense Fund. [8]American Gas Association website: https://www.aga.org/content/estimation-replacement-national-cast-iron-inventory-2012. Accessed April 19 2016.

Table A14: Damages, from Accidents

	OLS	IV			IV		
	(1) Property+ Fatalities ($)	(2) Property+ Fatalities ($)	(3) Property+ Fatalities+ Injuries ($)	(4) Count (Million)	(5) Property+ Fatalities ($)	(6) Property+ Fatalities+ Injuries ($)	(7) Count (Million)
Volume leaked, Mcf	-0.01	0.06***	0.10***	0.06***	0.33	0.56*	0.26**
	(0.01)	(0.02)	(0.02)	(0.02)	(0.23)	(0.29)	(0.10)
Low-quality mains, miles	-105.38	243.40	91.81	-475.46	417.75	344.54	-283.71
	(151.09)	(800.80)	(939.51)	(682.65)	(1,394.56)	(1,990.16)	(1,055.37)
Controls	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Region-year effects	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Utility effects	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Observations	6,058	5,518	5,518	5,518	5,014	5,014	5,014
Kleibergen-Paap F-stat.	.	37.10	37.10	37.10	4.47	4.47	4.47
Implied leak abatement benefit, $/Mcf	-0.01	0.06***	0.10***	0.13***	0.33	0.56*	0.52**
	0.01	0.02	0.02	0.04	0.23	0.29	0.21
Implied pipeline benefit, $/Mcf, F=225	-0.47	1.08	0.41	-4.27	1.86	1.53	-2.55
	(0.67)	(3.56)	(4.18)	(6.13)	(6.20)	(8.85)	(9.47)
Implied pipeline benefit, $/Mcf, F=737	-0.14	0.33	0.12	-1.30	0.57	0.47	-0.78
	(0.21)	(1.09)	(1.27)	(1.87)	(1.89)	(2.70)	(2.89)

Notes: These seven Columns estimate the monetary damages from distribution pipeline accidents, i.e., the safety-related benefits of accident prevention. Each Column is a regression of monetary damages on leaks and on low-quality miles. Columns (2)-(4) instrument for both explanatory variables using an indicator for utilities that are in California after the explosion in San Bruno; an indicator for Pacific Gas & Electric after San Bruno; and an interaction between the historical count of low quality mains and an indicator for the period after PHMSA regulations increased in stringency. Columns (5)-(7) instrument for both explanatory varaibles using the count of known leaks pending leak repair at the end of the previous year and an interaction between the historical count of low quality mains and an indicator for the period after PHMSA regulations increased in stringency. Columns (1), (2), and (5) aggregate property damages and lost lives, using a Value of a Statistical Life of $9.1 million. Columns (3) and (6) adds injuries, assuming a value of $1 million per injury. Columns (4) and (7) use the accident count, re-scaled, as the dependent variable. The implied leak abatement benefits in $/Mcf for Columns (1)-(3) and (5)-(6) are simply equal to the coefficient on "Volume leaked, Mcf." The implied leak abatement benefit for Columns (4) and (7) assumes that the damage, conditional on an accident occurring and including injuries, is equal to $2.02 million (the sample average we observe). The implied pipeline benefits re-scale the coefficient on "Low-quality mains, miles" by an emissions factor, in Mcf/miles, of either 225 or 737. All four specifications control for: region-year effects; a San Bruno indicator (PG&E in 2010); a count of repaired leaks caused by outside forces, third party sources, or excavation; the number of known leaks pending at the end of the current year; total miles of pipeline mains; and total volume purchased. Sample includes only utilities that ever reported an accident. Standard errors, in parentheses, are clustered by utility. *** Statistically significant at the 1% level; ** 5% level; * 10% level.

Table A15: Alternative Specifications: What Explains Utility Expenditures

	Expenditures ($ millions)				
	(1)	(2)	(3)	(4)	(5)
Economic and Regulatory Variables:					
City-gate price, $/Mcf	-3.34**	-3.02*	-3.52**	-2.53*	-0.15
	(1.46)	(1.64)	(1.42)	(1.38)	(0.14)
Lagged known pending leak repairs, thousands	0.91	0.93	0.90	1.26	0.01**
	(2.39)	(2.71)	(2.41)	(2.83)	(0.00)
Fraction of year in a rate case	12.68***	13.46***	12.77***	10.47***	0.09***
	(4.41)	(4.47)	(4.42)	(3.57)	(0.03)
Fraction of year in a rate-case test year	8.23***	10.04***	8.12***	8.12***	0.05**
	(2.99)	(3.30)	(2.99)	(2.83)	(0.03)
I(Utility has pipeline rider)	-4.76	-4.25		-5.57	0.02
	(5.42)	(5.37)		(6.58)	(0.12)
I(Nearby state has pipeline rider)			-3.02		
			(3.51)		
Low-quality mains, thousands of miles*I(post-PHMSA)	30.72**	26.67**	30.87**	35.44**	0.03
	(13.50)	(12.38)	(13.64)	(15.14)	(0.05)
Low-quality mains, thousands of miles^2*I(post-PHMSA)	-3.75	-3.08	-3.83	-5.17	-0.02
	(3.08)	(2.95)	(3.12)	(3.16)	(0.03)
I(California)×I(post-San Bruno accident)	110.85*	116.21*	110.73*	91.12*	0.24**
	(60.23)	(61.47)	(60.32)	(53.87)	(0.10)
Controls:					
Repaired accidental leaks, thousands	6.29	6.03	6.34	16.82**	0.02*
	(4.56)	(4.85)	(4.57)	(7.01)	(0.01)
Known pending leak repairs, thousands	0.46	0.83	0.54	0.29	0.01
	(2.30)	(2.37)	(2.29)	(2.10)	(0.00)
Mains, thousands of miles	4.05	4.57	4.12	17.76***	0.18***
	(2.50)	(2.92)	(2.53)	(6.25)	(0.05)
Volume purchased, Bcf	-0.08	-0.09	-0.08	-0.07	-0.02
	(0.17)	(0.17)	(0.17)	(0.25)	(0.02)
Region-year effects	Yes	No	Yes	Yes	Yes
Year effects	No	Yes	No	No	No
Utility effects	Yes	Yes	Yes	Yes	Yes
Observations	1,799	1,799	1,799	1,520	1,799
R^2	0.34	0.31	0.34	0.37	0.07

Notes: Dependent variable is the sum total of capital and O&M expenditures in millions of dollars. Column (1) shows the specification given in Table 5. Column (2) uses year effects. Column (3) replaces "Utility has a pipeline rider" with "Nearby state has a pipeline rider." Column (4) excludes utilities that report 25% or more transmission, and utilities that had a large increase in customers, new pipes, or old pipes. Column (5) is run in logs. Standard errors are clustered by utility. *** Statistically significant at the 1% level; ** 5% level; * 10% level. "