Price Regulation and Environmental Externalities: Evidence from Methane Leaks

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Abstract

We estimate how much US natural gas distribution firms spend to reduce methane leaks. Methane is a significant contributor to climate change, so the wedge between the private and social benefits of abatement is large. Moreover, incentives to abate leaks are additionally weakened by this industry being a regulated natural monopoly: current price regulations allow many distribution firms to pass the cost of any lost gas on to their customers. Our estimates imply that too little is spent *repairing* leaks. In contrast, accelerated pipeline *replacement* cannot in general be justified by climate benefits alone.

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 US natural gas supply chain result in roughly $8 billion dollars of climate impacts annually.[1] The US 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 analyze leak abatement incentives at the natural gas distribution firms that deliver gas to end-user customers. This is a sector that is not covered by recent federal methane regulations, and it has had limited emissions reductions to date.[2] The academic literature that does exist 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).[3] 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 US government on leaks from natural gas distribution companies. This is a contribution in its own right. Some analysts have shied away from these data because of measurement error (Kirchgessner et al., 1997; ICF International, 2014), however we provide empirical strategies that address the data quality issues.

Leaks can occur from faulty connections, decaying infrastructure, or intentional venting at every stage of the supply chain: extraction, storage, transmission, and distribution. We

[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. Below we discuss this approach relative to using Marten et al. (2015)'s estimates of the social cost of methane.

[2]See the May 2016 final rule to reduce methane from the oil and natural gas industry, https://www.epa.gov/stationary-sources-air-pollution/epas-actions-reduce-methane-and-volatile-organic-compound-voc.

[3]White papers and non-academic reports on methane leaks and aging pipelines include Aubuchon and Hibbard, 2013; Costello, 2012; Costello, 2013; Department of Energy, 2015; Yardley Associates, 2012; ICF International, 2014; Webb, 2015.

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 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. By regulating prices, 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. Leaked gas is treated as a cost of doing business; a 1935 Supreme Court decision stated that "a certain loss [of natural gas] is unavoidable, no matter how carefully business is conducted."[4] We are able to observe how much the investor-owned utilities spend each period, as well as how much gas is leaked. We obtain an estimate of the cost that utilities undertake to reduce leaks and compare it to value of the lost commodity (the price the utility paid for the gas). 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.

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.[5] In contrast, the ratio of social to private cost is a little less than three for combusted coal and less than two for combusted 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 gas market (Hausman and Kellogg, 2015; Mason, Muehlenbachs

[4]West Ohio Gas Co. v. Public Utilities Commission of Ohio, January 7, 1935.

[5]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 CO_2 and local pollutant emissions, is a bit less than twice the private cost of the gas (Parry et al., 2014).

and Olmstead, 2015; Covert, Greenstone and Knittel, 2016), this margin for climate change policy is taking on greater importance. Moreover, if the gas accumulates (for instance, in a building), it poses a risk of explosion – 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.[6] 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 estimate the cost of abatement undertaken using an instrumental variables strategy. In particular, we leverage variation stemming from the increased stringency of pipeline regulations for the distribution sector in 2010. As we describe later, the academic literature on regulated utilities has largely ignored natural gas firms, so no previous estimates of abatement costs exist. 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. Armed with our estimate of how much utilities are spending to reduce leaks and the commodity cost of the leaks, we can test whether the firm is equating abatement costs with abatement benefits. Utilities can abate in a myriad of ways, which we divide into methods that rely on operations and maintenance (O&M) procedures that leave pipeline infrastructure intact, and methods involving capital expenditures that replace aging pipelines.

In examining O&M expenditures, we find that utilities spend less for leak repairs than the value of lost gas itself, implying that they do not fully take advantage of cost-effective leak mitigation opportunities. 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 underlying our findings appears to be that utilities are reimbursed for leaked gas through their retail rates.[7] Our O&M

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

[7]It is, of course, possible that a non-regulated firm could fail to cost-minimize because of inattention or distorted managerial incentives (Allcott and Greenstone, 2012; Gillingham and Palmer, 2014; Gosnell, List

cost estimate 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 a levelized cost of capital-intensive abatement in the form of pipeline upgrades. To do so, we estimate two parameters: (1) a per-mile cost of pipeline replacement, and (2) a per-mile 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 expenditures made on pipeline replacement as a levelized cost. We provide a range of cost estimates, documenting reasons to suspect heterogeneity. The entire range of capital-intensive abatement expenditures is substantially higher than the O&M-intensive abatement expenditures. However, some capital-intensive expenditures are lower than the social cost of leaked gas, implying that moving pipeline replacement forward in time in order to abate greenhouse gas emissions appears to pass a cost/benefit test under some parameter combinations (but not under all). 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 regulations, rather than with a non-regulatory financial incentive such as commodity cost – despite tremendous identifying variation in recent years in these costs. This is consistent with industry reports,

and Metcalfe, 2016). Our setting does not allow us to test for this, as all of the utilities delivering natural gas are either price-regulated or government-operated. However, we note that the empirical evidence for firms is mixed. In addition, in contrast to much of the literature examining the failure of firms to efficiently manage their energy inputs, the *sole* business of the firms we observe is the delivery of energy to end-use customers. That is, their entire business model is based on acquiring, transporting, and delivering natural gas (and possibly also electricity) to customers; as such, one would expect them to have greater expertise in, and attention to, the efficient management of their natural gas inputs.

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). Perhaps the most closely related paper is Borenstein, Busse and Kellogg (2012), which documents inefficiencies in regulated distributors' natural gas procurement, specifically in the forward market. We contribute to this literature by examining in depth the impact of the regulatory structure on the operational decisions of a large sample of US utilities. To do so, we construct a dataset of a comprehensive set of variables, including utility expenditures, pipeline infrastructure, regulatory proceedings, and safety incidents.

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 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, in the spirit of Borenstein, Busse and Kellogg (2012). 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.[8] 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 may be "low-hanging fruit" for climate policy. 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; Gillingham and Palmer, 2014). 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.

Section 1 provides background on natural gas utilities and regulations. Section 2 describes the data sources, with a detailed description of the data on leaked gas. 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

[8]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).

to homes and businesses accelerated after World War II. Every year, over 7,000 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 and served 72 million customers.[9]

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 remote sensing and atmospheric models (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 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).

The Department of Energy recently reported that 32 percent of methane emissions from the natural gas system are 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

[9]Distribution volumes totaled over 15 billion thousand cubic feet (Mcf), and the average price paid by utilities in 2013 was \$4.97/Mcf. Customer counts are comprised of 67 million residential, 5 million commercial, and almost 200 thousand industrial and electric power customers.

from transmission, 2 percent from gathering and processing, and less than 1 percent from distribution.[10] 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.[11]

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. 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, Manhattan, and Washington, D.C.,

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

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

which have especially high concentrations of cast iron and bare steel pipe (Phillips et al., 2013; Jackson et al., 2014*a*; Gallagher et al., 2015; 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 15 percent from 2004 to 2013.[12] 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 20 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 almost 15 percent since 2004, a combination of pipeline replacement as well as better data collection on age. At EPA emissions factors, we estimate that pipeline replacements since 2004 have saved 5 million Mcf annually in leaks, worth around 130 million dollars annually in climate change benefits and over 30 million dollars in gas costs. Below, we examine the cost-effectiveness of these programs relative to other forms of abatement.

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, is equal to the citygate price of natural gas. In 2015, this averaged $4.25/Mcf. Over our sample (1995-2013), this averaged $6.75/Mcf for all utilities and $7.14/Mcf for the investor-owned utilities on which we focus. The second benefit of leak abatement is averted climate change impacts. At a social cost of carbon of $41/ton and a global warming potential (GWP) of 34, this is equal to around $27/Mcf.[13] The final benefit is averted explosions, which we estimate in $/Mcf terms (the estimates are very noisy, but all are less than $2.74/Mcf).

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

[13]Throughout we use a GWP-scaling approach, rather than Marten et al. (2015)'s estimate of the social cost of methane. An advantage of the Marten et al. approach is that it directly estimates the social cost of methane rather than simply scaling by a GWP. A disadvantage is that it relies on IPCC Fourth Assessment Report (AR4) rather than AR5 results (Interagency Working Group, 2016), and it has not yet been updated to reflect the significantly higher GWPs used in AR5.

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. Information sheets for this program tend to cite benefits related to greenhouse gas impacts as well as operational efficiency.[14]

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 has issued a final rule for cutting methane emissions from new sources in the upstream oil and gas industry and is in the process of issuing regulations from existing sources. The distribution sector, however, is not included.

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

[14] 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.

forms in this context: some utilities are investor-owned utilities facing price regulations, and other utilities are owned and operated by municipal governments.[15]

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 leak repair 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 mechanisms to recover costs without a regulatory proceeding have been introduced in some states, 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 fully incentivized to reduce leaks. Leaked gas is typically recovered in the same mechanism that is used to recover gas purchases, called a purchased gas adjustment (PGA). Specifically, utilities, "in their PGA mechanisms, generally divide the total gas-purchased costs by the volume of gas sold to customers... By calculating the PGA mechanism based on sales, the utility is implicitly building in the LAUF [lost and unaccounted for]-gas factor" (Costello, 2013). 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 utility commissions "What incentive does your commission provide utilities to manage LAUF gas?," and 19 of 41 responded "None"

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

or something similar (Costello, 2013). Lost and unaccounted for gas (LAUF) is the only widely available measure of leaks and is simply 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).

We note that utilities are also able to recover costs of leak repairs, since O&M and capital costs are also reimbursed via retail rates. It is theoretically possible, then, that a utility would be exactly indifferent between repairing and not repairing. If any uncompensated managerial effort or attention is required, however, then the utility would be under-incentivized to repair, a la Fabrizio, Rose and Wolfram (2007).

Finally, an additional distortion is possible, which we explore below. Averch and Johnson (1962) point out that, because utilities are allowed to earn a fair rate of return on their capital investments but not on their labor or other variable costs, the utilities' input choices can be distorted away from the efficient allocation.

The economic regulations faced by utilities may lower the incentive to repair leaks, but on the other hand, the safety regulations described previously are likely to raise the incentive. As such, whether cost-effective abatement opportunities are left on the table remains an open question. Below, we empirically examine the impact of the economic and safety regulations on utility behavior. We also examine the validity of using lost and unaccounted for gas as a proxy for leaks. Finally, we look for the possibility of an Averch-Johnson effect in input choices.

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. This census contains annual data for all utilities on volumes of gas purchased and delivered.[16] For deliveries, volumes are broken down by sector (residential, commercial, industrial, electric power, other). At the sectoral level, we also observe revenue and the number of customers 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, copper), as are the decades of installation.[17] 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. The O&M data are separated into various components, such as distribution, transmission, etc. Separately, SNL also provides information on all rate cases that investor-owned utilities face.

[16] We drop utilities that appear in this dataset but report zero residential customers, in order to focus our sample on distribution utilities.

[17] Materials data are available for our entire time period, but age data begin only in 2004. Moreover, 8% of miles are reported as "unknown decade." As a result, we focus on materials rather than age for most of our analysis.

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 assemble from several sources a list of alternative rate case proceeding regulations, which we discuss below.

We use the annual state-level citygate price, in \$/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 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, since it is typically not reported to state public utilities commissions. 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 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 the end-user purchases by companies with residential customers.

We next provide a detailed understanding of leak data. For years, the EIA has collected data on natural gas that can be used to infer leaks. Industry reports have criticized the use of these data,[18] 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,

[18] See, e.g. the American Gas Association's webpage "Unaccounted for Natural Gas in the Utility System" at https://www.aga.org/content/unaccounted-natural-gas-utility-system.

Table 1: Summary Statistics

	Full			With Financial Data		
	Mean	Std. Dev.	N	Mean	Std. Dev.	N
Volume leaked, Bcf	0.18	2.06	22,580	1.05	4.54	2,958
Volume leaked, %	1.70	3.70	22,580	1.05	2.64	2,958
Volume purchased, Bcf	15.38	78.55	25,096	81.53	154.48	3,051
Total end-user customers, count	49,911.06	247,108.15	25,096	332,859.29	611,704.18	3,051
Pipeline mains, miles	882.21	3,355.34	21,173	5,222.39	7,326.45	2,756
Unprotected bare steel	44.97	294.45	21,174	307.53	733.11	2,756
Unprotected coated steel	16.11	178.52	21,174	108.78	469.93	2,756
Cathodically protected bare steel	10.80	161.69	21,174	49.79	185.43	2,756
Cathodically protected coated steel	365.96	1,685.59	21,174	2,173.17	3,493.70	2,756
Plastic	408.15	1,532.65	21,174	2,344.70	3,421.92	2,756
Cast iron	32.93	223.10	21,174	220.10	570.61	2,756
Other	3.24	126.85	21,173	18.30	347.17	2,756
Low-quality mains, %	4.21	11.69	21,094	10.61	14.34	2,756
Average pipeline age, years	26.18	13.46	10,575	26.85	10.28	1,690
City-gate price, $/Mcf	6.75	2.31	29,583	7.14	2.36	3,089
O&M expenses, $000				23,596.38	38,091.57	3,001
Capital expenses, $000				34,254.94	54,082.89	2,477

Notes: The full sample is a census of 1,557 natural gas distribution utilities. The financial reporters sample is composed of 240 large investor-owned utilities, representing 75% of total purchases by companies with residential customers. 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. Prices and expenses are listed in 2015 dollars.

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.[19] In the industry, this is known as lost and unaccounted for gas or LAUF.[20] Unfortunately, the LAUF variable cannot be broken down into leaks from the distribution network versus, e.g., transmission or storage. In general, we interpret our results as driven primarily by the distribution network, for several reasons. First, the companies in our dataset are primarily engaged in the distribution business rather than the transmission or storage business, as we demonstrate in the Appendix. Second, we rely on an identification strategy that leverages changes in distribution-related incentives (described below). Finally, in the Appendix we

[19]The EIA-176 form has also, since 2002, asked utilities to report the volume in 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.

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

examine the impact on our results of weighting by the portion of each utility's purchases that are from the citygate (as opposed to an interstate pipeline or storage facility), and we find that our conclusions are robust.

However, our leaks variable, defined as the difference between purchases and sales, is imperfect in other ways. 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 (7 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 drop outliers (the upper and lower 5% of leak rates).[21]

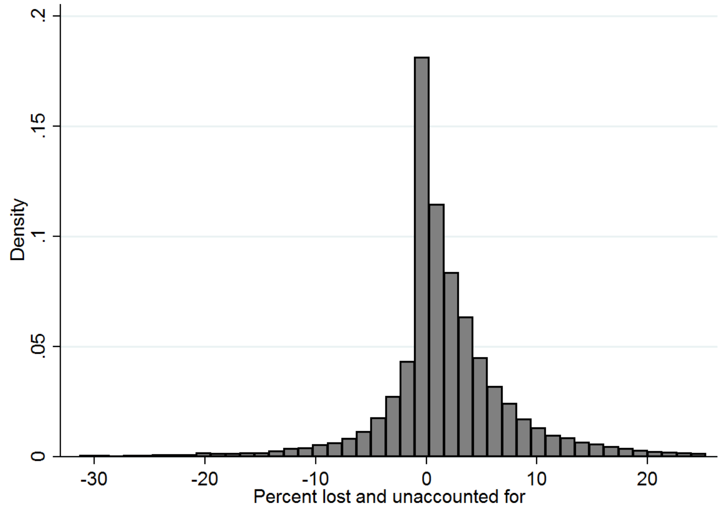
There are several reasons that the LAUF variable may not correspond exactly to leaks to the atmosphere, some of which also explain the noise. For volume measurements to be consistent, a gas must be at a standard temperature and pressure. Respondents to the EIA-176 survey are instructed to correct all 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, the amount of gas stored in the pipeline itself can vary over time. Similarly, 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).[22] There are also errors from meter inaccuracies and accounting mistakes.[23] 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).

[21] Our results are robust to trimming only the upper and lower 1% (Appendix Table A4).

[22] 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.

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

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.

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. While some variables are available beginning in 1995, pipeline age data were only collected beginning in 2004. (In addition, some variable definitions were changed by PHMSA in 2004, so for the rest of the paper, we use 2004-2013 as our primary sample.)

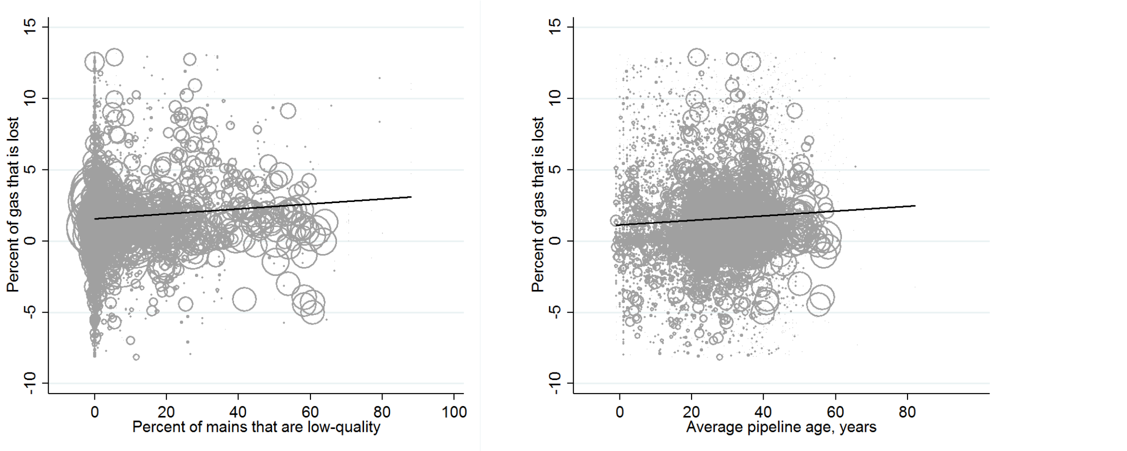
Observations in Figure 2 are sized according to the total volume of gas sold. The black line shows a regression line fit through the observations. While there is a great deal of noise in the leaks variable, there does appear to be a positive relationship between leak rates and low-quality pipes. It is 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 A1).

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. When weighting by firm size, the distribution is even narrower. 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 over 40 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. This provides reassurance that measurement error will be less of an issue for the firms on which we focus our analysis. Nonetheless, we will rely on empirical strategies 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 replacement. 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 repair-

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.

ing 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 (Table A9). Overall, they span a range of costs – from so negligible the EPA does not report a cost, up to over $7 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, rather than simply the range of *potential* activities. 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 the commodity cost (citygate price). Binding safety or environmental regulations would incentivize utilities to abate at greater cost. In practice, as described above, utilities likely internalize some safety concerns but not greenhouse gas costs. In light of the reimbursement rules, we aim to test whether they fully internalize commodity costs.

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. Ideally, we would estimate a cost function of the form

$$E_{it} = \beta_0 + \alpha A_{it} + X_{it}\Theta + \varepsilon_{it}, \tag{1}$$

where E_{it} is expenditures, A_{it} is the amount of gas abated in Mcf, and X_{it} is other determinants of expenditures. Unfortunately, we do not directly observe A_{it}. Instead, we can only observe L_{it}, the amount of gas leaked, where $A_{it} = L^c_{it} - L_{it}$ and L^c_{it} is the unobservable counterfactual leakage absent abatement activities.

As such, one feasible approach is to regress expenditure amounts on volumes leaked:[24]

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

This regression would capture that reducing leaked gas requires abatement expenditures. However, not all of the observed reduction in leaks is necessarily from abatement; we don't know what the counterfactual amount of leaked gas would be in the absence of abatement.

[24]Below and in the Appendix, we also consider the reverse specification, in which volumes leaked are regressed on expenditure amounts, and the coefficient on expenditures gives the inverse of the abatement cost. Both forward and reverse estimation require an instrumental variables approach, since both leak volumes and expenditures have measurement error.

Therefore, using data on gas leaked can be thought of as having measurement error around A_{it} where L^c_{it} is the measurement error. It would be classical if L^c_{it} were uncorrelated with A_{it}, although in practice that may not hold. For a constant L^c_{it}, equation (2) could be estimated in place of equation (1), with $\alpha = -\beta_1$. In practice, L^c_{it} is not expected to be constant, and so we consider an instrumental variables approach.

To solve both the measurement error related to unobserved counterfactual leaks and the measurement error related to the LAUF variable described in the data section, we require an instrument that incentivizes leak detection and repair, impacting expenditures only through these abatement activities. For our instrument, we leverage increasingly stringent distribution-related safety regulations since 2010 (details on the variable's construction follow). Intuitively, these regulations should have incentivized utilities to conduct additional repair activities, raising expenditures and reducing leak volumes.[25] Moreover, they should not impact counterfactual emissions L^c_{it}. The use of our instrument has an additional benefit: by focusing on distribution-related incentives, it will alleviate bias related to activities at other (non-distribution) parts of the supply chain. Our estimating equation then is:

$$E_{it} = \beta_0 + \beta_1 \widehat{L_{it}} + X_{it}\Theta + \varepsilon_{it}. \tag{3}$$

Here E_{it} is distribution operations and maintenance expenditures in 2013 dollars and L_{it} is the volume of leaked gas in Mcf.[26] We scale expenditures and leaked gas volumes, as well as the controls listed below, by the average number of pipeline miles for each utility over our

[25]Repair activities themselves may involve risk, in which case the social cost/benefit analysis of leak repairs should take into account the difference in risk between repairing and not repairing. For our estimates of O&M costs and comparison to commodity value, we are implicitly assuming that neither safety risks from leaks nor risks from repairing leaks are internalized by the firm. While it is possible that some risk is internalized (for instance, via lawsuits), estimates of safety risks in the Appendix are small enough that this issue appears negligible.

[26]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.

sample period, $\frac{1}{T}\sum_{t=2004}^{2013} miles_{it}$. As Table 1 shows, utilities vary tremendously in size, so the literature has found scaling helpful for precision and to reduce the influence of outliers (Davis and Muehlegger, 2010). Here $-\beta_1$ is the coefficient of interest: the cost of abatement that utilities have undertaken, in \$/Mcf. Because both the left-hand and right-hand side variables are scaled by the same amount, this interpretation is unaffected by scaling. (In the Appendix, Table A4, we show that results are similar when we do not scale.)

The controls X_{it} include Census region-by-year effects, utility effects, as well as a number of utility-specific, time-varying variables. We control for total volume sold, total miles of mains (time-varying, in contrast to the scaling variable), 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. In the next section, we directly estimate the cost of pipeline replacement, but here we wish to control for it to isolate other leak mitigation activities. We note that in the Appendix we also estimate versions of equation (3) that take capital expenditures into consideration (Table A4). The Appendix also shows that results are robust to alternative sets of controls. We winsorize the upper and lower 1 percent of outliers (but the Appendix shows that results are robust to dropping and to neither dropping nor winsorizing). Standard errors are clustered at the utility level.

The basis of our instrument is as follows. As described in Section 1.2, stricter safety regulations issued by PHMSA took effect in 2010.[27] These required "integrity management" plans from distribution companies. Each company was required to take an assessment of its own risks, informed by specific characteristics of its distribution network, to have risk mitigation plans, and to maintain ongoing records.[28] Progress was intended to be mea-

[27]The stated goals of the regulation were generally related to safety, rather than to recovery of lost gas per se, but ex-ante impact analysis assumed that lost gas would be reduced in practice.

[28]Specific actions were not generally mandated by the law. However, examples of specific processes mentioned in PHMSA supporting documentation or in individual company compliance plans include, but are not limited to: leak surveys with detection equipment; expanded operator qualification programs; installation of excess flow valves; inspections at bridge crossings; increasing information provision to the public on

sured against the utility's own historical baseline, rather than against national averages, in recognition of the heterogeneous risks faced by each utility (depending on materials used historically, climate and seismic conditions, etc.).

Our instrument is the utility-specific historical leak volume interacted with a dummy for the years following the implementation of more stringent PHMSA safety regulations.[29] The idea is that the PHMSA rules incentivized all utilities to upgrade their pipes, but these regulations were more binding for utilities with historically bad system leaks. The utility fixed effects control for the level effect of having a historically leaky network, so the IV is capturing only the differential effect following the implementation of PHMSA regulations.

We construct the instrument by multiplying a dummy for the years after the PHMSA regulations were enacted (2010 and beyond) by the leaks reported by each utility in the years leading up to the PHMSA regulations, in particular the average annual leak volume in the years 2004 to 2009. Thus we expect to see in the first stage that higher pre-regulation leak volumes lead to greater reductions in leak volumes after the regulations are enacted. As with the other variables, we scale by each utility's average number of pipeline miles over the sample period. In the Appendix, we examine specifications designed to address various potential concerns arising from the use of this instrument, finding that our results our robust.

The instrument gives first-stage results with reasonable power and with expected signs, as shown in Table 2. The historical leak volume interacted with post-PHMSA regulations has a negative and statistically significant coefficient, implying that utilities with leaky networks were differentially incentivized by the regulations to reduce leak volumes. The magnitude of the coefficient, -0.43, implies that for every additional 1 Mcf of gas leaked per mile in the pre-regulation period (relative to the average utility), the utility abated an additional 0.43 Mcf per mile in the post-regulation period. The Kleibergen-Paap first-stage F-statistic

excavation risk; installation of liners in pipes; and pipeline replacement.

[29] We note that 2010 was also the year of the San Bruno accident in California, mentioned above. This led to greater scrutiny on the responsible company, Pacific Gas & Electric (PG&E), including on non-distribution components of its extensive supply chain. We drop PG&E from our sample, because the San Bruno effect cannot be disentangled from the PHMSA effect given our lack of detailed transmission data.

Table 2: Instrumenting for Volume Leaked: First Stage

	(1) Volume Leaked
Excluded Instrumental Variables:	
Past volume leaked×I(Post-PHMSA)	-0.43***
	(0.10)
Controls:	
Volume sold, Mcf	-0.01**
	(0.00)
Pipeline mains, miles	83.23
	(89.37)
Service lines, count	-0.94
	(1.31)
Low-quality mains, miles	-901.91**
	(383.55)
Low-quality service lines, count	-0.14
	(2.66)
Region-year effects	Yes
Utility effects	Yes
Observations	1,551
R^2	0.63
Kleibergen-Paap F-stat.	17.96

Notes: Dependent variable is the endogenous regressor in Table 3: volume of leaked gas in Mcf. The instrument is the utility's average volume of leaked gas in the period before PHMSA increased regulations, interacted with a dummy for the period after PHMSA increased regulations. All variables are scaled by the utility's average count of pipeline miles over the sample period. Standard errors are clustered by utility. *** Statistically significant at the 1% level; ** 5% level; * 10% level.

(which is robust to non-i.i.d. errors) is 17.96, which is above the Stock and Yogo (2005) critical value of 16.38 (for 10% maximum relative bias). We also reject the null that the equation is underidentified, with a p-value of 0.0027.

Table 3 shows the OLS and 2SLS results for the main coefficient of interest, which is on the volume of natural gas leaked – this coefficient is the cost of abatement utilities have undertaken, in $/Mcf. The coefficient on volume leaked is expected to be less than zero in both columns: it gives the increase in expenditures associated with a reduction in volume 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 estimate of abatement expenditure is small: $0.13/Mcf. Given the endogeneity concerns discussed above, the second column is more informative. In Column (2), using the instrument described above, we estimate a cost of abatement of around $0.48/Mcf. The final row of the table tests the abatement cost estimate against the

Table 3: Abatement Costs: Operations and Maintenance Expenditures

	OLS	IV
	(1)	(2)
	O&M	O&M
Volume leaked, Mcf	-0.13	-0.48
	(0.08)	(0.92)
Volume sold, Mcf	0.02	0.02
	(0.03)	(0.03)
Pipeline mains, miles	1,161.05	1,130.18
	(804.09)	(764.79)
Service lines, count	9.04	8.86
	(13.45)	(12.38)
Low-quality mains, miles	-2,378.39	-2,621.54
	(4,159.24)	(4,048.68)
Low-quality service lines, count	-29.55	-28.42
	(25.28)	(23.88)
Region-year effects	Yes	Yes
Utility effects	Yes	Yes
Observations	1,579	1,551
R^2	0.97	.
Kleibergen-Paap F-stat.	.	17.96
Difference from citygate price ($/Mcf)	5.54***	5.19***

Notes: Dependent variable is the utility's expenditures on O&M. The coefficient on "Volume leaked, Mcf" represents the amount spent on distribution O&M to reduce natural gas leaks, in $ per Mcf. The average citygate price, post-2010, in our sample is $5.67. Column (2) instruments for the volume of leaks abated using the utility's average volume of leaked gas in the period before PHMSA increased regulations, interacted with a dummy for the period after PHMSA increased regulations. All variables are scaled by the utility's average count of pipeline miles over the sample period. Standard errors are clustered by utility. *** Statistically significant at the 1% level; ** 5% level; * 10% level.

average commodity value for the period of increased regulatory stringency: citygate prices average \$5.67/Mcf in our sample for 2010-2013. We find that the 2SLS estimate of \$0.48/Mcf is statistically different from the citygate price at the 1 percent level.

It is striking that the safety-related instrument leads to a cost of abatement that is below the average commodity value over the period of increased regulatory stringency. Most importantly, 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 commodity value. In addition, the coefficients in Table 3 are equal to the marginal cost of abatement only if the abatement persists just one year. It is possible that the abatement activities persist beyond one year, which would mean abatement expenditures are even lower than the reported coefficients. EPA documentation of suggested repairs (Table A9) frequently assumes an equipment lifetime beyond one year. Moreover, additional cost savings mentioned after the first year include, for instance, leveraging knowledge from the first year to be able to focus in future years on components most likely to leak. Unfortunately, it is difficult to verify this empirically, because estimation with lags requires multiple endogenous variables and multiple instruments, and we have low power.

To summarize, we use an instrumental variables approach to estimate the cost of O&M-intensive leak abatement. Our preferred specification gives a point estimate of \$0.48/Mcf. This indicates that there was low-hanging fruit in terms of leak mitigation opportunities that utilities were not fully incentivized historically to find. This is consistent with reimbursement of leaked gas costs.

In the Appendix, we show that the results are robust to alternative controls,[30] alterna-

[30] We show results with year effects rather than region-by-year effects; regional cubic time trends rather than region-by-year effects; results that control only for region-by-year effects and not for, e.g. pipeline miles; results controlling for a cubic function of volume sold and for retail prices; results controlling for differential linear trends for utilities that had historically high leak rates; and results controlling for utility-specific time trends. The differential time trends are intended to use only variation induced by the 2010 regulations, rather than a general trend of improvements to historically leaky networks.

tive sub-samples,[31] weighting,[32] and alternative variable definitions.[33] We also show results including capital expenditures in the dependent variable. We maintain first stage power, and the resulting abatement cost estimates are comparable for all these alternative specifications.

We also estimate specifications using alternative instrument definitions, to leverage alternative sources of identifying variation. As shown in the Appendix, we first use the leak rate, rather than the leak volume. We next define the instrument using leaks in 2004, before the regulations would have been anticipated by the utilities. We next define the instrument using many more years of data (1995-2009). Finally, we use first-differences variation only, i.e. the nation-wide impact of the 2010 regulations, by defining our instrument as a dummy equal to one for all years beginning in 2010 for all utilities. In this latter specification, we control for regional cubic trends, rather than for region-by-year effects. We include these latter two specifications because of potential concerns about mean reversion driving the main results. Our primary specification uses an instrument constructed off of six years of leak volumes, so we do not expect mean reversion to be a significant issue. Nevertheless, the specification using more years of data is reassuring for alleviating any concerns along this line, as is the first-difference specification (since it uses only time-series variation). Again we find that our main results are robust to these alternative specifications.

Additionally, we show reverse-OLS and reverse-2SLS specifications in the Appendix. We have focused on the specification in which expenditures are regressed on leak volumes, since the resulting coefficient gives the parameter of interest directly. However, one could also estimate the reverse specification. The OLS specification is problematic since expenditures contain measurement error – in particular, we observe *all* O&M expenditures, rather than expenditures specifically aimed at leak mitigation efforts. As such, we expect the 2SLS specification to again be more informative. As the Appendix shows, estimating this reverse-

[31]We present results using bundled utilities only (i.e., not delivery-only utilities); and dropping all of California rather than simply PG&E

[32]We present results weighting each firm by the portion of its purchases coming directly from the citygate.

[33]For alternative variable definitions, we trim leaks at the one percent rather than five percent tails; drop rather than winsorize outliers; keep outliers as is; and do not scale variables.

2SLS specification and using the inverse of β_1 as our parameter of interest is identical to the strategy we have followed in our main specification (they are in fact mathematically equivalent), since the 2SLS coefficient in the case of one instrument is simply equal to the ratio of the first stage and reduced-form coefficients.

To interpret our findings, we note that our estimate is consistent with the range of cost estimates for leak detection and repair that are published by the EPA's Natural Gas STAR program. We also note that our estimate is below the commodity cost of gas itself which utilities save when they repair leaks. Moreover, the estimate is a local average treatment effect (LATE) driven by safety regulations, which would be expected to incentivize utilities to abate above and beyond the commodity value of leaked gas. There are two possible interpretations of this result. One possibility is that utilities "walk up the abatement cost curve," and that prior to the safety regulations, they were undertaking only abatement activities costing less than our \$0.48/Mcf estimate. In this case, the increased safety regulations moved utilities closer to the socially optimal outcome, although not fully to the point where marginal benefit equals marginal cost. An alternative possibility is that utilities select some suite of abatement actions, not necessarily undertaking the cheapest activities first. That is, we cannot rule out that safety-related repairs were conducted at a high cost even in the years prior to the increased regulation. But in this case, the \$0.48/Mcf estimate implies that, regardless of what abatement they undertook before safety regulations were tightened, there was low-hanging fruit in the form of inexpensive abatement actions that they undertook once the regulations became more binding.

Overall, the cost estimates are consistent with a setting where utilities are reimbursed for lost gas in the rates they charge customers. Moreover, despite increased safety regulations in recent years, there appear to have been activities available costing 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.[34]

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. Pipelines must eventually be replaced, and this replacement rate might be determined by engineering analyses of time-to-failure. Our calculations allow us to ask the question, "does pulling forward the replacement timeline in order to obtain greenhouse gas abatement pass a cost/benefit test?"

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

$$E_{it} = \beta_0 + \beta_1 P_{it} + X_{it}\Theta + \varepsilon_{it}. \tag{4}$$

Our dependent variable of interest E_{it} will again be expenditures, but now we focus on distribution-related 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

[34]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.

out-of-date records at PG&E, the utility responsible for the San Bruno explosion. 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 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.[35] 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.[36]

To deal with the first set of endogeneity concerns (e.g. classical measurement error), we again use an instrument related to safety regulations. This instrument 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

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

[36] 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 categories of distribution 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.

estimate is thus:

$$\Delta E_i = \beta_0 + \beta_1 \widehat{\Delta P_i} + X_i \Theta + \varepsilon_i. \tag{5}$$

Here ΔE_i is new capital accumulated by the plant, calculated as the sum of new capital expenditures over the period 2004 to 2013. ΔP_i is the reduction in low-quality pipeline miles from 2004 to 2013, instrumented with historic pipeline quality. As in the previous section, we scale all variables by the utility's size. 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 sold, 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 A6); the coefficient on the instrument has the expected sign and is statistically significant at the one percent level. The Kleibergen-Paap F-statistic is 40, i.e. above the Stock and Yogo (2005) critical value of 16.38.

Table 4 gives OLS and 2SLS estimates. After instrumenting for pipe replacement, the point estimate is 1,222 (in $000), implying that the replacement of one bad pipeline mile costs $1.2 million dollars. The OLS estimate is smaller, with one mile costing $607 thousand 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

Table 4: Cost of Pipeline Replacement

	Total Capital Expenditures, 2004-2013 ($000)	
	(1)	(2)
	OLS	IV
Low-quality main replacement, miles	607.17**	1,221.89**
	(257.49)	(506.55)
Δ volume sold, Bcf	-505.98	-1,016.83
	(4,119.03)	(3,638.49)
Δ mains, miles	147.89**	194.49***
	(61.68)	(59.29)
Δ customers	2.71	2.77*
	(1.65)	(1.57)
Region effects	Yes	Yes
Observations	140	140
R^2	0.38	.
Kleibergen-Paap F-stat.	.	40.02

Notes: Dependent variable is the sum of capital expenditures made from 2004 to 2013. In column (2) the reduction in low quality mains from 2004 to 2013 is instrumented for using the miles of low quality mains in 2004. First stage results are found in Table A6. All variables are scaled by the utility's average count of pipeline miles over the sample period. Robust standard errors in parentheses. *** Statistically significant at the 1% level; ** 5% level; * 10% level.

streets, is likely more expensive than replacing pipe in a more rural area.[37] Moreover, large 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:

$$L_{it} = \beta_0 + \beta_1 P_{i,t-1} + X_{it}\Theta + \varepsilon_{it} \tag{6}$$

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 (all scaled by utility size, as in the previous sections). 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

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

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.[38]

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 lagged miles of medium-quality miles, lagged volume sold, the lagged number of total miles, and region-by-year effects. The lagged sales variable aids with both precision (by absorbing a determinant of leaks) and with identification (since it could be correlated with service territory changes). The lagged total pipeline miles variable again controls 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. All variables are scaled by the utility's average length of pipeline miles over the sample period. Region-by-year effects control for differential trends in leak rates across regions coming from, for instance, differential weather trends. Much of the identifying variation is cross-sectional, since pipeline upgrades are slow (including utility effects leads to quite noisy estimates). We estimate that 573 Mcf are abated per mile of low-quality main replacement (Appendix, Table A8).

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

[38]Note that in the O&M cost estimation, our abatement costs are measured per *realized* Mcf abated, that is, net of any venting that occurs during repairs. This is precisely the parameter of interest. In contrast, for emissions factors, we are interested in abatement realized over the lifetime of the pipe. Since venting would occur only in the first year, we focus on the emissions factor for each year thereafter. In principle, one would want to estimate the abatement in the first year (net of venting) and abatement in subsequent years (in which venting does not occur), then use these two separate emissions factors in the levelized cost calculation. Unfortunately, we do not have the power to do that. To the extent that realized abatement is lower in the first year, this would imply that our levelized costs would be too small, although this effect is likely negligible.

in historical changes in pipes, and utilities presumably targeted the leakiest pipes first. Accordingly, the estimated 573 Mcf/mile is as an upper bound on the average emissions factor. We also correct the emissions factor for the 18 percent oxidation rate described in Section 2, and thus use 470 Mcf/mile as an upper bound to the emissions factor.[39] Finally, to the extent that utilities with old pipelines also have old surface facilities, this will bias our emissions factors upwards, again indicating that the 470 emissions factor is an upper bound. In contrast, the EPA uses an estimate of 229 Mcf per mile of cast iron relative to plastic pipe.[40] 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.[41] 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 A1. We note that transforming these coefficients at median sample values for the financial reporters gives an emissions factor between the EPA's rate and our 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

[39]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 5. This would not change the conclusions we present below.

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

[41]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.

costs, e.g. Borenstein (2012). The equation we use is:

$$LC = \frac{\sum_{t=0}^{T}\left(\frac{E_t}{(1+r)^t}\right)}{\sum_{t=0}^{T}\left(\frac{Mcf_t}{(1+r)^t}\right)} \tag{7}$$

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 main calculation uses the estimated $1.2 million pipeline replacement capital cost; an alternative calculation uses $607,000, matching both our OLS estimate and some of the lower-end estimates reported in public sources (see Table A10). 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: 470 Mcf/mile and 229 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 60 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 5 shows the resulting levelized cost calculations. With our preferred set of parameters, we calculate a levelized cost of natural gas leak abatement of $103/Mcf from pipeline replacement programs. This cost varies from $48 to $211 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 more than an order of magnitude larger. As such, we

Table 5: Levelized Cost of Abatement via Pipeline Replacement

	(1)	(2)	(3)	(4)	(5)	(6)
Capital cost, $	1,221,890	607,170	1,221,890	1,221,890	1,221,890	1,221,890
Abatement rate, Mcf/mile replaced	470	470	229	470	470	470
Discount rate	0.03	0.03	0.03	0.07	0.03	0.03
Lifetime	40	40	40	40	60	40
Offset O&M, $ per year	-3,049	-3,049	-3,049	-3,049	-3,049	0
Levelized cost, $/Mcf	103	48	211	176	85	109

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.

can conclude that pulling forward the pipeline replacement timeline has not historically been a cost-effective method (on average) of capturing lost commodity, nor of averting greenhouse gas consequences. This finding is consistent with an Averch-Johnson effect, in which utilities might be more willing to engage in capital investment than in O&M expenditures, because the former earns them a rate of return while the latter does not. However, an Averch-Johnson effect is not the only potential explanation. It is also possible that utilities have concentrated more on pipeline replacement programs because of perceived safety benefits, or that public utility commissions have been more willing to approve pipeline replacement programs because of perceived safety benefits. Leak detection repair programs and pipeline replacement programs are not necessarily substitutes for one another in terms of averting explosions. It is not only the quantity of gas that is leaked that poses a risk for explosion, but also how much of the gas can accumulate, and how close the leak is to a population center. Thus a citygate station that is leaking to the atmosphere would pose less of an explosion risk than a pipeline that is leaking into an enclosed space. Moreover, the citygate station is likely to be further from population than a leaking pipeline; the latter would present a greater safety threat if it is in a densely populated urban area.

In general, then, it does not necessarily follow that utilities are engaging in too much pipeline replacement, from a social planner's perspective. First, safety benefits must be accounted for, and are likely not perfectly correlated with other leak abatement benefits. In addition, as Column (2) demonstrates, the levelized cost of pipeline replacement is much closer to the benefit of replacement in areas where capital costs are lower than average.

To better understand the impact of safety benefits, we collect PHMSA data on fatalities, injuries, and property damages. With these data, we estimate the safety benefits of reducing leaks and of replacing low-quality miles.[42] We use a panel 2SLS approach, with the same instrument 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 A11. 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.[43] 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 $0.19/Mcf. The additional safety benefits associated with pipeline replacement are in the range of $0-600 per mile per year, or up to $2.65/Mcf (depending on the emissions factor used). The combined benefits (recognizing that pipeline replacement entails leak reductions) are estimated to be at most $2.74/Mcf. This translates into a net present value that is substantially less than the replacement costs estimated in Table 4. 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, using the emissions factors presented above, it appears that the safety benefits of pipeline upgrades may be larger, in $/Mcf terms, than

[42]Because some of these accidents might have arisen during repairs themselves, the estimates are interpreted as the risk reduction net of any risks from repairs. As such, this estimate is useful in order to compare with actual expenditures, because this estimate accounts for any of the net risk that the firm undertakes in order to do the repair.

[43]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.

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 a cost-effective way of addressing greenhouse gas externalities, but that they may 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. This regression is thus nearly identical to the reduced-form regression estimated as part of the 2SLS results provided in Table 3, but with additional explanatory variables included and with both distribution and capital expenditures on the left-hand side. We did not include these explanatory variables in our previous analysis because their causal interpretation is less clear. However, as we demonstrate in the Appendix, including these additional control variables does not significantly change the coefficients of interest in the reduced-form results underlying Table 3.

We again control for total pipeline miles and total volume of gas sold to absorb variation that could impact expenditures and could also be correlated with the explanatory variables (for instance, expansion of service territory). Also, we again scale variables by the utilities' size. 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 new 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 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 6 shows, utilities spend *less* (although not significantly different from zero) in the short-run on maintenance and capital when citygate prices are high. The magnitude of the effect is small; a $1 increase in city gate price results in total expenditures falling by 2 percent. 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. We note that citygate prices fell approximately 40 percent from the period 2006-09 to 2010-13, so there should be sufficient variation to pick up any effect.

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 6 shows that these variables are associated with higher spending, both in terms of O&M expenditures and capital expenditures. The magnitudes are large; the coefficients imply that total expenditures are 13% higher during a rate case and 7% higher during a test year. There are two possible explanations, which cannot be separately identified in this regression

Table 6: Reduced-Form Estimates of What Explains Utility Expenditures

	Expenditures		
	(1) Total ($)	(2) O&M ($)	(3) Capital ($)
Past volume leaked×I(Post-PHMSA)	0.09	0.30	-0.11
	(1.87)	(0.39)	(1.62)
<u>Other economic and regulatory variables:</u>			
City-gate price, $/Mcf	-194	-46	-115
	(342)	(48)	(287)
Fraction of year in a rate case	1473**	307**	1070*
	(653)	(151)	(576)
Fraction of year in a rate-case test year	823*	179***	598
	(475)	(59)	(420)
I(Utility has pipeline rider)	1993**	-35	1868**
	(927)	(160)	(822)
<u>Controls:</u>			
Pipeline mains, miles	20020**	836	14754***
	(7852)	(757)	(5503)
Service lines, count	-10.58	3.76	-17.15
	(55.96)	(11.48)	(39.74)
Volume sold, Mcf	-0.02	0.03	-0.06
	(0.17)	(0.03)	(0.15)
Region-year effects	Yes	Yes	Yes
Utility effects	Yes	Yes	Yes
Observations	1,490	1,603	1,490
R^2	0.84	0.97	0.77
Mean of dependent variable	11,736	4,550	7,076

Notes: Dependent variables by column are: (1) the sum total of capital and O&M expenditures; (2) O&M expenditures; and (3) capital expenditures. All variables are scaled by the utility's average count of pipeline miles over the sample period, except price, fractions, and indicator variables. *** Statistically significant at the 1% level; ** 5% level; * 10% level.

framework, because rate-case timing 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.[44] We estimate that total expenditures are 17% higher when such a mechanism is implemented, 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 a variable designed to capture regulatory stringency related to safety. We use the same instrument used in Section 3.1, the interaction of the post-PHMSA regulation dummy with the pre-regulation leak volume. Again, this interaction captures the differential effect for the utilities with worse networks, in the years when following the new PHMSA regulations. We find higher spending on maintenance, consistent with the results in Section 3.1, although the standard errors are too large to be conclusive. This is consistent with utilities responding to safety regulations by increasing expenditures for abatement

[44]We checked three sources for company names and locations and implementation dates: Yardley Associates (2012), American Gas Association (2012), and the "Natural Gas State Profiles" section of the current American Gas Association website (https://www.aga.org/knowledgecenter/facts-and-data/state-profiles-natural-gas), accessed August 15, 2016. The three sources had a high degree of overlap.

projects, but also consistent with the low abatement costs estimated above.

In summary, we see that variables associated with economic regulations (such as the rate case variables and the pipeline rider variable) are associated with O&M expenditures and capital expenditures. In contrast, the coefficient on the citygate price has an unexpected sign. 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 regulatory incentives.

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 gas, losses continue to occur throughout the supply chain. Focusing on the distribution network, we find that leak abatement incentives are misaligned because of the form of price regulations that utilities 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. Increasingly stringent safety regulations have, however, led to increased utility expenditures and decreased leak rates. 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 $0.48 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. While consistent with an Averch-Johnson effect, it is also consistent with differential perceptions of safety benefits. The results do not necessarily imply that pulling forward some pipeline replacement programs in order to obtain GHG abatement would not pass a cost/benefit test. For some parameter combinations, levelized costs close to the societal benefits described above are possible.

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. Regulations that would allow for cost-recovery without distorting abatement incentives could be designed based on the incentive regulations used in the electric utility industry, for instance. Rather than simply ending reimbursement, one could imagine allowing reimbursement for the national average leak rate rather than for a utility's own rate (and thus preserving marginal abatement incentives).[45] A complication, though, is that 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, and as we cite above, regulators have been reluctant to use it. While the measure is useful for our analysis once we use an empirical strategy that is robust to 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.[46]

Of course, 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

[45] Or, given heterogeneity in existing infrastructure, the benchmark could be for a peer group of utilities rather than the national average.

[46] 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.

environmental regulations. In a similar spirit to the incentive-compatible reimbursement policy described above, an incentive-compatible climate policy could be designed. The regulator could tax utilities for the climate costs of their own leakage, but allow them to pass on costs to their customers at the national average leak rate. This would again preserve marginal incentives while allowing for profit neutrality on average.

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 venting and 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.

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Appendix

In this Appendix, we provide additional tables and figures referred to in the main text.

Figure A1 compares the density of leak volumes as a percentage of total volume purchased for the full sample of utilities (grey) versus just those utilities reporting financial information (green). It additionally shows the impact of weighting by firm size (red). 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 – and is even lower when weighting by firm size.

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 2. Here, we formalize the relationship with regressions (Table A1). 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.[47] 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 0.26. 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.

[47]As mentioned, 8% 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.

These results are robust to additional specifications, as shown in Columns (2) - (5). 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. 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. Several tables provide alternative specifications for the regressions in Table 3, which estimate the cost of leak abatement. Across more than twenty alternative specifications, we obtain results very similar to our main specification.

Table A2 shows alternative forms of the IV. Here we aim to leverage alternative sources of identifying variation. In Column (1) we use the leak rate (not scaled by pipeline miles), rather than the leak volume. In Column (2) we use leak rates from 2004 only – i.e. before the regulations could have been anticipated by utilities. Column (3) defines the instrument using a longer sample (1995-2009). As such, the regression uses the full sample (1995-2013) of data, whereas the main specification is limited to 2004-2013. This specification is intended to alleviate concerns about mean reversion in the leaks variable. Column (4) uses first-differences variation only, i.e. the nation-wide impact of the 2010 regulations, by defining our instrument as a dummy equal to one for all years beginning in 2010 for all utilities. In this latter specification, we control for regional cubic trends, rather than for region-by-year effects. While we do not expect mean reversion to be a problem given that our instrument is defined off of six years of leak volumes, this first-difference specification alleviates any potential concerns along this line. Finally, Column (5) uses two instruments, the indicator for the period after PHMSA increased stringency as well as the main instrument (past leak volumes interacted with the indicator of post-PHMSA regulations). Across all five columns we have estimates similar to our main estimate.

Next, Table A3 shows the reverse-2SLS estimation in which we regress leak volumes on expenditures and use the same instrument as our main specification. For these specifications, the coefficient on expenditures gives the inverse of the abatement cost. We prefer forward-2SLS since the coefficient gives the parameter of interest directly, but we show the inverse specifications for completeness. Reverse-OLS is expected to perform poorly, since the right-hand side variable of interest (expenditures) has measurement error. In particular, it includes spending on things other than leak repairs. As such, we expect the 2SLS specification to again be more informative. As such, we estimate this reverse-2SLS specification and calculate the inverse of the coefficient on volume leaked. As expected, the resulting estimate is identical to the coefficient in our main specification (they are in fact mathematically equivalent), since the 2SLS coefficient in the case of one instrument is simply equal to the ratio of the first stage and reduced-form coefficients.

Table A4 shows alternative controls, alternative sub-samples, and alternative variable definitions. Column (1) uses year effects rather than region-by-year effects. Column (2) includes an indicator for post-PHMSA regulations as well as a cubic of regional time trends instead region-by-year effects. Column (3) does not include any control variables, except for region-by-year and utility effects. Column (4) controls for a cubic of sales as well as a linear function of the retail price.

Columns (5) and (6) are designed to alleviate concerns that the instrument is simply capturing general trends in leak abatement, rather than variation specific to the 2010 PHMSA regulations. In Column (5) we control for the pre-regulation total leaks, interacted with a linear time trend. In Column (6), we control for utility-specific linear time trends. Both of these specifications, designed to capture the possibility of differential trends leading up to the PHMSA regulations in 2010, yield results similar to the main estimates.

Columns (7) and (8) of Table A4 use alternative sub-samples. Column (7) uses only a balanced panel of bundled utilities. Column (8) drops California rather than simply PG&E, because of changes in scrutiny in California following the San Bruno accident. Column (9) weights each firm by the portion of its purchases coming directly from the citygate, rather than from interstate pipelines, storage facilities, and other sources. Since we are unable to directly separate distribution-network and transmission-network leak volumes, this column is designed to more heavily weight those utilities with more transmission-related volumes. In our sample, the median utility reports that 85 percent of its purchases come directly from the citygate, and over 99 percent of its disposition is to end users. Given the low volumes coming from or going to transmission and storage networks (and given that our instrument is based off distribution-related regulations), we interpret our main specification as being driven primarily by distribution-related activities. It is nonetheless reassuring that the results in Column (9) are comparable to the main results.

Columns (10) through (15) of Table A4 use alternative variable definitions. Column (10) trims leaks at the one percent rather than five percent tails. Column (11) drops rather than winsorizes all outliers. Column (12) keeps outliers as is, rather than dropping or winsorizing them. Column (13) does not scale variables (the main specification scales by utility average pipeline miles).

Columns (14) and (15) examine the sensitivity of the results to including other expenses, such as transmission expenses and capital. In Column (14) we include capital expenses (after dividing expenses by 10 to approximate a 10-year levelization). In Column (15) we include many additional expenses. Since some of the leak volumes may have come from the transmission network, it is important to examine whether including transmission expenditures changes the results. For this specification, we aggregate the distribution O&M expenditures from the main specification with transmission O&M, storage O&M, customer information provision, sales and advertising, administrative expenses, and annuitized capital. It is reassuring that including these other expenditures does not change our conclusions about abatement costs. Lastly, Column (16) uses pre- and post-regulation averages rather than annual data; thus the identifying variation is for a longer time horizon. This robustness check alleviates concerns that there are unaccounted for dynamic effects, such as leak repairs lasting more than one year, or a utility's workforce taking time to adjust to new PHMSA regulations.

Overall, our results are robust across this broad array of robustness checks. Across all the columns in Table A4, we maintain first stage power, and the resulting abatement cost estimates are similar to the main result.

Table A5 replicates Table 3, 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. The columns mirror the specifications in Table 3; OLS and IV specifications are presented. We 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. However, this table is helpful to determine if there are tradeoffs between expenditure categories. If utilities face a soft budget constraint, we would expect to see large and significant abatement costs for categories such as "Maintenance: Mains" and "Maintenance: Services" (areas targeted by the programs described in Table A9) offset by estimates with the opposite sign for other categories. This is not the case, in that we don't generally see large positive and statistically significant results in any of the categories, providing evidence that the dependent variable used in Table 3 is appropriate. Three other specifications (not shown for space) aimed at understanding the possibility of a soft budget constraint are also reassuring. First, we run our main regression limiting the left-hand side expenditures to just the subcategories that on their own yield an estimate <0 in Table A5. This yields an estimated abatement cost of \$1.12/Mcf. Second, we limit the post-sample to 2013, giving utilities time to petition their PUCs for extra funds. The resulting estimate is again \$1.33/Mcf. Finally, we combined strategies (1) and (2), and the estimated abatement cost is again comparable. Overall, then, it does not appear that our conclusions are sensitive to the possibility of a soft budget constraint.

Table A6 provides the first stage results for the pipeline replacement regressions (the 2SLS results are shown in the text in Table 4). Having an additional mile of low-quality mains in the first year of the sample results in an additional 0.18 miles of pipeline replacement between the ten years.

Table A7 provides robustness checks for Table 4. Column (1) includes O&M as well as capital expenditures in the outcome variable. 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 (2) includes all gas-related capital, not just distribution-specific gas-related capital. Column (3) uses an alternative definition of capital: the change in accumulated capital, rather than the sum of capital additions. Column (4) does not include any control variables. In Column (5) we use data from 1998 to 2013, rather than 2004 to 2013 (accordingly, the instrument is defined using low-quality mains in 1998). Column (6) weights by portion of purchases made at the citygate (and not transmission or storage volumes). All columns scale all variables by utility's average pipeline miles across the sample period but Column (7) does not scale. Across these specifications, the cost of replacing low-quality pipe varies from $1.2 to 2.1 million per mile.

Table A8 provides results for the emissions factor estimation described in Section 3.2. Column (1) shows the full sample and Column (2) shows the subsample of utilities that report financial information. As the text details, these results provide an upper bound, so our analysis uses both the estimate given in Column (2) and an alternative estimate from the EPA as a lower bound.

Table A9 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 A10 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 A11 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. As we mention in the main text, some of these accidents might have arisen because of repairs themselves. As a result, the estimates are interpreted as the risk reduction net of any risks from repairs. This is precisely the parameter of interest for comparison with expenditures, because this estimate accounts for any of the net risk that the firm undertakes in order to do the repair.

The first column shows OLS results without fixed effects. This regression is arguably biased because those distribution companies with higher leak rates and poor-quality networks might for other reasons have more frequent and more costly accidents. We include this specification to get a sense of the upper bound on damages. We also provide the OLS estimates after including utility fixed effects (Column 2). Because of measurement error and the potential for unobservables to be correlated with the variables of interest, in the remaining column we instrument for both leaks and miles using two instruments. We interact past leak volumes and past count of low-quality miles with an indicator for the period after PHMSA regulations increased in stringency. The dependent variable for all three columns is the aggregate of property damages; fatalities using a Value of Statistical Life of \$9.1 million; and injuries, assuming \$1 million per reported injury. The implied leak abatement benefits in \$/Mcf is simply equal to the coefficient on "Volume leaked, mcf." The implied pipeline benefits rows re-scale the coefficient on "Low-quality mains, miles" by an emissions factor, in Mcf/miles, of either 229 or 470.

Overall, the safety benefits of leak abatement are noisy and estimated to be at most \$0.19/Mcf, although not statistically different from zero. The safety benefits of pipeline upgrades are also noisy, with the largest point estimate implying a benefit of \$2.65/Mcf (note this would be in addition to the \$0.08/Mcf in associated leak reductions). The noise is not surprising given that the typical utility in our sample has one accident every ten years, ignoring third-party damages. 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 with utility fixed effects (which we are reluctant to rely upon).

In Section 3.1, we concluded that utilities have been abating at a cost below the theoretical socially optimal cost. This was based on point estimates of abatement costs of around \$0.48/Mcf. We then compared this to the commodity value that utilities faced (sales-weighted citygate prices for financial reporters after 2010, \$5.67/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.

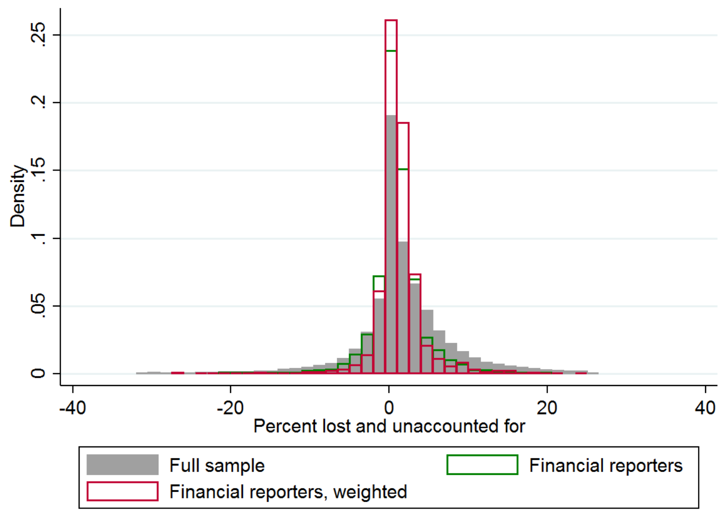
In Section 3.2, we concluded that the levelized cost of pipeline replacement (\$48/Mcf to \$211/Mcf, from Table 5) is well above the cost of historically undertaken leak detection and repair activities. In addition, our preferred set of parameters implied a levelized cost of abatement well above the 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 A11 are consistent with this intuition. The largest value of safety benefits we estimate for pipeline replacement ($2.74/Mcf) would 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 effectiveness 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 A12 provides robustness checks for Table 6, on what is correlated with utility expenditures. The first two columns provide the following robustness checks: alternative controls (Column 1); and a subsample of utilities (Column 2). The next two columns compare the estimates from Table 6 with the reduced-form estimates underlying our main O&M estimation. A somewhat different set of control variables is used across these two specifications, but the coefficient on the instrument ("Past volume leaked$\times$I(Post-PHMSA)") is reassuringly similar.

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 (grey) versus just those utilities reporting financial information (green). It additionally shows the impact of weighting by firm size (red). 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.

Table A1: Leak Rates

	(1) % Leaked	(2) % Leaked	(3) % Leaked	(4) % Leaked	(5) % Leaked
Average pipeline age, years	0.016***	0.017**	0.017***	0.016***	0.021
	(0.005)	(0.009)	(0.006)	(0.006)	(0.014)
Plastic or high-quality steel, %	-0.022***	-0.021	-0.037***		-0.011
	(0.008)	(0.013)	(0.010)		(0.015)
Unprotected coated steel, %				-0.029**	
				(0.011)	
Cathodically protected bare steel, %				-0.034***	
				(0.010)	
Cathodically protected coated steel, %				-0.032***	
				(0.009)	
Plastic, %				-0.032***	
				(0.009)	
Cast iron, %				-0.018	
				(0.016)	
Ductile iron, copper, or other, %				-0.023**	
				(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	9,334	10,112	6,952	9,334	9,334
R^2	0.09	0.06	0.10	0.09	0.43

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) uses a balanced panel of bundled-only utilities. 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 A2: O&M Abatement Expenditures: Robustness using Different Instruments

	IV				
	(1) O&M	(2) O&M	(3) O&M	(4) O&M	(5) O&M
Volume leaked, Mcf	0.00	-1.38	-0.49	-0.78	-0.53
	(0.51)	(2.05)	(2.08)	(0.69)	(0.85)
Controls	Yes	Yes	Yes	Yes	Yes
Region-year effects	Yes	Yes	Yes	No	No
Cubic time trends by region	No	No	No	Yes	Yes
Utility effects	Yes	Yes	Yes	Yes	Yes
Observations	1,551	1,399	2,557	1,569	1,551
Kleibergen-Paap F-stat.	24.43	7.81	9.78	13.30	14.74
Difference from citygate price ($/Mcf)	5.67***	4.29**	5.18**	4.89***	5.14***

Notes: Using different instrumental variables for volume of leaked gas. Instruments are variants of the interaction term used as our main instrument in Table 3: (1) Instrument is scaled by the utility's total purchased volume, instead of pipeline miles; (2) Instrument uses the volume leaked in 2004 as the pre-period; (3) Instrument uses the average volume leaked between 1995 and 2009 as the pre-period and regression uses all years of data; (4) Instrument is the indicator of the period after PHMSA increased regulations, instead of the interaction; (5) Two instruments: the interaction used in Table 3 as well as the indicator of the period after PHMSA increased regulations. *** Statistically significant at the 1% level; ** 5% level; * 10% level.

Table A3: Reverse IV: Volume of Gas Leaked on Operations and Maintenance Expenditures

	OLS	IV
	(1) Vol. Leaked	(2) Vol. Leaked
O&M expenses, $	-0.01	-2.07
	(0.01)	(3.94)
Controls	Yes	Yes
Region-year effects	Yes	Yes
Utility effects	Yes	Yes
Observations	1,579	1,551
Kleibergen-Paap F-stat.	.	0.27
Abatement cost ($/Mcf)	-91.18	-0.48
Difference from citygate price ($/Mcf)	-85.51	5.19***

Notes: Coefficients represent the Mcf reduced per $ spent. The instrument is the utility's average volume of leaked gas in the period before PHMSA increased regulations, interacted with a dummy for the period after PHMSA increased regulations. Controls are total volume sold; total miles of pipeline mains; total service line counts; low-quality pipeline miles; and low-quality service line counts. All variables are scaled by the utility's average count of pipeline miles over the sample period. Standard errors are clustered by utility. *** Statistically significant at the 1% level; ** 5% level; * 10% level.

Table A4: O&M Abatement Expenditures: Robustness to Alternative Specifications

	Different Controls						Diff. Samples		Weighting	Different Definitions						
	(1) O&M	(2) O&M	(3) O&M	(4) O&M	(5) O&M	(6) O&M	(7) O&M	(8) O&M	(9) O&M	(10) O&M	(11) O&M	(12) O&M	(13) O&M	(14) O&M + Capital	(15) All Expenses	(16) O&M
Volume leaked, Mcf	-0.59	-0.50	-0.82	-0.38	1.18	1.15	-1.16	-0.36	-1.15	-0.49	-0.26	-0.53	-1.73	-0.12	2.23	-0.61
	(0.95)	(0.93)	(0.95)	(0.84)	(1.18)	(1.15)	(0.80)	(0.92)	(3.26)	(0.80)	(0.44)	(0.62)	(1.50)	(1.16)	(2.13)	(0.67)
Utility effects	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Region-year effects	No	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No
Region-period effects	No	No	No	No	No	No	No	No	No	No	No	No	No	No	No	Yes
Year effects	Yes	Yes	No	No	No	No	No	No	No	No	No	No	No	No	No	No
Controls	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	No	No	Yes	Yes	Yes
Cubic regional time trends	No	Yes	No	No	No	No	No	No	No	No	No	No	No	No	No	No
Past leaks*Year	No	No	No	No	Yes	No	No	No	No	No	No	No	No	No	No	No
Utility effects*Year	No	No	No	No	No	Yes	No	No	No	No	No	No	No	No	No	No
Cubic sales control	No	No	No	Yes	No	No	No	No	No	No	No	No	No	No	No	No
Observations	1,551	1,551	1,576	1,524	1,551	1,551	772	1,521	1,413	1,582	1,433	1,551	1,551	1,441	1,441	332
Kleibergen-Paap F-stat.	15.88	17.90	16.54	15.66	13.46	12.45	15.69	17.39	13.73	12.19	27.12	16.37	14.36	17.85	17.85	20.22

Notes: Specifications are variants of the IV specification in Table 3. Columns are: (1) Year effects instead of region-year effects; (2) Post-PHMSA indicator and cubic of regional time trends instead of region-year effects; (3) Not including control variables; (4) Including retail price and cubic of sales; (5) Past leaks interacted with year trend; (6) Utility fixed effects interacted with year trend; (7) Balanced sample of only utilities with residential-bundled sales; (8) Excluding California utilities; (9) Weighting by portion of purchases at citygate (i.e., non-transmission or storage volumes); (10) Trimming upper and lower 1% of leaked gas (instead of 5%); (11) Dropping outliers instead of winsorizing; (12) Not dropping or winsorizing outliers; (13) No scaling. (14) O&M expenditures as well as annuitized capital expenditures; (15) O&M expenditures as well as transmission, storage, information, administration, and annuitized capital expenditures; (16) Collapsing across years to two periods (pre and post). *** Statistically significant at the 1% level; ** 5% level; * 10% level.

Table A5: Subcategories of Operations and Maintenance Expenditures

Category	OLS (1) Estimate, \$/Mcf	IV (2) Estimate, \$/Mcf
Operations: Supervision & Engineering	-.032	.173
	(.028)	(.192)
Operations: Distr Load Dispatching	.007	-.056
	(.012)	(.064)
Operations: Compressor Station Labor	0	-.001
	(.001)	(.003)
Operations: Compressor Stat Fuel & Power	0	0
	(0)	(.001)
Operations: Mains & Services	.039	.253
	(.045)	(.24)
Operations: Meas & Reg Station, General	-.007	.007
	(.007)	(.03)
Operations: Meas & Reg Station, Industrial	.003*	.013
	(.002)	(.01)
Operations: Meas & Reg Station, City Gate	0	0
	(.002)	(.009)
Operations: Meter & House Regulator	-.07	-.357**
	(.054)	(.155)
Operations: Customer Installation	-.018	-.298
	(.041)	(.314)
Operations: Other Expense	.023	-.009
	(.027)	(.125)
Operations: Rents	-.01	.038
	(.009)	(.04)
Maintenance: Supervision & Engineering	.022	-.1
	(.025)	(.122)
Maintenance: Structures & Improvements	-.008*	-.005
	(.004)	(.026)
Maintenance: Mains	-.1*	-.212
	(.058)	(.749)
Maintenance: Compressor Station Equipment	0	-.005
	(0)	(.004)
Maintenance: Meas & Reg Station, General	-.007	.006
	(.007)	(.028)
Maintenance: Meas & Reg Stat, Industrial	-.001	-.005
	(.001)	(.006)
Maintenance: Meas & Reg Station, City Gate	-.003	-.012
	(.004)	(.012)
Maintenance: Services	-.033*	-.199**
	(.02)	(.082)
Maintenance: Meters & House Regulators	-.012	.012
	(.018)	(.079)
Maintenance: Other Equipment	.003	.036
	(.01)	(.033)

Notes: Each point estimate is the coefficient on volume of leaked gas obtained from one of 44 separate regressions. The rows vary by dependent variable, covering the comprehensive list of 22 subcategories of distribution O&M expenditures. The columns mirror the specifications in Table 3: Column (1) is the OLS specification and Column (2) instruments for the quantity of leaked gas using past leaked gas interacted with the period after PHMSA increased stringency.

Table A6: Instrumenting for Pipeline Replacement: First Stage of Capital Cost Regression

	(1)
	Low Quality Mains Replacement
Historic low-quality mains, miles	0.18***
	(0.03)
Δ volume sold, Bcf	0.24
	(0.38)
Δ mains, miles	-0.05***
	(0.02)
Δ customers	0.00
	(0.00)
Region effects	Yes
Observations	140
Kleibergen-Paap F-stat.	40.02

Notes: Results show the first stage regression corresponding to Table 4. Dependent variable is the replacement of low quality mains from 2004 to 2013. The instrument is the miles of low quality mains in 2004. All variables are scaled by the utility's average count of pipeline miles over the sample period. Robust standard errors in parentheses. *** Statistically significant at the 1% level; ** 5% level; * 10% level.

Table A7: Cost of Pipeline Replacement: Robustness to Alternative Specifications

	Total Capital Expenditures ($000)						
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
	O&M+Capital	All Capital	Alt. Capital	Capital	Capital	Capital	Capital
Low-quality main replacement, miles	2,069***	1,214**	1,232***	1,229***	1,479***	1,571***	1,868***
	(792)	(505)	(407)	(438)	(562)	(556)	(313)
Observations	140	140	129	141	79	136	140
Kleibergen-Paap F-stat.	40.02	40.02	39.75	64.90	47.27	30.57	80.79

Notes: Column (1) includes O&M in addition to Capital. Column (2) includes all gas-related capital, not just distribution-specific gas-related capital. Column (3) uses an alternative reporting of capital: the change in accumulated capital rather than the sum of capital additions. Column (4) has no controls. Column (5) uses data from 1998 to 2013 instead of 2004 to 2013 and uses low quality pipes in 1998 as the instrument. Column (6) weights by portion purchases made at the citygate (i.e., non-transmission and storage volumes). Column (7) does not scale. Robust standard errors in parentheses. *** Statistically significant at the 1% level; ** 5% level; * 10% level.

Table A8: Estimating an Emissions Factor: Volume Leaked on Miles Replaced

	(1) Volume Leaked	(2) Volume Leaked
Lagged low-quality mains, miles	400.46***	573.18***
	(24.69)	(67.22)
Lagged medium quality mains, miles	23.96	294.99**
	(15.65)	(117.55)
Lagged volume sold	0.00***	0.00***
	(0.00)	(0.00)
Lagged pipeline mains, miles	15.18	-226.77*
	(31.85)	(117.91)
Region-year effects	Yes	Yes
Observations	8,689	1,410
R^2	0.08	0.17

Notes: Dependent variable is the volume of leaked gas (Mcf). Column (1) includes all data, not only the financial reporters. Column (2) only includes financial reporters. Coefficient on "Lagged low-quality mains" in Column (2) serves as the emissions factor of gas leaked per mile of low-quality pipe, in Mcf/mile. 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. The omitted category of mains is high-quality mains: protected coated steel and plastic. All variables are scaled by the utility's average count of pipeline miles over the sample period. Standard errors are clustered by utility. *** Statistically significant at the 1% level; ** 5% level; * 10% level.

Table A9: 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
Excess flow valves for new services	$2.20
Pneumatic devices, retrofit	$2.93
Pneumatic device, early replacement	$7.11
More frequent walking surveys	$7.33
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. Programs and equipment are assumed in this calculation to last one year, with the exception of excess flow valves. Some documentation suggests 50-year lifetimes for excess flow valves; here we have assumed a more conservative 25 year lifetime and a 3 percent discount rate.

Table A10: 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 A11: Damages from Accidents

	OLS		IV
	(1) Damages ($)	(2) Damages ($)	(3) Damages ($)
Volume leaked, Mcf	0.08	0.02	0.19
	(0.07)	(0.06)	(0.26)
Low-quality mains, miles	607.94**	-120.91	433.14
	(293.58)	(301.68)	(2,105.43)
Controls	Yes	Yes	Yes
Region-year effects	Yes	Yes	Yes
Utility effects	No	Yes	Yes
Observations	3,319	3,319	3,127
Kleibergen-Paap F-stat.			14.01
Implied leak abatement benefit, $/Mcf	0.08	0.02	0.19
	(0.07)	(0.06)	(0.26)
Implied pipeline replacement benefit, $/Mcf, F=229	2.65**	-0.53	1.89
	(1.28)	(1.32)	(9.19)
Implied pipeline replacement benefit, $/Mcf, F=470	1.29**	-0.26	0.92
	(0.62)	(0.64)	(4.48)

Notes: These 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. Dependent variable is the aggregate of property damages, lost lives, using a Value of a Statistical Life of $9.1 million, and injuries, using a value of $1 million per injury. Column (3) instruments for both explanatory variables using the interaction of historical count of low quality mains and an indicator for the period after PHMSA regulations increased in stringency; and the interaction of historical volume leaked and an indicator for the period after PHMSA regulations increased in stringency. The implied leak abatement benefits in $/Mcf for are simply equal to the coefficient on "Volume leaked, Mcf." The implied pipeline benefits re-scale the coefficient on "Low-quality mains, miles" by an emissions factor, in Mcf/miles, of either 229 or 470. All three specifications control for: region-year effects; total miles of pipeline mains; and total volume sold. All variables are scaled by the utility's average count of pipeline miles over the time period. 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 A12: Robustness: Reduced-Form Estimates of What Explains Utility Expenditures

	Alternative Specifications		Specification Comparison	
	(1) Total ($)	(2) Total ($)	(3) O&M ($)	(4) O&M ($)
Past volume leaked×I(Post-PHMSA)	1.33	0.35	0.30	0.21
	(1.51)	(0.94)	(0.39)	(0.43)
Economic and Regulatory Variables:				
City-gate price, $/Mcf	-227	-37	-46	
	(264)	(168)	(48)	
Fraction of year in a rate case	1339**	1242**	307**	
	(642)	(618)	(151)	
Fraction of year in a rate-case test year	739	903*	179***	
	(525)	(457)	(59)	
I(Utility has pipeline rider)	2513**	1081	-35	
	(1023)	(831)	(160)	
Controls:				
Pipeline mains, miles	16038**	-2629	836	1090
	(7790)	(1961)	(757)	(811)
Service lines, count	11.85	23.32	3.76	9.32
	(58.39)	(23.40)	(11.48)	(13.33)
Volume sold, Mcf	-0.05	0.14	0.03	0.02
	(0.18)	(0.14)	(0.03)	(0.03)
Low-quality mains, miles				-2187
				(4180)
Low-quality service lines, count				-28.35
				(26.36)
Region-year effects	No	Yes	Yes	Yes
Year effects	Yes	No	No	No
Utility effects	Yes	Yes	Yes	Yes
Observations	1,490	704	1,603	1,559
R^2	0.83	0.85	0.97	0.97

Notes: Regressions show the reduced-form regressions of expenditures on our instrument (the utility's past leak volume interacted with the period that PHMSA increased regulatory stringency), along with other economic and regulatory variables. The dependent variable in the first two columns is the sum total of capital and O&M expenditures in dollars. Columns show alternative specifications to the total-expenditure regression found in Table 6: Column (1) includes year effects instead of region-year effects. Column (2) uses a balanced sample of bundled-only utilities. The last two columns compare the estimates from the regressions exploring what drives abatement with the reduced-form version of our main O&M estimation: Column (3) is the O&M counterpart of the previous three columns (this specification is also found in Table 6). Column (4) is the reduced form of our main estimation result (Table 3). All variables are scaled by the utility's average count of miles of pipeline mains over the sample period, except price, fractions, and indicator variables. Standard errors are clustered by utility. *** Statistically significant at the 1% level; ** 5% level; * 10% level.