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Do Americans consume too little natural gas? An empirical test of marginal cost pricing

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This article measures the extent to which prices exceed marginal costs in the U.S. natural gas distribution market during the period 1991–2007. We find large departures from marginal cost pricing in all 50 states, with residential and commercial customers facing average markups of over 40%. Based on conservative estimates of the price elasticity of demand, these distortions impose hundreds of millions of dollars of annual welfare loss. Moreover, current price schedules are an important preexisting distortion which should be taken into account when evaluating carbon taxes and other policies aimed at addressing external costs.

1. Introduction

■ Energy plays a central role in determining our overall economic well-being, from heating and cooling our homes and businesses to determining the cost and composition of goods and services produced in the economy. It is crucial that energy be priced appropriately to correctly encourage efficient choices within and across different energy sources. These choices are particularly important given recent increased attention to the external costs of energy. In the United States, 81% of greenhouse gas emissions are derived directly from the production and consumption of energy.[1] There is a great deal of public interest, therefore, in making energy prices accurately reflect both private and social costs.

The standard approach for addressing externalities is to use a Pigouvian tax or, similarly, a cap-and-trade program. In the standard case, a tax works by increasing prices to reflect marginal damages. Adding marginal damages on top of private marginal costs gives social marginal costs, leading to the socially optimal level of production. This solution is predicated on the idea that, in the absence of the tax, prices are equal to private marginal cost. This is a reasonable assumption

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[1] U.S. Department of Energy, Energy Information Administration, "Emissions of Greenhouse Gases in the United States 2008," DOE/EIA-0573, released December 2009.

in perfectly competitive markets. However, this assumption may be less reasonable for markets served by regulated natural monopolies, which include the vast majority of retail natural gas and electricity sales in the United States. For these markets, the welfare consequences of a tax depend on how regulated prices compare to private marginal cost. If regulated prices are not set equal to marginal cost, the standard Pigouvian solution will not work and may actually exacerbate existing market distortions.

We focus, in particular, on natural gas distribution in the United States. This is a clear natural monopoly with high fixed costs and low marginal costs. Like other monopolies, natural gas distributors would, if left unregulated, maximize profit by pricing above marginal cost. A standard result in regulation is that it is possible to achieve the efficient solution by using a two-part tariff. By setting marginal price equal to marginal cost, the regulator increases the level of production and eliminates the deadweight loss associated with the monopoly. The regulator can then allow the monopolist to recoup its fixed costs by charging fixed fees that do not depend on the level of production. Two-part tariffs are commonly used in regulating natural gas distributors, with customers paying both a fixed monthly fee and a price per unit of consumption.

In this article, we measure the extent to which actual two-part tariffs for natural gas differ from the theoretical ideal of marginal cost pricing. We find that markups differ dramatically by customer class. Whereas industrial customers face prices that are close to marginal cost, most residential and commercial customers face prices closer to average cost, with most revenues coming from per-unit charges rather than through fixed monthly fees. Based on conservative estimates of the price elasticity of demand, our results imply that the current pricing system yields annual welfare losses of \$2.7 billion compared to marginal cost pricing. This represents approximately 3% of the \$92 billion of total expenditures on natural gas in the United States in 2008.

On average, we estimate that residential and commercial customers face markups of over 40% above marginal cost. The average markups for residential and commercial customers (\$3.38 and \$3.05 per McF, respectively) are equivalent to taxes of over \$55 per ton of carbon dioxide (\$200 per metric ton of carbon).[2] This is substantially higher than the level of a carbon tax envisioned by most economists. As a point of comparison, Nordhaus (2007) calculates a baseline optimal tax of \$10 per ton of carbon dioxide.[3] Thus, residential and commercial customers may already be facing a marginal price that is above the social marginal cost of natural gas. If this is the case then imposing a Pigouvian tax would move consumption in the wrong direction, further reducing consumption below the efficient level. The broader policy lesson from our analysis is that pre-existing distortions from regulated natural monopolies are important to consider when evaluating carbon taxes and other policies that would increase the marginal price of energy products.

We then discuss possible explanations for the observed rate structures. Cost recovery is a central feature of the current regulatory environment, but cost recovery alone cannot explain why per-unit charges tend to be marked up considerably whereas fixed monthly fees are consistently very low across states and customer classes. In part, this preference for low fixed fees may reflect efforts by regulated companies to maximize the total number of customers and thus the total rate base (see Sherman and Visscher, 1982). Distributional considerations provide an additional and complementary explanation. Under current price schedules, high-volume customers pay a disproportionately large share of fixed costs, and attempts to "levelize" price schedules typically face substantial political opposition because higher fixed fees would result in increased expenditures for low-volume customers.

[2] U.S. Department of Energy, Energy Information Administration, "Documentation for Emissions of Greenhouse Gases in the United States (2005)," October 2007, DOE/EIA-0638, Table 6-4. There are .0543 metric tons of carbon dioxide (CO_2) per thousand cubic feet (McF) of natural gas.

[3] A carbon tax of \$35 per ton from Nordhaus (2007) implies a tax of \$10 per ton of CO_2 because the atomic weight of carbon is 12 atomic mass units, whereas the weight of CO_2 is 44, so one ton of carbon equals 44/12 tons of CO_2. To avoid confusion we use CO_2 throughout.

Finally, the article considers available policy approaches for addressing these departures from marginal cost pricing. One alternative is public ownership. Comparing revenues from municipally owned and investor-owned distribution companies, we find that approximately 25% of a municipally owned utility's fixed costs are borne by taxpayers rather than consumers of natural gas. Lower revenue requirements could allow municipally owned companies to charge marginal prices which are closer to marginal cost, reducing deadweight loss. Of course, these subsidies must be financed through taxes. Because the government cannot collect nondistortionary taxes, the welfare effects of public provision are ambiguous—welfare for natural gas consumers rises if subsidies lower marginal prices, but tax collection introduces distortions in other parts of the economy.

The article proceeds as follows. Section 2 describes relevant background information about the organization of the natural gas market. Section 3 describes the 17 year state-level panel of prices and quantities assembled for the analysis. Section 4 presents the results of our test of marginal cost pricing and measures of the total welfare loss compared to marginal cost pricing. Section 5 discusses the causes and consequences of the current rate structure with emphasis on implications for carbon policy. Section 6 compares regulated prices for municipally owned and investor-owned distribution companies, and Section 7 concludes.

2. Background

■ This section provides a brief description of the organization of the U.S. natural gas market, highlighting the features of the market that are relevant for the analysis and providing a bridge to a substantial theoretical literature in industrial organization on the optimal regulation of natural monopoly. For more information about the organization and regulatory history of the U.S. natural gas market, see Viscusi, Harrington, and Vernon (2005) and U.S. Department of Energy (2010).

The natural gas market in the United States consists of gas producers, interstate pipeline operators, and local distribution companies (LDCs). This article focuses on LDCs and on the price schedules faced by residential, commercial, and industrial customers. The costs in this market are widely understood. The main fixed cost for the LDC is the installation and maintenance of the pipeline network. In addition, LDCs incur costs installing and maintaining gas meters, processing bills, and taking customer service calls. These costs depend critically on the total number of customers, and the "marginal customer cost"; that is, the cost of adding an additional customer to the network is substantial. In addition, LDCs purchase natural gas. Commodity cost for LDCs is measured by the "city-gate price," the price at which the LDC receives natural gas.[4] The marginal cost of distributing gas through the local pipeline network is virtually zero for all classes of consumers. Our conversations with industry participants and examinations of industry filings confirm that line losses are negligible, representing a tiny fraction of total costs. Thus the marginal cost of providing an additional unit of natural gas to an existing customer is well-approximated by the city-gate price.

LDCs are regulated by state utility commissions, which set tariff schedules for each customer class using traditional rate-of-return techniques.[5] Regulators create price schedules to equate total revenues from all customer classes with total operating costs plus an allowed rate of return on the firm's capital expenditures. There are many different price schedules which would satisfy the zero-profit condition, and several previous studies have considered the question of which

[4] From a research perspective, a significant advantage of natural gas distribution compared to many other markets is that marginal costs are observed. This is important because although an extensive literature in industrial organization has been developed for inferring marginal cost based on pricing behavior, this approach is problematic for studies of regulated firms because prices for these firms are established by regulators, causing the key identification assumption to fail. Not only do we observe marginal costs but they are observed for all 50 states and at a monthly frequency going back to 1991.

[5] Price controls on wellhead prices were a major feature of the U.S. natural gas market for much of the postwar period (see, e.g., Davis and Kilian, 2008) but were terminated in 1989 before the beginning of our sample period.

schedule yields the highest level of utility. If constrained to use linear prices, Boiteux (1956) shows that the welfare-maximizing price markup is proportional to the inverse of the elasticity of demand. Specifically, if a monopolist produces N goods (or serves N different customer classes) with total cost function $C(x_1, x_2, \ldots, x_I)$ and faces inverse demand function $p_i(x_i)$ for good i, a social planner constrained to using linear prices can maximize social surplus by setting prices

$$\frac{p_i - \dfrac{\partial C(X)}{\partial x_i}}{p_i} = -\left(\frac{\partial p_i}{\partial x_i}\frac{x_i}{p_i}\right)\left(\frac{\lambda}{1+\lambda}\right),$$

where λ is a nonnegative constant. These prices are called "Ramsey-Boiteux" prices because the problem considered by Boiteux (1956) is formally identical to the constrained maximization problem solved by Ramsey (1927).

When nonlinear prices can be used, the regulator has more flexibility. This is the case in practice with natural gas distribution, where the dominant price schedule is a two-part tariff.[6] First, LDCs typically charge customers a fixed fee, typically levied monthly, that does not depend on the level of consumption. This fee varies by customer class—typically, industrial customers pay a higher monthly fee from residential or commercial customers. In some cases, the fixed fee also varies within customer class—for example, residential customers who use natural gas for heating may be charged a different fee from residential customers who do not use natural gas for heating. Second, customers pay a per-unit charge for each unit of natural gas that is consumed. This price includes a commodity charge for natural gas purchased on their behalf by the local distribution company. Commodity costs change throughout the year with the LDCs' procurement costs, and typically changes in commodity costs are passed on relatively quickly to final customers.[7] In addition to commodity costs, most companies also charge customers a per-unit "transportation charge" per unit of natural gas consumed. This is typically a price per unit, although in some cases commodity costs are marked up by a fixed percentage. As we illustrate in Section 4, these per-unit fees imply that LDC revenues are highly seasonal, with LDCs collecting a large share of their total annual revenue during cold, high-demand winter months.

In theory, with two-part tariffs, a regulator can set marginal prices equal to marginal costs. As first suggested by Coase (1946), two-part tariffs can be adjusted such that the per-unit charge is equal to marginal cost and the fixed fee is set to cover fixed costs. For the relevant case with declining average costs and constant marginal costs, this implies that the fixed fee would be set equal to each customer's share of the LDC's fixed costs. Baumol and Bradford (1970), Ng and Weisser (1974), Schmalensee (1981), and Sherman and Visscher (1982) extend the analysis of two-part tariffs, solving for optimal tariffs with and without revenue constraints. If this efficient two-part tariff is not sufficient to cover the monopolist's fixed costs, then both prices are marked up by an amount inversely proportional to the elasticity of demand for that margin.

In summary, this study examines the regulation of natural gas LDCs. A standard result in regulation is that efficiency requires that marginal prices be set equal to marginal costs. The availability of two-part tariffs makes it possible to use marginal cost pricing whereas still allowing the LDC to recuperate fixed costs. How marginal prices compare to marginal costs in practice is an empirical question to which we turn in the following section.

[6] Typically LDCs use simple two-part tariffs, although multiple-part tariffs are not uncommon. We examined the 2007 tariff schedules of the 12 largest investor-owned distribution companies and the 6 largest municipally owned distribution companies. Two-part tariffs are the dominant price schedule throughout. For the LDCs we surveyed, 10 of the 18 companies use multiple-part tariffs for at least one category of customers.

[7] Friedman (1991) provides a fascinating description of electricity and natural gas rate making in California under the California Public Utility Commission. Typically every three years there is a rate case with more frequent rate adjustments for commodity cost changes. "Substantively, each case proceeds in the same way. First, the utility's revenue requirement and marginal costs are determined. Second, the commission comes to a broad decision about how to allocate that revenue among customer classes. Finally, actual rates within classes are set to raise the allotted revenue. See also Kahn (1994) for an additional description of the rate-making process including a detailed example from Pacific Gas and Electric.

3. Data

■ To measure the extent to which regulated prices differ from marginal cost pricing, we assembled a 17 year panel of natural gas sales and prices at the stat level. Our sample includes the entire period for which data are available, January 1991 through December 2007. Natural gas sales and prices come from the U.S. Department of Energy, Energy Information Administration (EIA), "Natural Gas Navigator." The Department of Energy constructs these data using a monthly survey (EIA Form-857) of natural gas distribution companies. These data describe natural gas sales separately for residential, commercial, industrial, and electric utility customers. See Department of Energy, Energy Information Administration, "Definitions, Sources and Explanatory Notes" for details.

In states with active retail choice programs such as Georgia, Maryland, New York, Ohio, Pennsylvania, and Virginia, the Energy Information Administration calculates natural gas sales, and prices come from both the monthly survey of LDCs (EIA Form-857) and a monthly survey of natural gas marketers (EIA Form-910). In these states, customers have a choice between buying natural gas from their LDC and buying natural gas from independent natural gas marketers. The LDC provides and is reimbursed for transportation services but marketers perform the financial transactions, procuring natural gas in the wholesale market and then selling it to final customers. For states with retail choice programs, our panel describes total sales and average prices for all customers by state, month, and customer class.

In this article, we focus on sales to residential, commercial, and industrial customers. We omit electric utility consumers. These facilities consume sufficiently large amounts of natural gas such that it is often profitable to build a dedicated line directly to an interstate pipeline, contract with suppliers directly, and bypass the LDC. Consequently, LDCs have little bargaining power with respect to electric utility customers and they tend to face very different price schedules from other customers. Similarly, among commercial and industrial customers, we exclude what are called "noncore" customers.[8] Whereas "core" customers must buy from the LDC, noncore customers by virtue of their size or other factors can buy from third parties and then contract with the LDCs for transportation services only. Much like electric utility customers, noncore customers have negotiating power, which allows them to typically obtain price schedules that are different from the schedules faced by most customers. Both the prices and quantities used in the analysis exclude noncore customers.

Prices are available by state, month, and customer class and include all charges paid by end users including transportation costs as well as all federal, state, and local taxes. Also available by state and month are city-gate prices, the price paid by the LDC when they receive deliveries at the entrance to the distribution network. Table 1 presents descriptive statistics for the monthly data: consumption and average delivered prices by customer class, city-gate prices, the spot price for North Sea crude oil (Brent crude spot price), and heating degree days. All dollar values in the article have been normalized to reflect year 2007 prices. In addition to the monthly survey data from EIA Form-857, we assembled annual utility-level data for the universe of distribution companies delivering natural gas to end users from EIA Form-176. The EIA does not release any utility-level data at the monthly level. In the annual data, we observe sales, revenues, and number of customers for each LDC. In addition, we know firm ownership, which allows us to compare regulated prices of investor-owned and municipally owned distribution companies in Section 6.

In regulated natural gas markets, marginal prices change in two ways. First, the underlying commodity cost for the LDCs may change if natural gas prices rise nationally. Second, regulators may change the fixed monthly fees and per-unit markups as a result of a rate case. Natural gas commodity prices change from month to month with national production and consumption. Fixed monthly fees and per-unit markups, on the other hand, adjust infrequently—they are periodically

[8] Whereas a relatively high proportion of commercial demand comes from core customers, most industrial customers contract with wholesaler natural gas providers directly. From 2002 to 2007, approximately 79% of commercial natural gas demand came from core customers. For industrial demand, approximately 23% of demand came from core customers.

TABLE 1 Summary Statistics, by Sector

Variable	Observation	Mean	Standard Deviation	Minimum	Maximum
Monthly Consumption (millions cubic feet)					
Residential	12,172	7,806	12,900	12	104,000
Commercial	12,139	4,854	6,454	37	51,600
Industrial	4,671	11,600	22,200	0	198,000
Electric	4,527	10,100	21,500	0	193,000
Monthly Consumption per Customer (McF per Customer)					
Residential	11,623	7.00	5.55	0.54	31.30
Commercial	11,608	52.31	34.59	2.17	284.31
Industrial	4,150	50,478	159,474	14.27	1,167,727
Average Delivered Price ($ 2007 per McF)					
Residential	12,171	11.45	4.63	3.00	57.38
Commercial	12,160	8.84	3.48	2.11	74.57
Industrial	4,684	8.82	3.06	1.44	32.71
Electric	2,657	7.44	2.54	1.34	25.83
City-gate price ($ 2007 per McF)	12,169	5.78	2.66	0.40	37.74
City-gate price from platts ($ 2007 per McF)	10,584	4.42	2.17	1.06	25.61
Brent spot price ($ 2007 per bbl)	11,628	33.42	16.05	12.20	92.41
Heating degree days	11,040	431.1	419.4	0	2,109

Note: Consumption and price data for residential and commercial customers begin in 1989. Consumption and price data for industrial customers begin in 2001. Platts spot prices are unavailable for 1989 and for the states of Alaska and Hawaii.

set during rate cases and held constant until the following review, which could be anywhere from one to several years later. Although both of these are likely to be exogenous with respect to local demand conditions, our empirical framework emphasizes within-year changes. Consequently, our results are less likely to be driven by spurious changes in regulated prices.

City-gate prices play a critical role in the analysis that follows because they represent the marginal cost of natural gas for LDCs. Our primary source of city-gate prices is the Platts's GASdat database, which describes daily natural gas spot prices from 131 different locations throughout the United States.[9] Platts obtains these prices via surveys of trades made at each location, and they represent true natural gas spot prices. We aggregate these city-gate prices to the monthly level and then calculate state averages across all locations in a given state. For states without Platts survey locations, prices from the closest available location are used.[10]

We also perform our empirical test of marginal cost pricing using an alternative set of city-gate prices derived from an entirely independent source. These alternative prices come from EIA Form-857 and represent the city-gate prices reported by LDCs including, "commodity charges, monthly minimum bill and/or take-or-pay charges, surcharges, refunds in the form of reduced charges, charges incidental to underground storage of company-owned gas, and transportation charges paid or incurred to deliver gas to your distribution area." Although many of these costs indeed reflect the true marginal cost of natural gas to the LDC, one might be concerned, for example, by the monthly minimum bill charges which should be correctly thought of as a fixed fee rather than as a marginal cost. In addition, LDCs enter long-term contracts and engage in hedging transactions, so costs in a particular month may be a poor proxy for marginal commodity costs. These concerns led us to focus primarily on our measure of city-gate prices

[9] In practice, LDCs procure natural gas both on the spot market and in a forward market called the "bidweek market" in which the LDC purchases a specified volume of natural gas every day over the course of a month. Participating in this forward market reduces the volatility of expenditures but not the marginal cost of natural gas because at the margin, LDCs always have the option to buy (or sell) natural gas on the spot market. See Borenstein, Busse, and Kellogg (2009) for a detailed description of how LDCs procure natural gas.

[10] When performing the test with Platts data we exclude Alaska and Hawaii, as there are no Platts survey locations in or near these states.

from Platts. Nonetheless, it is reassuring that the results are generally very similar using both measures.

Table 1 reports summary statistics for both measures of the city-gate price. The price from the EIA tends to be somewhat higher, consistent with including additional nonmarginal costs. Overall, however, the two prices track each other fairly accurately and the correlation between the two monthly price series is 78.1%.[11]

The analysis which follows is performed at the monthly level. Although there is daily variation in city-gate prices, short-run variation in natural gas prices is mitigated by the ability of natural gas suppliers to store natural gas. In the United States, total natural gas storage capacity exceeds eight trillion cubic feet, enough to meet total consumption for several months. In addition, natural gas transmission lines themselves are a form of storage, as they can accommodate a range of different levels of pressurization. With access to storage, natural gas suppliers are able to arbitrage within-month price differences, and on average across states in our sample the month-to-month variation represents 94% of the total variation in city-gate prices whereas the within-month variation represents only 6%. Our deadweight loss estimates in Section 4 calculate the gain in welfare that could be realized by moving to a system of monthly marginal cost pricing. Additional gains could be realized by moving to marginal cost pricing, where prices vary daily. Still, the monthly level counterfactual makes the most sense from a policy standpoint. Current metering technology does not record daily consumption levels, so a change to daily pricing would require large changes in metering infrastructure along the same lines currently being observed in electricity. Moreover, utilities have been historically very resistant to more dynamic forms of pricing, even in electricity markets where cost-effective storage is not available so the potential welfare gains are considerably larger.

4. Results

□ **A test of marginal cost pricing.** This section describes our test of marginal cost pricing and our estimation of per-unit markups. Efficiency requires per-unit prices to be equal to the marginal commodity cost of natural gas. Or, equivalently, efficiency requires that revenue net of commodity costs should not be a function of the level of consumption. For each state, month, and customer class we calculate "net revenue," the total revenue collected by LDCs net of commodity costs. Next, we test whether net revenue is a function of the level of natural gas consumption.

The best way to understand our test is by example. Figure 1 plots consumption and net revenue by month for residential natural gas customers in Massachusetts in 2006. Natural gas consumption varies substantially throughout the year, with per-capita consumption increasing by a factor of five between summer and winter months as more natural gas is used for home heating. Net revenue follows a similar pattern, increasing substantially with per-capita consumption and peaking in the winter. In addition to the monthly observations, the figure also plots fitted values from the following regression equation:

$$NR_t = \alpha_0 + \alpha_1 q_t + \epsilon_t, \quad t \in 1, 2, \ldots, 12, \tag{1}$$

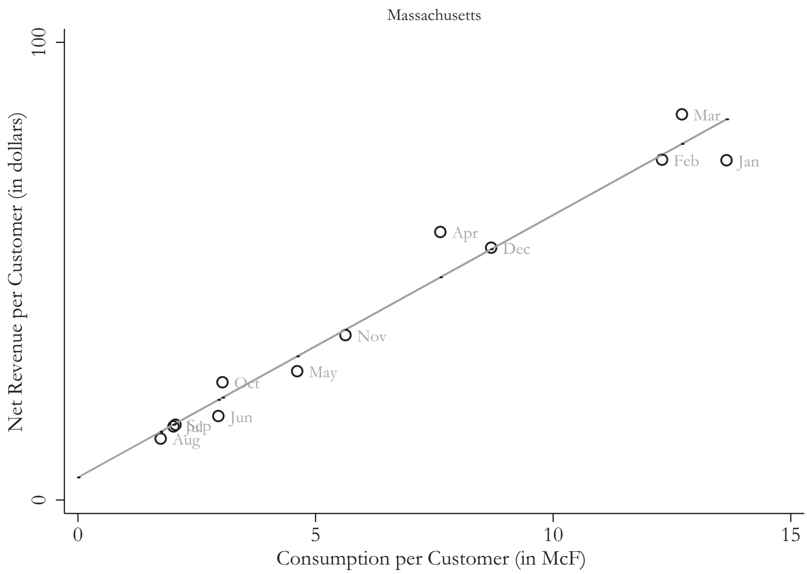
where monthly net revenue from residential sales per customer, NR_t, is regressed on monthly gas consumption per customer, q_t.

The variation in consumption during the course of the year traces the price schedule. The intercept, α_0 is the average amount paid in fixed monthly fees and the slope, α_1, is the average

[11] The largest deviation between EIA and Platts prices occurs in California in December 2000 following the El Paso pipeline explosion that severely curtailed natural gas shipments. The Platts city-gate price of \$25.61 per McF is substantially higher than the EIA city-gate price of \$8.75 per McF. We do not see the extremely high spot prices being passed through to consumers; average revenues from residential customers in California in December 2000 were \$12.56 per McF. The difference arises because the Platts price is based on spot transactions whereas the EIA price reflects the use of long-term contracts and other hedging strategies by the LDCs. Because of the substantial difference in this month, when conducting our test of marginal cost pricing, we drop the data for December 2000 in California.

FIGURE 1

RESIDENTIAL NATURAL GAS PRICE SCHEDULE FOR MASSACHUSETTS FOR 2006



per-unit markup over the city-gate price. The price schedule for Massachusetts in 2006 indicates that revenues tend to be collected from per-unit charges rather than from the fixed monthly fee. As a result, net revenue in winter months is many times higher than net revenue in summer months. For our test of marginal cost pricing we estimate equation (1), allowing α_0 and α_1 to vary by state, year, and customer class. The null hypothesis of marginal cost pricing is $\alpha_1 = 0$.

Table 2 presents the main results of our test of marginal cost pricing. Panel A reports F-statistics by state over all years and customer classes, panel B reports F-statistics by year over all states and customer classes, and panel C reports F-statistics by customer class over all states and years. For all 48 states (Alaska and Hawaii excluded), all years, and all three customer classes, we reject marginal cost pricing with p values less than 0.001. Overall, the tests provide strong evidence of departures from marginal cost pricing.[12] Our conclusions do not change if we use the alternative city-gate prices from EIA as our measure of marginal cost. Using this alternative measure of marginal cost, we reject marginal cost pricing for all 50 states, all years, and all customer classes.

Table 3 summarizes the per-unit markups borne by each customer class. On average, residential consumers paid a 47.9% per unit markup over the city-gate price, equivalent to a \$3.38 transportation fee per unit. The per unit markup for commercial customers is slightly lower, a 43.0% markup equivalent to a \$3.05 transportation fee per unit. Markups are much lower for industrial customers—industrial customers pay a 2.5% markup over the city-gate price on average, equivalent to a \$0.16 transportation fee per-unit. Overall, the results imply an average markup across all customer classes of 38.4%. Using the EIA city-gate prices, we find similar markups—we estimate that the average per-unit markup across all customer classes is 38.4%, equivalent to a \$2.70 per-unit markup. In the sections which follow we attempt to put these results in context, for example comparing our estimated markups to the increase that would be implied by proposed carbon legislation.

[12] In related work, Naughton (1982) tests the efficiency of price schedules for a sample of electric utilities in 1980. After estimating marginal costs using a translog cost function, Naughton finds that the per-unit prices faced by all customer classes exceed marginal costs.

TABLE 2 A Test of Marginal Cost Pricing in U.S. Natural Gas Distribution, 1991–2007

A. By State

	F-Statistic	(p Value)		F-Statistic	(p Value)
Alabama	57.7	(<.001)	Nebraska	49.8	(<.001)
Arizona	400.7	(<.001)	Nevada	201.1	(<.001)
Arkansas	97.6	(<.001)	New Hampshire	119.3	(<.001)
California	11.8	(<.001)	New Jersey	158.0	(<.001)
Colorado	12.2	(<.001)	New Mexico	17.2	(<.001)
Connecticut	228.5	(<.001)	New York	19.0	(<.001)
Delaware	77.3	(<.001)	North Carolina	73.6	(<.001)
Florida	12.4	(<.001)	North Dakota	15.5	(<.001)
Georgia	20.8	(<.001)	Ohio	27.6	(<.001)
Idaho	113.2	(<.001)	Oklahoma	40.8	(<.001)
Illinois	18.0	(<.001)	Oregon	11.7	(<.001)
Indiana	38.1	(<.001)	Pennsylvania	27.9	(<.001)
Iowa	36.1	(<.001)	Rhode Island	260.0	(<.001)
Kansas	46.2	(<.001)	South Carolina	62.7	(<.001)
Kentucky	38.1	(<.001)	South Dakota	23.1	(<.001)
Louisiana	14.9	(<.001)	Tennessee	45.1	(<.001)
Maine	76.7	(<.001)	Texas	13.9	(<.001)
Maryland	38.0	(<.001)	Utah	28.5	(<.001)
Massachusetts	53.7	(<.001)	Vermont	169.5	(<.001)
Michigan	9.2	(<.001)	Virginia	61.9	(<.001)
Minnesota	31.5	(<.001)	Washington	11.3	(<.001)
Mississippi	31.4	(<.001)	West Virginia	152.2	(<.001)
Missouri	58.7	(<.001)	Wisconsin	54.0	(<.001)
Montana	60.8	(<.001)	Wyoming	15.6	(<.001)

B. By Year

	F-Statistic	(p Value)		F-Statistic	(p Value)
Year 1991	285.4	(<.001)	Year 1992	143.4	(<.001)
Year 1993	313.5	(<.001)	Year 1994	150.3	(<.001)
Year 1995	88.2	(<.001)	Year 1996	5.1	(<.001)
Year 1997	77.4	(<.001)	Year 1998	199.6	(<.001)
Year 1999	147.8	(<.001)	Year 2000	1.8	(<.001)
Year 2001	9.0	(<.001)	Year 2002	48.0	(<.001)
Year 2003	5.0	(<.001)	Year 2004	15.4	(<.001)
Year 2005	9.4	(<.001)	Year 2006	82.6	(<.001)
Year 2007	37.6	(<.001)			

C. By Customer Class

All states, residential customers only	21.4	(<.001)
All states, commercial customers only	17.5	(<.001)
All states, industrial customers only	0.9	(=0.96)
All states, pooled	20.16	(<.001)

Note: For residential and commercial customers, these data describe the period 1991–2007. Consumption and price data for industrial customers are available for 2001–2007. The F-statistic for the tests by state are joint tests over all years and customer classes in a particular state. We dropped data for a particular state-class-year if more than six monthly observations are missing. For a typical state there are a total of 41 estimates of α_1 and the F-statistic is a joint test that α_1 is equal to zero for all customer classes and years. The F-statistic for the tests by customer class are joint tests over all states and years. There are 867 estimates of α_1 for the residential tests, 869 estimates of α for the commercial tests, and 350 estimates of α_1 for the industrial test. The pooled test is a joint test over 2,086 α_1 parameters. All F-statistics cluster by state. Knittel (2003) compares prices of electric and combination electric/natural gas utilities, finding evidence that the price markups of residential and commercial electricity consumers are used to subsidize industrial users of natural gas.

TABLE 3 Average Deliveries, Revenues, and Markups by Customer Class

	Fraction of Total Core LDC Deliveries	Fraction of Total LDC Net Revenues	Per-Unit Markup over City-Gate Price	
			Percent	Levels (per McF)
Residential customers	54.1%	71.1%	47.9%	$3.38
			(0.7%)	(0.04)
Commercial customers	27.3%	25.2%	43.0%	$3.05
			(0.7%)	(0.05)
Industrial customers	18.4%	3.7%	2.5%	$0.16
			(4.2%)	(0.27)
All customers, pooled	100.0%	100.0%	38.4%	$2.70
			(0.9%)	($0.05)

Note: The table reports averages across all available states for 2001–2007 for which data are available for all sectors, weighted by natural gas consumption in each state. Pooled markups are weighted by natural gas consumption for each customer class. Per-unit markups are normalized to year 2007 dollars. Deliveries to electric generators and noncore industrial and commercial customers are excluded. Standard errors in parentheses are block bootstrapped by state.

In addition to markups, Table 3 reports the fraction of total revenues collected from each customer class. The results indicate that residential consumers were responsible for 71.1% of total net revenues whereas receiving 54.1% of total core deliveries. In contrast, industrial customers were responsible for 3.7% of total net revenues whereas receiving 18.4% of total core deliveries. Although the pattern of revenues is interesting, these results should be interpreted with caution because it is not clear how these collected revenues compare to marginal customer costs. For example, the residential market is characterized by a large number of customers, each consuming a relatively small amount of natural gas. For each customer, the LDC must build and maintain an additional connection, purchase and maintain metering equipment, and process bills. Residential customers pay a large fraction of total revenue, but they also, therefore, impose a large fraction of total costs, and with the available evidence it is difficult to make strong statements about the net burden borne by different customer classes.[13]

□ **Total deadweight loss from nonmarginal cost pricing.** To evaluate the total deadweight loss from the observed departures from marginal cost pricing, we first estimate the elasticity of demand for each sector. We then calculate the deadweight loss associated with the current pricing schedules compared to marginal cost pricing.

For each customer class, we regress the log of monthly consumption per customer on the log of average natural gas prices, state*month-of-year fixed effects, and state*year fixed effects. The state*month-of-year fixed effects, allow for unique state-specific seasonal patterns in natural gas consumption, and state*year fixed effects allow demand in each state to change flexibly with long-run trends in income or housing growth. With state*month-of-year and state*year fixed effects, we estimate our coefficients off of deviations from mean seasonal patterns in each state. If long-run demand is more elastic, our estimate of the deadweight loss relative to marginal cost pricing would be conservative.

In addition, we include demand shifters appropriate for each customer class's use of natural gas. For the residential and commercial customers who use natural gas primarily for space heating, we include same-month demeaned heating and cooling degree days. Furthermore, we interact demeaned heating and cooling degree days with prices to allow the elasticity to vary with temperature. For industrial customers, who use natural gas for production, we omit heating and cooling degree days. Rather, we include the spot price of Brent crude oil in the demand equation, as some industrial customers have the ability to switch between fuel oil and natural gas. For all

[13] See Stigler (1971) and Peltzman (1976) for discussion of the Stigler-Peltzman theory of regulation that argues that regulators act to transfer wealth between interest groups.

TABLE 4 Demand Elasticity, by Customer Class

	Residential	Commercial	Industrial
Log(Delivered Price)	−0.278***	−0.205**	−0.709**
	(0.114)	(0.107)	(0.294)
Log(Price)*Heating Degree Days	0.274***	0.041	
	(0.037)	(0.049)	
Log(Price)*Cooling Degree Days	0.082	−0.049	
	(0.067)	(0.130)	
Log(Brent Crude Price)			0.333**
			(0.146)
Heating Degree Days (thousands)	0.166*	0.614***	
	(0.089)	(0.111)	
Cooling Degree Days (thousands)	−0.491**	−0.016	
	(0.202)	(0.283)	
Observations	11,619	11,607	4,147
R^2	0.986	0.973	0.994

Note: The first-stage F-statistics on the excluded instruments for delivered natural gas prices to residential, commercial, and industrial customers are 5.7, 7.2, and 22.6, all of which are significant at a p value less than 0.001. The first-stage F-statistics on the excluded instruments for the residential and commercial interaction terms with heating and cooling degree days are 145.2, 253.5, 119.7, and 350.9. Residential and commercial elasticities are estimated using data from 1989–2007. Industrial elasticities are estimated using data from 2001–2007. All specifications include state*month-of-year and state*year fixed effects. Standard errors are clustered by state. *, **, *** denote significance at the 90%, 95%, and 99% level, respectively.

TABLE 5 Estimates of Annual Deadweight Loss (in Millions), U.S. Natural Gas Distribution Market, 2001–2007

	Using Elasticities from Table 4	Setting All Elasticities = −0.2	Setting All Elasticities = −0.5
Residential customers	1297	968	2683
	(535)	(24)	(69)
Commercial customers	524	485	1354
	(241)	(18)	(54)
Industrial customers	897	189	543
	(492)	(19)	(55)
All customers, pooled	2719	1642	4580
	(771)	(34)	(101)

Note: For these estimates, we restrict the sample to years for which we have a balanced panel, 2001–2007. Results are similar using the entire samples 1991–2007. Standard errors are block bootstrapped by state with 1000 replications. For each bootstrap sample in column (1), we reestimate the price schedules and elasticities. For each bootstrap sample in columns (2) and (3), we reestimate the price schedules and take the elasticity as given.

three customer classes, we instrument for natural gas prices using heating and cooling degree days in all other states. For residential and commercial demand, we also use the Brent crude spot price as an instrument for natural gas prices.

We present our demand elasticity estimates in Table 4. We estimate that demand for natural gas in all three sectors is inelastic. The elasticity point estimates for residential, commercial, and industrial users are −0.278, −0.205, and −0.709, respectively. We estimate that the elasticity of residential customers is negatively correlated with heating degree days—residential consumers respond less to exogenous shifts in price during cold months. We estimate that a one-standard deviation increase in monthly heating degree days (419 degree days) increases the residential elasticity point estimate by 0.115. In addition, we find that the cross-price elasticity of industrial demand with respect to the crude oil price is 0.333.

Table 5 reports deadweight loss generated by using existing pricing tariffs relative to marginal cost prices. We separately report deadweight loss for each customer class as well as block bootstrapped standard errors.[14] In total, we estimate that the existing price schedules create \$2.7 billion annually in deadweight loss, relative to marginal cost pricing. In the United States, total expenditure on natural gas in 2008 by core customers was \$92 billion, so this represents approximately 3% of the total market.

These estimates provide a valuable preliminary assessment of the welfare consequences of the observed departures from marginal cost pricing. However, it is important to emphasize that the magnitude of the deadweight loss is sensitive to the elasticity of demand for natural gas. The estimates from Table 4 provide a starting point, but there is sampling variation in these estimates. Moreover, the relevant demand elasticity for these calculations is the long-run demand elasticity, which is likely to be larger than the short-run elasticity because agents may employ additional margins of adjustment. For example, in the long run, consumers may purchase new heating equipment and new appliances that use natural gas. Because the stock of equipment turns over slowly, the full long-run impact of a price change may not be realized for many years and estimating such long-run effects using historical data is extremely challenging. In order to assess sensitivity, Table 5 reports deadweight loss estimates for two alternative sets of demand elasticities. The magnitude of the implied deadweight loss varies predictably with the choice of elasticities, but even under the most conservative assumption ($-.20$ for all customers), total deadweight loss exceeds \$1.6 billion annually.

It is important to note that this is a partial equilibrium analysis and that these estimates of deadweight loss ignore any effects that a change in natural gas pricing would have on other markets. In our thought experiment, the price per unit of natural gas is decreased and set equal to marginal cost, whereas the monthly fixed fees are increased. This may lead some consumers to switch between natural gas and alternative energy sources such as electricity and oil. If prices for these other energy sources differ from marginal cost, these changes could have additional welfare consequences. A more comprehensive analysis would consider the complete set of available energy sources, the costs and pricing in all sectors, and model substitution patterns both across and within energy categories.

5. Discussion of possible explanations

■ The results in the previous section provide strong evidence of departure from marginal cost pricing in the U.S. natural gas distribution market. In this section, we consider several possible explanations for the observed rate structure, all of which likely play a role in distorting prices away from the theoretical ideal. We then discuss the implications of the current rate structure for carbon policy and other public efforts aimed at addressing the external costs of energy consumption.

□ **Profit maximization by LDCs.** One possible explanation for the current price schedules lies in the incentives created by rate-of-return regulation. As described in the previous section, the central idea behind rate-of-return regulation is that a firm's revenues must equal its costs so that economic profit is zero. In theory, the firm's allowed rate of return on capital investments should be set equal to the firm's market rate of return on capital for a riskless asset. In practice, however, the firm's market rate of return is imperfectly observed by regulators, who face a difficult tradeoff. If they set the allowed rate of return too low, the ability of the firm to raise capital can be threatened. If they set the allowed rate of return too high, this yields positive profits for the firm. Trying to balance these two objectives and under pressure from regulated firms, the conventional wisdom is that in practice allowed rates of return typically exceed the market rate.[15]

[14] When calculating the deadweight loss, we assume that the number of customers using natural gas does not change. If firms can accurately estimate consumer willingness to pay based on observable and nonmutable characteristics (e.g., heating/nonheating residential) and price discriminate on fixed fees, shifting to marginal cost pricing will create a welfare gain along the extensive margin as well. Consequently, our estimates likely understate the true deadweight loss.

[15] See, for example, Averch and Johnson (1962), Baumol and Klevorick (1970), and Joskow (1974).

When the allowed rate of return exceeds the market rate, the regulated firm has an incentive to maximize the rate base. As pointed out by Sherman and Visscher (1982), the price schedule that best allows the firm to increase the rate base depends on whether adding customers or increasing output requires marginally the most capital. For natural gas distribution, capital depends most importantly on the number of customers. More customers means more miles of network, more connections, more metering equipment, and so forth. Although a large number of potential rate structures satisfy the zero-profit condition, from the regulated firm's perspective the optimal rate structure is one with low fixed monthly fees that will induce as many customers as possible to enter the market.[16] Of course, low fixed fees also mean high per-unit charges. However, decreased consumption along the intensive margin is not costly from the regulated firm's perspective because the rate base does not depend on the level of natural gas consumption per customer. In short, under traditional rate-of-return regulation a regulated firm attempts to maximize the rate base, and this creates incentive for firms to lobby regulators for low fixed fees.

In adjusting per-unit charges and fixed monthly fees, the LDC faces a tradeoff between small and large customers. Small customers are sensitive to fixed fees, whereas large customers are sensitive to the price per unit. Consider, for example, a decrease in the fixed fee that is offset by an increase in the price per unit. Such a change attracts small customers whereas potentially leading some large consumers to switch to other energy sources. Whether or not such a change leads to a net increase or decrease in the number of customers depends on the distribution of customers of different sizes and the ease with which they can substitute across fuels. For the rate-base-maximizing explanation to make sense, it must be the case that the current price schedules with low fixed fees tend to increase the customer base relative to alternative schedules. There would seem to be some support for this. Particularly in the commercial and residential sectors, there are a large number of smaller customers who may indeed be sensitive to the fixed fee. Moreover, there tend to be fewer large customers, and the largest customers (e.g., noncore industrial and commercial customers) are typically able to negotiate alternative rate structures rather than switch to other energy sources.

From an efficiency standpoint, the important question in this context is how existing fixed fees compare to marginal connection costs. To add an additional customer requires connecting the customer to the central distribution network. This connection cost depends on the distance from the customer to the central network. In addition, LDCs incur costs installing and maintaining meters, processing bills, and providing customer service. Much of these additional costs should be considered marginal connection costs. Our study reveals very low fixed fees across states and customer classes. Thus, there would appear to be scope to improve efficiency by increasing fixed fees up to the level of marginal connection costs.

□ **Distributional considerations.** Distributional considerations provide an alternative and complementary explanation for the observed rate structure. With low fixed fees, the existing rates imply that within customer classes, high-demand customers pay a disproportionately large share of fixed costs. Where monthly fees are exactly zero, for example, a customer consuming 100 McF annually pays twice as much as a customer consuming 50 McF despite the fact that the cost of providing distribution service to these two customers is nearly identical. This structure may have progressive distributional consequences. If high-income households own large homes and consume high levels of natural gas, they will also pay a large share of total costs. This distributional argument is highlighted in a recent rate case for Bay State Gas before the Massachusetts Department of Telecommunications and Energy (emphasis added).

[16] These incentives could also help explain the fact that monthly fees sometimes vary within customer class. For example, some companies charge monthly fees for industrial customers that vary by historical consumption levels and some companies charge different monthly fees for residential customers depending on whether or not they use natural gas for heating. This price discrimination could be seen as a mechanism for inducing as many customers as possible into the market.

> The Attorney General also takes issue with the Company's proposed residential delivery rates (id. at 116-117). Whereas the Company's proposed block rates for the residential rate classes, the Attorney General requests that the Company provide a flat rate design (that is, no block charges) for the residential rate classes (id. at 117). The Attorney General argues that a flat rate design for the residential rate classes not only would simplify rate design but would also *provide lower bill impacts for all but those customers with higher than average use*.[17]

These distributional concerns make it politically difficult to implement rate changes that would increase fixed fees. Although state and federal programs exist aimed at providing assistance to low-income households with energy bills, there are concerns that these programs may not do enough for vulnerable populations.[18] Moreover, enrollment in means-tested subsidy programs is rarely high. As an example, Borenstein (2010) cites an upper bound of 78% for the take-up rate of the CARE program, a heavily promoted, means-tested electricity subsidy in California.

More broadly, fixed fees are salient to consumer protection groups, and they are perceived as substantially impacting energy bills for low-income groups and small businesses. Absent accompanying subsidies, lowering per-unit markups and increasing fixed fees would shift the burden of fixed costs from high-usage to low-usage customers. As Reiss and White (2005) find for electricity, nonlinear tariffs that increase the marginal price for high-usage customers may be preferable for distributional reasons. In addition, they estimate that high-income households are less price sensitive than low-income households, strengthening the distributional argument for nonlinear residential electricity tariffs. Although no previous work to our knowledge has performed a similar distributional analysis for natural gas demand or tariffs, many state boards cite distributional reasons when setting low monthly fees and high or increasing marginal prices.

□ **Environmental externalities.** Environmental externalities provide a third possible explanation for the observed departures from marginal cost pricing. Could it be the case that whether intended or unintended, the current system of price schedules serves to effectively internalize the external costs of energy? In this section we consider this possibility, but conclude that the markups are considerably higher than most available estimates in the literature for the external damages from natural gas consumption.

Section 4 showed that most customers face large per-unit charges for natural gas. The average customer markup (\$2.70 per McF) is equivalent to a tax of \$50 per metric ton of CO_2. Average markups vary substantially across customer classes, ranging from 2.5% for industrial customers to 47.9% for residential customers. For industrial customers, the average markup (\$0.16) is equivalent to a \$3 tax per metric ton of CO_2. In contrast, for residential and commercial customers, the average markups (\$3.38 and \$3.05, respectively) are equivalent to a tax of \$62 and \$56 per metric ton of CO_2. Interestingly, these markups straddle markups implied by the range of carbon taxes envisioned by most economists. For example, Nordhaus (2007) calculates a baseline optimal tax of \$10 and Metcalf (2007) calls for a \$15 tax. Regardless of one's views on the marginal external costs of CO_2 emissions, it is critical that carbon policy take into account preexisting distortions in the market. Based on \$10 or \$15 taxes, for example, the current per-unit price of natural gas for residential and commercial customers already exceeds marginal social costs.[19]

Given recent attention to the issue of climate change, it makes sense to consider the implications of current pricing schedules for carbon. However, it also makes sense to consider

[17] Massachusetts Department of Telecommunications and Energy, DTE 05-27, p. 325.

[18] The largest such program, the Low Income Home Energy Assistance Program, has been in operation since 1982 and operates in all 50 states with a \$4.5 billion dollar budget in 2009. Eligible households must meet income requirements and typically assistance is awarded on a first-come first-serve basis.

[19] In related work, Buchanan (1969), Barnett (1980), and Oates and Strassman (1984) consider Pigouvian taxes in the context of an unregulated monopoly.

TABLE 6 Estimates of Annual Deadweight Loss Accounting for Carbon Costs (in Millions), U.S. Natural Gas Distribution Market, 2001–2007

	Assuming Marginal Cost of Carbon of \$0 per Ton	Assuming Marginal Cost of Carbon of \$35 per Ton	Assuming Marginal Cost of Carbon of \$55 per Ton
Residential customers	1297	1197	1146
	(535)	(491)	(468)
Commercial customers	524	485	465
	(241)	(222)	(212)
Industrial customers	897	809	770
	(492)	(434)	(407)
All customers, pooled	2719	2491	2381
	(771)	(696)	(659)

Note: For these estimates, we restrict the sample to years for which we have a balanced panel, 2001–2007. Results are similar using the entire sample, 1991–2007. Standard errors are block bootstrapped by state with 1000 replications. For all cases, we use the estimated elasticities from Table 4 to calculate deadweight loss.

local pollutants such as nitrogen oxides and particulates.[20] Natural gas combustion releases .09 pounds of nitrogen oxides and .007 pounds of particulates per McF.[21] Using estimates from Muller and Mendelsohn (2009), the external costs of these emissions are less than 3 cents per McF, equivalent to a markup over average residential prices of about one fifth of 1%. Of course, marginal damages from local pollutants depend on the proximity between the location of emissions and population centers. However, even the 99th percentile estimates from Muller and Mendelsohn imply markups of less than 1% over average residential prices.[22] Thus, with neither carbon emissions nor with emissions of local pollutants would it appear that external costs justify the size of markups that are currently observed.

Nevertheless, the presence of external costs implies that the deadweight loss estimates in Table 5 may somewhat overstate the total welfare cost of the observed departures from marginal cost pricing. In Table 6, we present deadweight loss estimates that take into account that, due to external costs, the socially optimal level of natural gas consumption is lower than what would be implied by pricing at private marginal cost. We present results for three different values of the marginal cost of CO_2 emissions: \$0 per ton, \$10 per ton, and \$15 per ton. In each case, we use

[20] There may also be negative externalities from emerging forms of natural gas production. There is currently a great deal of excitement in the natural gas market about shale gas. Natural gas producers have long known that shale and other rock deposits contain large amounts of natural gas. It was not until recently, however, that horizontal drilling and hydraulic fracturing technology improved enough to make these supplies accessible at reasonably low cost. See, for example, D. Rotman, "Natural Gas Changes the Energy Map," *MIT Technology Review*, November 2009. See also "America's Natural Gas Revolution," *Wall Street Journal*, 11/3/2009 and "Has Natural Gas's Moment Come?," *Wall Street Journal*, 12/16/2009. These developments suggest that natural gas is going to continue to be an important part of the energy portfolio in the United States for many years to come. These technologies also, however, raise potential environmental concerns and in particular concerns about water consumption, although these potential costs are still poorly understood.

[21] U.S. Department of Energy, Energy Information Administration, "Natural Gas 1998: Issues and Trends," DOE-EIA-0560(1998), released April 1999, Chapter 2: Natural Gas and the Environment, Table 2. See also U.S. Department of Energy, Energy Information Administration, "Annual Energy Review," DOE/EIA-0384(2007), released June 2008, Table 12.7a. Natural gas is the cleanest of all major fossil fuels. Per unit of energy, natural gas combustion releases 80% less nitrogen oxides, 90% less particulates, and over 99% less sulfur dioxide and mercury than oil combustion.

[22] Muller and Mendelsohn (2009) use an integrated assessment model to track and value emissions from 10,000 point and aggregated nonpoint sources in the United States. Average marginal damages from Table 1 are \$1.61 per pound of particulates (PM2.5) and \$0.13 per pound of nitrogen oxides. The 99th percentile of marginal damages is \$6.20 per pound of particulates ($PM_{2.5}$) and \$0.55 per pound of nitrogen oxides. Alternative, and somewhat larger estimates of the marginal damages of nitrogen oxide emissions come from Muller, Tong, and Mendelsohn (2009) using the Community Multi-scale Air Quality model (CMAQ) rather than the reduced-form Air Pollution Emission Experiments and Policy (APEEP) model used in Muller and Mendelsohn (2009). With CMAQ, marginal damages from ground-level nitrogen oxide emissions from nine locations in and around Atlanta (Table 1) average \$0.27 per pound with a maximum of \$0.55.

our elasticity estimates from Table 4. As a point of reference, \$10 per ton of CO_2 is equivalent to a markup of \$0.54 per McF, and \$15/ton of CO_2 is equivalent to a markup of \$0.81 per McF. The first column is identical to the results reported in Table 5. Without incorporating the cost of CO_2 emissions, we estimate total deadweight losses of \$2.7 billion per year. Using a cost of \$10/ton of CO_2, our deadweight loss estimate falls to \$2.5 billion per year. Using a cost of \$15/ton of CO_2, our deadweight loss estimate falls further to \$2.4 billion per year.

Again, it is important to note that this analysis is partial equilibrium. In this thought experiment, the marginal price of natural gas is decreased and set equal to social marginal cost. We are ignoring the implications that this change would have for other markets. Lowering the marginal price of natural gas accompanied by an increase in the monthly fixed fees would affect demand for alternative energy sources such as electricity and oil. These changes could have additional welfare consequences if prices in these other markets differ from marginal cost. Moreover, these estimates of deadweight loss ignore externalities from the production, processing, transmission, storage, and distribution of natural gas. The U.S. Environmental Protection Agency (2010) reports that emissions from these sources in 2008 represented 9.3% of total greenhouse gas emissions from natural gas. Incorporating these additional external costs would modestly reduce the estimated total deadweight loss estimates in Tables 5 and 6.

6. Ownership structure and efficiency

■ There are several available approaches for addressing these departures from marginal cost pricing. There are many alternative rate structures which could improve efficiency whereas allowing LDCs to recoup their investments. In the conclusion we discuss rate "levelization," which would increase fixed fees whereas decreasing per-unit prices.

An alternative approach for lowering per-unit prices is public provision. Energy utilities in the United States operate under one of two types of institutional arrangements: (i) privately owned companies regulated by state public utility commissions, and (ii) publicly owned or "municipally owned" companies that are directly under public control. In both cases, the public sector controls rate setting. However, unlike privately owned companies which must recoup fixed costs from end users of natural gas, municipally owned companies can recoup fixed costs through government subsidies, thereby shifting the burden of fixed costs from natural gas consumers to taxpayers. Consequently, a municipally owned LDC may offer a price schedule with lower per-unit markups. Still, as we discuss in this section, the welfare effects of public provision are ambiguous because subsidies must be financed through distortionary taxes.

Municipal ownership is common in natural gas distribution. In 2007, approximately two thirds of LDCs were municipally owned (848 out of a total of 1229). On average, municipally owned LDCs are much smaller than investor-owned LDCs. In total, municipally owned LDCs delivered only 8% of the natural gas to end users in 2007. Despite differences in mean deliveries, the size distributions of municipally owned and investor-owned LDCs overlap substantially. Approximately 45% of municipal utilities and 34% of investor-owned utilities deliver between 100 million cubic feet of gas a year and 10 billion cubic feet of gas per year. Municipal utilities and investor-owned utilities are comparable on other observable dimensions. For the average municipally owned distribution company, 41%, 25%, and 33% of deliveries are made to residential, commercial, and industrial customers. In comparison, 42%, 26%, and 30% of deliveries of investor-owned utilities go to residential, commercial, and industrial customers.

To estimate the proportion of municipal utility fixed costs borne by taxpayers, we calculate annual net revenues for each distribution company using utility-level data from 1997 to 2007. In total, we observe 9426 company-years of municipal data and 3755 company-years of investor-owned data. In this case, we calculate net revenues for each LDC using the city-gate prices reported by the EIA rather than the Platts spot price data. The city-gate averages reported by the EIA measure the average natural gas procurement cost by state, including both spot transactions as well as long-term contracts. Thus, net revenues calculated using the

TABLE 7 Net Revenues of Municipally and Investor-Owned LDCs

	(1)	(2)	(3)	(4)
Log(Annual Deliveries)	0.873***	0.950***	0.805***	0.903***
	(0.009)	(0.009)	(0.026)	(0.024)
Municipally Owned	−0.314***	−0.265***	−0.310***	−0.251***
	(0.052)	(0.045)	(0.074)	(0.066)
Share of Deliveries		−1.347***		−1.200***
to Industrial Customers		(0.081)		(0.106)
Population Density		0.313		1.024*
		(0.389)		(0.614)
Full sample	X	X		
Mid-sized firms only			X	X
Observations	11,289	11,289	4,965	4,965
R^2	0.90	0.91	0.67	0.70

Note: All specifications include state fixed effects and year fixed effects. Standard errors are clustered by company. *, **, *** denote significance at the 90%, 95%, and 99% level, respectively.

EIA data provide the best proxy for the amount of fixed costs covered by the regulated price schedule.

We compare the net revenues earned by comparably sized municipally owned and investor-owned distribution companies. Table 7 presents the results from regressing annual net revenues for each firm on total deliveries (as a proxy for firm size), the proportion of deliveries made to industrial or electric customers (to account for differences in the composition of end users), population density, and a dummy variable corresponding to whether the distribution company is municipally owned. In each specification, we include state fixed effects and year fixed effects. Controlling for size and customer composition, we expect municipal utilities and investor-owned utilities to have similar fixed costs. Absent the ability of the government to fiscally subsidize a municipal utility, the firms should require similar net revenues. Specifications (1) and (2) include all firms, whereas specifications (3) and (4) restrict the sample to the portion of the firm size distribution where substantial overlap between municipally owned and investor-owned LDCs exists—between 100 million and 5 billion cubic feet of delivered gas per year. Restricting the sample to mid-sized distribution companies does not substantially affect the results. In all four regressions, we estimate a positive coefficient on annual deliveries between 0.805 and 0.950—in all cases, the estimates are statistically distinguishable from 1—consistent with a natural monopoly exhibiting economies of scale. We estimate that a 10 percentage point increase in the share of deliveries to large (industrial/electric) customers is associated with a 12%–13% reduction in net revenues. Finally, we estimate that, conditional on observables, municipally owned distribution companies collect approximately 25%–30% less net revenues through their service rates than investor-owned utilities. This is consistent with substantial direct subsidies to municipally owned LDCs that allow these LDCs to collect considerably less revenue from natural gas customers. Without monthly utility-level data it is impossible to say whether this comes in the form of lower markups or lower fixed fees (or both).[23]

The overall welfare impact of direct subsidies depends, therefore, on the marginal cost of public funds. Although subsidies increase the welfare of natural gas users, these gains are offset by tax distortions in other parts of the economy. As a thought exercise, we calculate the threshold

[23] An alternative explanation is that regulators allow investor owned or privately owned utilities to earn substantially higher profit than those earned by a municipally owned LDC. To check, we examined the 2007 annual reports of the six largest municipally owned LDCs. In 2007, the six municipally owned LDCs examined received direct and indirect subsidies. Subsidies took the form of government grants to cover operation, repairs and construction, access to subsidized government and cooperative natural gas supplies, and the ability to issue tax-exempt government bonds and commercial paper.

cost of public funds which lead a 25% subsidy of fixed costs to be welfare neutral. We estimate that a 25% subsidy of the per-unit transportation fee requires \$5.85 billion per year to cover lost revenues and is associated with a welfare gain of \$733 million to natural gas users. Consequently, the welfare-neutral threshold cost of public funds is roughly 12 cents per dollar. If a jurisdiction can collect taxes which introduce less than 12 cents of deadweight loss per dollar of revenue generated (and the cost of public versus private provision is similar), public subsidization of the fixed costs of operation may improve welfare if used to reduce per-unit markups.

Of course, there are other advantages and disadvantages of private ownership. A large literature in economics examines the effect of firm ownership on operating efficiency. See, for example, Olley and Pakes (1996), Joskow (1997), Ng and Seabright (2001), and Fabrizio, Rose, and Wolfram (2007). Privately owned LDCs typically have more incentive than publicly owned LDCs to reduce costs. Rate-of-return regulation guarantees privately owned LDCs, a certain rate of return on investments, but because of regulatory lag these firms have an incentive for cost reduction between rate cases. Moreover, managers of privately owned LDCs may be more motivated because of the threat that they would be replaced by a disappointed regulator, whereas management in publicly owned LDCs face less threat of takeover. On the other hand, effective regulation of privately owned LDCs is difficult because the regulatory agency needs detailed information about the firm's costs and the regulatory proceedings used to elicit this information require time and resources. In addition, regulation of privately owned LDCs may introduce additional inefficiencies such as overcapitalization (Averch and Johnson, 1962).

7. Concluding remarks

■ Our analysis of the U.S. natural gas distribution market supports the following conclusions. First, we strongly reject marginal cost pricing. This result holds individually and jointly for all 50 states, all 17 years, and for residential and commercial customer classes. Second, markups above marginal cost are largest for residential and commercial customers, averaging 47.9% and 45.0%, respectively. Markups for industrial customers are much lower, averaging only 2.5%. Third, for conservative estimates of the price elasticity of demand, these distortions impose large aggregate welfare losses compared to marginal cost pricing. In short, the current system with low fixed fees and high per-unit prices implies that there are too many natural gas customers, each consuming too little natural gas.

The most natural approach to addressing these departures from marginal cost pricing would be to have regulators work with LDCs to "levelize" rate structures, increasing monthly fees and lowering the price charged per unit. There is some precedent for this. For example, in May 2008 a new rate structure was approved for Duke Energy Ohio in which the monthly fixed delivery charge increased from \$4.50 to \$10.00 with an offsetting reduction in per-unit prices. The Public Utilities Commission of Ohio (PUCO) argued that the new "levelized" rate structure is more equitable, "making sure that each customer pays only their share of the costs Duke must cover to deliver gas to their home." According to PUCO, the costs of natural gas distribution including installing and maintaining pipelines, reading gas meters, processing bills, and taking customer service calls is the same "whether a customer uses a little natural gas each month, or a lot."

Carbon taxes could then be added to the "levelized" rates to ensure that customers pay the socially efficient price. Proceeding in this way would ensure that carbon policy works as it is designed. Levelized rates combined with a carbon tax or cap-and-trade program would make natural gas prices accurately reflect both private and social cost. If prices in other energy sectors also accurately reflect both private and social costs, this will encourage efficient choices across energy sources. Adding a carbon tax on top of the "levelized" rates would also create appropriate incentives for reducing carbon emissions from natural gas production, processing, transmission, storage, and distribution.

Natural gas is cleaner than other fossil fuels but less clean than energy from renewables, so some policymakers have argued that natural gas can serve as a bridge to a less carbon-intensive economy. Moreover, many industry observers believe that recent developments in horizontal drilling and hydraulic fracturing technology have ensured that natural gas will continue to play an important role in the United States' energy portfolio. It is crucial that natural gas be priced appropriately if these new sources are to be developed efficiently, and if energy consumers are to make efficient consumption and capital choices.

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