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Abstract

Technological innovations in horizontal drilling and hydraulic fracturing have enabled tremendous amounts of natural gas to be extracted profitably from underground shale formations that were long thought to be uneconomical. In this paper, we provide the first estimates of broad-scale welfare and distributional implications of this supply boom. We provide new estimates of supply and demand elasticities, which we use to estimate the drop in natural gas prices that is attributable to the supply expansion. We calculate large, positive welfare impacts for four broad sectors of gas consumption (residential, commercial, industrial, and electric power), and a negative impact for producers, with variation across regions. We then examine the evidence for a gas-led "manufacturing renaissance" and for pass-through to prices of products such as retail natural gas, retail electricity, and commodity chemicals. We conclude with a discussion of environmental externalities from unconventional natural gas, including limitations of the current regulatory environment. Overall, we find that the shale gas revolution has led to an increase in welfare for natural gas consumers and producers of $48 billion per year, but more data are needed on the extent and valuation of the environmental costs of shale gas production.

Following a decade of essentially no growth, natural gas production in the United States grew by more than 25 percent from 2007 to 2013. This supply boom, amounting to an increase of 5.5 trillion cubic feet per year, was driven by technological innovations in extraction. In particular, advances in horizontal drilling and hydraulic fracturing[1] have enabled natural gas to be extracted profitably from underground shale formations that were long thought to

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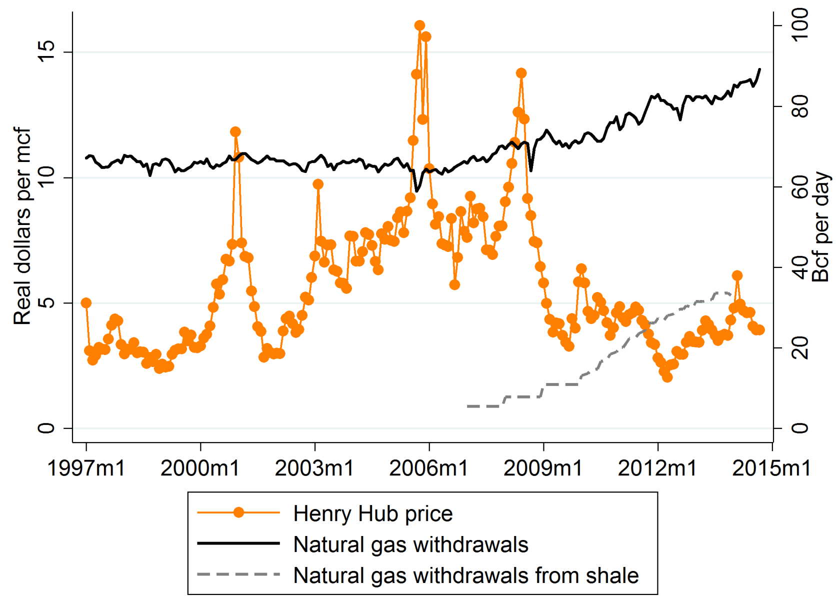
[1]The latter is often referred to as "fracking" or "fracing."

Figure 1: U.S. Natural Gas Production and Price



Note: Gross withdrawals includes not only marketed production, but also natural gas used to repressure wells, vented and flared gas, and nonhydrocarbon gases removed. Source: EIA.

be non-economic. Figure 1 shows this increase in total natural gas production, as well as the change in production from "unconventional" shale gas reservoirs. The increase in shale extraction began in the late 2000s, accelerated in 2010, and amounted to more than one trillion cubic feet per month by late 2013. As a result of this sustained growth in extraction, natural gas prices have fallen substantially in the U.S. Figure 1 plots the real[2] U.S. price of natural gas since 1997.[3] While prices averaged \$6.81 per mcf (2013 dollars per thousand cubic feet) from 2000 to 2010, prices since 2011 have averaged \$3.65 per mcf.

In this paper, we estimate the broad implications of this boom in unconventional natural gas for U.S. welfare. We examine effects on natural gas consumers and producers, paying particular attention to how benefits and costs are allocated across sectors and across space. We also discuss the potential environmental damages associated with fracking and how regulations might mitigate these externalities.

We begin in section 1 by providing background on natural gas markets, including the related literature on fracking. We then provide new estimates of supply and demand elasticities. In section 2, we use our estimated supply and demand functions to calculate the portion

[2]Prices throughout the paper are deflated to 2013 dollars using the CPI: all urban less energy.

[3]We focus on the Henry Hub price in Louisiana, the most liquid natural gas trading hub in the country. Prices are quoted in \$/mmBtu (dollars per million British thermal units), and we convert this to \$/mcf (dollars per thousand cubic feet). The heat content of natural gas varies, but the average conversion typically used is 1.025 mmBtu per mcf.

of the drop in natural gas prices that is attributable to the supply expansion, as opposed to simultaneous changes in the U.S. economy such as the recession and recovery. For 2007 to 2013, we estimate that the boom in U.S. natural gas production reduced gas prices by \$3.45 per mcf. We evaluate the impact of the supply shift and corresponding price change for consumers and producers in section 3. We show that consumer welfare increased by about 74 billion dollars per year from 2007 to 2013 because of the price fall. In contrast, producer surplus fell: wells, once drilled and producing, have very low marginal operating costs and are rarely idled—thus from 2007 to 2013, producers of existing wells lost \$30 billion per year in revenue from the price decrease. This loss was only partially offset by the gains associated with new wells, which totalled \$4 billion per year over this time period. Accordingly, we estimate that total welfare increased by \$48 billion per year, ignoring external costs from environmental damages (to which we return later in the paper). Under plausible alternative assumptions, this estimate varies by up to about 20 percent. This change in surplus is large relative to the size of the natural gas sector; retail spending on natural gas was around \$160 billion in 2013. On the scale of the economy as a whole, it is noticeable but not large—the change amounts to about 1/3 of 1 percent of GDP, or around \$150 per capita.

We also consider the distributional effects of the supply boom across sectors of the economy and across regions. Consumers of natural gas can be broadly separated into the residential, commercial, industrial, and electric power sectors. We calculate the breakdown in consumer surplus across these four sectors, finding the largest gains for the electric power and industrial sectors. We then estimate the distribution of consumer gains across states, finding that the largest gains are concentrated in the South Central and Midwestern United States, where industrial and electric power demand for gas is large. Regional variation in the producer surplus impact is substantial; shale-heavy states like Pennsylvania experienced net gains, whereas states with mostly conventional gas supplies lost. Finally, we examine the pass-through of natural gas wholesale price changes to end-users. We find that pass-through to retail natural gas prices is essentially 100%, implying that the consumer surplus gains we estimate have accrued to end-users of gas rather than distributors or retailers.

In section 4, we study how exports of liquified natural gas (LNG) would affect gas consumers and producers. Natural gas is costly to ship overseas: it must be liquified (by chilling to an extremely low temperature and placing under high pressure), then shipped on specialized LNG tankers, and then re-gasified at the final destination. A considerable wedge has developed since 2010 between relatively low U.S. natural gas prices and those in Europe and Asia, as shown in the left panel of figure 2. This price differential has led firms to apply to the U.S. government for LNG export permits. We use our modeling framework to simulate how the U.S. gas market would be affected by: (1) LNG exports equal to the capacity of all approved projects (9.2 bcf per day), and (2) LNG exports equal to the capacity of all approved and proposed projects (24.6 bcf per day). In both cases the U.S. natural gas price rises, leading to an increase in U.S. producer surplus, a decrease in U.S. consumer surplus, and a net gain overall. However, the net gain is limited (and nearly zero in the first case) because a share of the increase in overall producer surplus accrues to Canadian exporters of natural gas to the U.S.

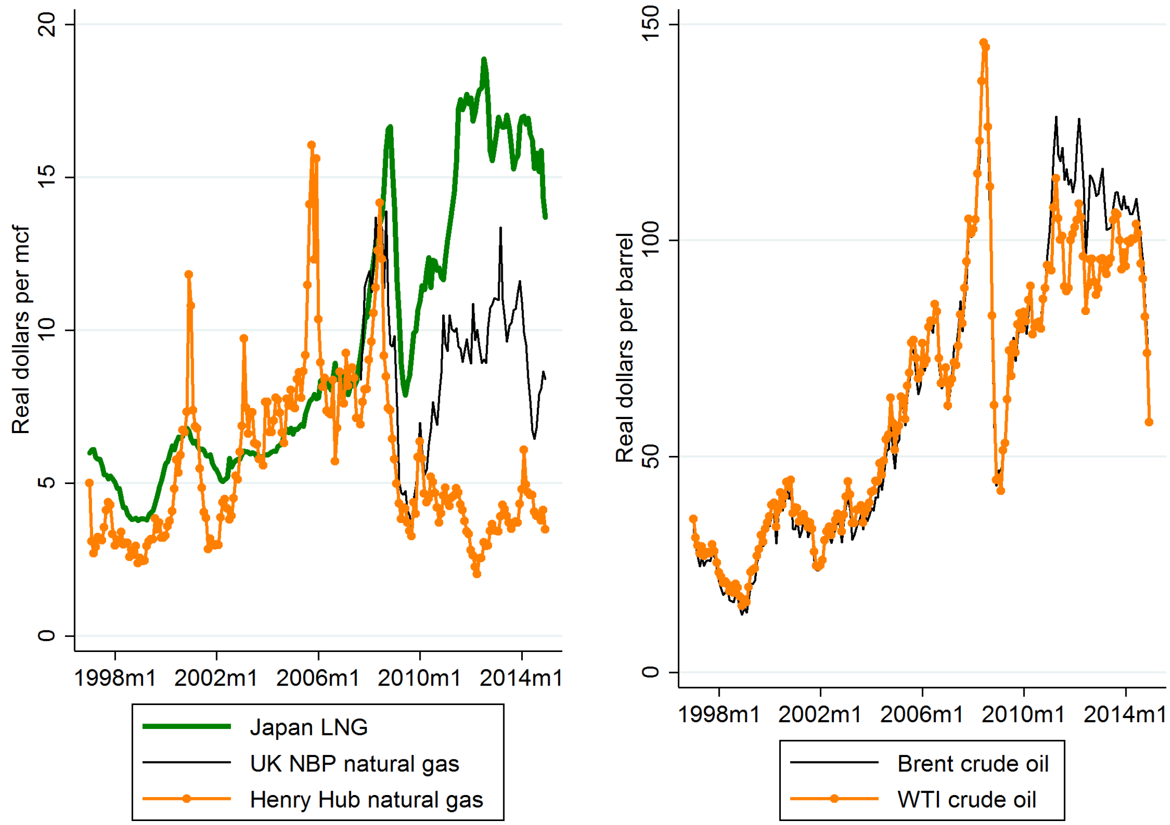
Section 5 considers the impacts of shale gas on manufacturing at a more disaggregated level, motivated by the considerable interest in whether shale gas will lead to a U.S. "manufacturing renaissance." We identify industries that are especially natural gas intensive in production and therefore have the potential to benefit the most from the shale boom. A handful of manufacturing sectors stand out as important, especially fertilizer production. We find that these sectors have grown more rapidly than other sectors over the course of the shale boom, though drawing a conclusive causal link is difficult. We document that the fertilizer industry has substantially expanded, likely owing to the fact that U.S. fertilizer prices are integrated with global markets and have therefore not greatly decreased. We find a similar pricing pattern for high-density polyethylene, a common plastic that uses natural gas as an input. Thus, at least for these gas-intensive chemical products, reductions in gas prices have not passed through to product prices.

Finally, there are important unpriced environmental impacts associated with shale gas production. Scientists have identified a long list of potential impacts, such as groundwater contamination and methane leaks. In section 6, we present the state of the literature on these impacts, noting in particular that data limitations prohibit valuation of the full environmental cost associated with shale gas extraction. We discuss the challenges associated with collecting data on these damages, as well as the implications of these data limitations for regulation of the industry.

While this paper focuses on natural gas, it is important to note that a shale oil fracking boom has been taking place alongside the boom in natural gas (see Kilian (2014*a*)). Oil production in the U.S. increased by almost 50 percent from 2007 to 2013, enabled by the same technological improvements driving the natural gas boom. Moreover, oil prices fell dramatically in 2014: from around $100 per barrel in Q1 and Q2 to around $50 per barrel by the start of 2015. We focus here on natural gas in part because it has historically received less attention in the literature.[4] Future work on recent changes to oil markets, driven by unconventional sources, would certainly be valuable. Natural gas and oil markets have some similarities (since they are both exhaustible resources, are substitute inputs for one another

[4] Excellent recent examples of work studying the link between oil and the macroeconomy include Hamilton (2009); Kilian (2009); Hamilton (2011); Kilian (2014*b*); Kilian and Murphy (2014).

Figure 2: U.S. and U.K. Natural Gas and Crude Oil Prices



Note: The Henry Hub price is an average of the daily NYMEX spot price. The UK price is an average of the daily National Balancing Point price, and it has been converted from GB pence per therm to dollars per mcf. Source: EIA for Henry Hub, WTI, and Brent spot prices; Bloomberg for the UK NBP spot price; World Bank for the Japanese LNG price.

in some industries, and are extracted using similar technologies), but they also have some key differences. In particular, crude oil is easily shipped internationally, so the world oil market is largely integrated.[5] In contrast, natural gas is easy to transport by pipeline but otherwise costly to ship. The shale oil boom has resulted in some transportation-related and grade-related bottlenecks, and therefore basis differentials between the U.S. and world oil prices (Borenstein and Kellogg, 2014; Brown et al., 2014; Kilian, 2014*a*). The right panel of figure 2 shows how the Brent (North Sea) price has increased relative to the U.S. West Texas Intermediate price since 2010. However, this oil price differential is small compared to the recent wedge in natural gas prices between North America and markets in Europe and Asia.

Overall, our study finds that a broad set of sectors has benefited from new sources of

[5]Though the U.S. remains a net importer of crude oil, the U.S. crude oil export ban binds due to crude quality differences. See Kilian (2014*a*) for a discussion.

unconventional natural gas. Households, for instance, have seen much lower utility bills for both natural gas and electricity. Industrial users have also benefited, including rents for some natural gas intensive industries that have not had to pass on the lower prices to their customers. Natural gas producers, on the other hand, have seen substantial revenue declines that have been only partially offset by the shale-driven expansion of drilling and production. The full scope of external environmental costs is still unknown, and better data are needed in this area.

1 Fundamentals of the U.S. Natural Gas Market

Natural gas marketed production in the United States was approximately 50 bcf per day for 1990 through 2007, primarily extracted from Texas, Louisiana, and Oklahoma.[6] From 2007 to 2013, production increased by 25 percent. This sharp acceleration of production was spurred by technological advances in horizontal drilling and hydraulic fracturing. While horizontal drilling and hydraulic fracturing have been in use for half a century, they only recently became cost-effective for large scale gas extraction. Reservoirs that have seen a lot of activity include the Barnett Shale in Texas and the Marcellus Shale in Pennsylvania.

Our paper relates to a nascent economics literature on the shale boom, including work that, like ours, devotes its attention to broad economic impacts. Fitzgerald (2013) offers a useful summary of stylized facts about the fracking boom, including summaries of the technological changes and their impact on the cost of extraction. Mason, Muehlenbachs and Olmstead (2014) provides a summary of the literature on shale gas in economics, as well as a broad first pass at calculating the scope of economic costs and benefits. Krupnick et al. (2014) summarizes policy questions that remain unanswered relating to economic impacts, environmental impacts, and preferred regulatory approaches. Other related work has used calibrated models of the energy sector to forecast future impacts of shale gas production (Brown and Krupnick, 2010; Krupnick, Wang and Wang, 2013), and a growing literature examines how falling natural gas prices affect electricity markets (Cullen and Mansur, 2014; Holladay and LaRiviere, 2014; Knittel, Metaxoglou and Trindade, 2014; Linn, Muehlenbachs and Wang, 2014). Local employment effects near extraction sites have been analyzed by Agerton et al. (2015), Allcott and Keniston (2014), DeLeire, Eliason and Timmins (2014), Maniloff and Mastromonaco (2014), and Paredes, Komarek and Loveridge (2015). In section 6, we summarize the large literature, spanning many disciplines, on the environmental

[6]While figure 1 plots gross withdrawals, we focus for the remainder of the paper on marketed production. Marketed production averages 80 to 85 percent of gross withdrawals, and does not include, for instance, reinjections. Figure 1 plots withdrawals, as marketed production specific to shale is not available.

impacts of fracking.

1.1 Demand and Supply Estimation: Empirical Strategy

Our paper is the first to provide a comprehensive analysis of the welfare impacts of the shale gas boom for consumers and producers, including the distribution of these impacts across consumption sectors and across space. An important first step in our analysis is the estimation of supply and demand functions for natural gas, and in particular the elasticities of supply and demand. These elasticities are essential inputs into the calculation of the U.S. natural gas price that would have held in 2013 had the shale gas revolution not expanded supply. Specifically, we will calculate the counterfactual equilibrium price of gas at the intersection of the 2007 supply curve with the 2013 demand curve; we need the elasticities of both supply and demand to identify this intersection relative to the realized 2007 and 2013 equilibria. With the counterfactual 2013 natural gas price in hand, we can then use the estimated supply and demand curves to estimate changes in producer and consumer surplus associated with fracking.

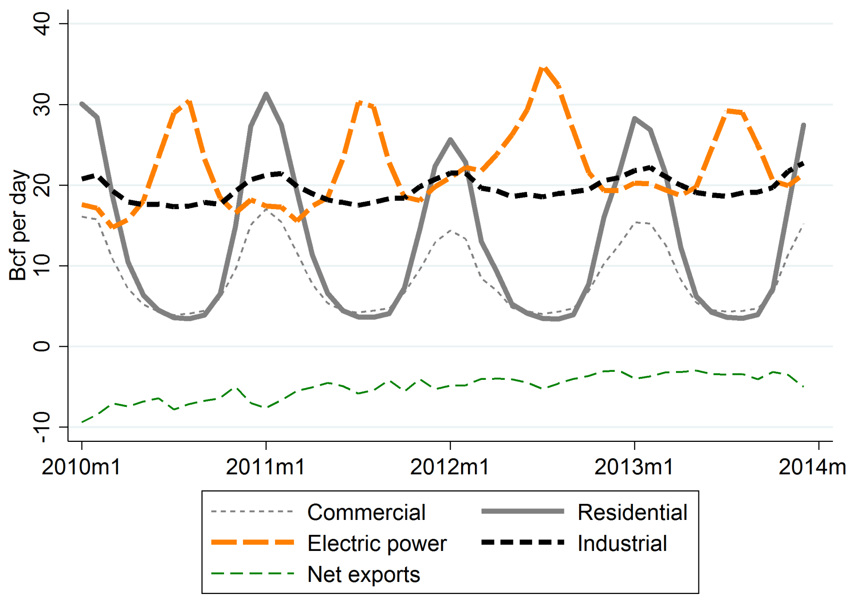
While some elasticity estimates exist in the literature (Davis and Muehlegger, 2010; Arora, 2014), they are not available for all sectors. We begin by estimating the short-run and long-run elasticities of natural gas demand. Consider a dynamic equation for natural gas consumption in state i in month t, C_{it}, in which adjustment costs lead to an AR(1) process:

$$\log C_{it} = \alpha_C \log P_{it} + \gamma_C \log C_{i,t-1} + \beta_C W_{Cit} + \mu_{Cit} + \delta_C t + \varepsilon_{Cit}. \tag{1}$$

In equation (1), gas consumption is affected by the current-period retail gas price P_{it}, observed weather W_{Cit}, state-specific seasonality μ_{Cit}, a secular trend, and a disturbance term ε_{Cit}, which includes unobservable shocks to energy-consuming economic activity. We model demand as a dynamic process because we anticipate that consumers' adjustments to price shocks will be gradual. For instance, consumers might react to high natural gas prices by making investments in energy efficiency; these investments usually require more than a single month to complete.

Because natural gas consumption and prices are simultaneously determined by the interaction of demand and supply, OLS estimation of equation (1) will be biased: the estimated magnitude of the demand elasticity α_C will be too low. To address this problem, we leverage the intuition from two previous papers that confront a similar issue. First, Davis and Muehlegger (2010) estimates a natural gas demand elasticity from state-level data using weather shocks in other states as an instrumental variable (IV). The intuition is that much of natural gas is used for space heating, so cold weather drives up demand and therefore price. To show the importance of space heating, figure 3 plots demand by month for each sector. The space heating impact leads to large seasonality for residential and commercial users; industrial demand also increases in the winter, but is much less seasonal. Natural gas usage in the electric power sector, in contrast, follows demand for electricity, and accordingly spikes in the summer.

Figure 3: U.S. Natural Gas Consumption



Note: This figure shows natural gas consumption for five major end uses. Natural gas used in vehicles, in drilling operations, and as fuel in natural gas processing plants are not shown, but all are small. Source: EIA.

The intuition for the validity of the Davis and Muehlegger (2010) instrument is that weather shocks in states other than i will be correlated with the natural gas price in state i because U.S. gas markets are well-integrated. At the same time, weather shocks in other states should not directly affect natural gas consumption in state i, after controlling for weather shocks in state i. To ensure that the instrument captures weather shocks and not seasonality, Davis and Muehlegger (2010) controls for state by month effects.

We do not rely solely on this approach, however, because we estimate a weak first stage. That is, after controlling for own weather, this is little variation left in other states' weather.[7] We therefore also take advantage of the theory of competitive storage, an approach that has been used in prior work to understand agricultural markets (Roberts and Schlenker, 2013). The intuition is that the price at which suppliers are willing to deliver gas is a function of the volume of gas in storage. Storage volumes at time t will be a function of shocks in

[7]Davis and Muehlegger (2010) also includes the Brent crude oil price as an additional IV. This instrument requires that demand shocks be uncorrelated across oil and natural gas markets.

previous periods; thus, lagged values of W_{Cit} are valid instruments for P_{it} in equation (1).[8] For instance, cold weather in month $t-k$ will drain gas storage reserves, increasing the gas price in periods $t-k$ through t (and beyond).[9]

We incorporate the intuition from both Davis and Muehlegger (2010) and Roberts and Schlenker (2013) by using lags of weather in states other than i as our instrumental variable. In practice, we operationalize W_{Cit} using heating degree days (HDDs), a measure of cold weather that is commonly used to approximate space heating requirements.[10] For each state-month observation it, we then construct the IV as follows: we calculate population-weighted average HDDs for each month for all states in other regions (defined as census divisions) and then sum these averages over lags two through twelve. We sum across lags two through twelve for two reasons. First, the effect of weather on storage is cumulative; prices will likely increase more when draw-downs have already occurred. Second, we want the second-stage to be identified off of price variation in all months, not only months with cold weather. Otherwise, our estimated elasticity would only be appropriate for winter months.

We control for current weather (as measured by heating and cooling degree days), one-month lagged weather, state by month effects, and a linear time trend. Since we identify off of variation in weather shocks, the linear time trend is not necessary for unbiased estimates, but it does aid with precision. Conditional on these controls, we thus make fairly weak assumptions to obtain identification: the exclusion restriction is satisfied as long as two-month through twelve-month lagged weather shocks in other regions are conditionally uncorrelated with demand. For this to be satisfied, we simply need any impact of past weather on current consumption to be picked up in the AR(1) term. Standard errors are two-way clustered by sample month and state.

Our strategy for estimating the natural gas supply elasticity is conceptually very similar to that for demand. We again use the behavior of storage to motivate our instrument – in fact, the same instrument can be used for the supply equation. Conceptually, anything that drives down storage volumes in previous months will increase price in the current month, impacting both current supply and demand. Since storage volumes can fluctuate, supply need not equal demand in any given month; thus the same instrument can be used for both equations. In practice, there are a few operational differences in how we implement this idea.

[8] Lagged prices and consumption may potentially also be valid instruments; however, the validity of these IVs requires no serial correlation in ε_{Ct}.

[9] We verified this empirically by regressing inventories (in levels or changes) on cold weather, controlling for month effects. We estimate negative and statistically significant effects of cold weather, lasting for around six to eight months.

[10] On any given day, the number of heating degrees is given by $min(0, 65-T)$, where T is the day's temperature in degrees Fahrenheit. We then average across days in the month. Cooling degree days (CDDs) are analogous to heating degree days, and are given by $min(0, T-65)$.

First, we use national rather than state-level totals, because of data limitations. Second, we use the wholesale Henry Hub natural gas price rather than retail natural gas prices; results are similar if we use the wellhead price instead of Henry Hub. Third, we found that power in the first stage was aided by using one-month lagged HDDs and CDDs, rather than cumulative HDDs.

Rather than use natural gas production in month t as the dependent variable, we use the number of wells drilled in month t.[11] We do so because oil and gas producers respond to price shocks not by changing the production rate of existing wells but by changing the rate at which they drill new wells (Anderson, Kellogg and Salant, 2014).[12] Thus, the supply equation we estimate is given by:

$$\log S_t = \alpha_S \log P_t + \gamma_S \log S_{t-1} + \beta_S W_{St} + \mu_{St} + \delta_S t + \varepsilon_{St}. \tag{2}$$

where S_t is the numbers of wells drilled.[13] We again control for month effects to isolate weather shocks from seasonality, and we include a linear time trend for precision. We also control for current weather because it may be correlated with our instrument (past weather), and it may impact current drilling operations. Standard errors are HAC robust.

Our data source for consumption and retail prices is the Energy Information Administration (EIA). The data are at the monthly, state level for 2001 to present, and they are broken down into residential, commercial, electricity sector, and other industrial usage.[14] Because the electric sector price has many missing values, our preferred electric power specification uses the citygate price, also available from the EIA.[15] Our data source for monthly natural gas production and the number of wells drilled is also the EIA. The drilling data, which we use for the elasticity estimation, are monthly but unfortunately are not available at the state

[11] Appendix figure A1 shows a time series of natural gas wells.

[12] Moreover, in the drilling and production model of Anderson, Kellogg and Salant (2014), the long-run drilling elasticity equals the long-run production elasticity, assuming that resource scarcity rents are small, because steady-state production is proportional to steady-state drilling. A few caveats are necessary here. First, we are assuming that productivity from wells drilled when prices are high is the same as productivity from wells drilled when prices are low. Second, the time horizon at which the elasticities are equal may be longer than the period we consider. Finally, some natural gas is extracted from oil wells, which likely have a lower elasticity with respect to natural gas prices. Below, we consider bounding cases on the price and welfare impacts using both a higher and lower elasticity.

[13] More specifically, the data track wells drilled and "completed" – i.e., ready for production.

[14] Total consumption is available farther back, but electricity and industrial consumption data only begin in 2001. For consistency across sectors, we use 2001 through 2013. The demand regressions do not include Alaska, DC, or Hawaii. Additionally, some of the electricity sector usage data are "withheld to avoid disclosure of individual company data." These are from states with low levels of usage. Also, some states report zero electricity sector usage for some months; we replace with ln(0.1), but results are similar if we drop these observations.

[15] The two prices are highly correlated, and results are similar if we use the electric power price instead.

level, and recent years (2011-2014) have not yet been released. For production, we focus on marketed production rather than gross withdrawals, as the latter includes gas reinjected into wells. Marketed production is available for a few states with substantial production (such as Texas, Louisiana, and Oklahoma), while other states are aggregated together. In the supply estimation, we use average monthly spot prices from Bloomberg. We focus on the price at Henry Hub, Louisiana, which is the delivery point for liquidly traded natural gas spot and futures contracts. Henry Hub is also typically well-integrated with other U.S. natural gas markets. Finally, we use monthly state-level weather data (heating and cooling degree days) from the National Climatic Data Center at the National Oceanic and Atmospheric Administration.

1.2 Elasticity Estimation Results

Our primary natural gas demand and supply estimates are presented in table 1 below. The demand elasticity varies by sector, although the differences are not statistically significant. The industrial and electric power sectors are most elastic, with short-run price elasticities of -0.16 and -0.15, respectively. The long-run elasticities, equal to $\alpha_C/(1-\gamma_C)$, are -0.57 and -0.47. The residential and commercial sectors have short-run elasticities of -0.11 and -0.09, respectively, with long-run elasticities of -0.20 and -0.23.[16] The estimated short-run supply elasticity, α_S, is 0.09, with a standard error of 0.05. The long-run elasticity is 0.81.

Unfortunately, the estimates are imprecise for supply and for all demand sectors. Conceptually, this is not surprising. Our identifying variation comes largely from movements in prices in response to national weather shocks, so the specifications are akin to time-series regressions using eleven years of monthly data for demand and nine years of monthly data for supply.[17] In the appendix (tables A4, A5, A6, and A7) we consider a number of additional robustness checks, including alternative instruments (such as shorter and longer weather lags, and regional weather) and alternative controls. It is reassuring that the results, in particular the long-run elasticities, are generally very similar using these alternative specifications. Our short-run elasticities are smaller than those from Davis and Muehlegger (2010), which reports an average short-run elasticity of -0.28 for residential, -0.21 for commercial, and -0.71 for industrial users. Arora (2014) estimates a long-run residential demand elasticity of -0.24, and a long-run supply elasticity ranging from 0.10 to 0.42.

Appendix tables A2 and A3 provide first stage estimates for the demand and supply

[16]Summing across the four sectors, the demand equation no longer has constant elasticity. For the range of quantities observed in our data, the long-run elasticity of total demand is -0.4.

[17]Conventional rather than clustered standard errors, as a result, would have been only about half as large for the demand equations. For the supply equation, conventional standard errors are slightly larger than the HAC-robust results we report.

Table 1: Demand and Suppy Elasticity Estimates

	Demand				Supply
	Residential	Commercial	Industrial	Electric power	Drilling
log(Price)	-0.11	-0.09	-0.16	-0.15	0.09
	(0.11)	(0.08)	(0.07)	(0.14)	(0.05)
y_{t-1}	0.43	0.59	0.72	0.68	0.89
	(0.05)	(0.04)	(0.09)	(0.03)	(0.04)
Heating degree days, hundreds	2.94	2.29	0.58	1.35	-1.02
	(0.23)	(0.18)	(0.12)	(0.48)	(0.33)
Cooling degree days, hundreds	-1.07	-0.48	-0.21	10.92	-0.72
	(0.19)	(0.17)	(0.22)	(1.36)	(0.68)
Implied long-run price elasticity	-0.20	-0.23	-0.57	-0.47	0.81
	(0.19)	(0.18)	(0.17)	(0.43)	(0.16)
First-stage F	10.01	10.55	10.33	11.85	4.46
Observations	6912	6912	6912	6849	108

Note: This table reports 2SLS price elasticity estimates for U.S. natural gas supply and demand. The dependent variable is quantity in logs. Tables A2 and A3 in the appendix show the first stage estimates. The instrument in the demand equations is cumulative lagged weather (heating degree days) in other census divisions. As described in the text, the instrument is constructed with lags 2 through 12. The instruments in the supply equation are one-month lagged national HDDs and CDDs. The time period covered is 2002-2010 for supply and 2002-2013 for demand. The supply equations use national time-series data; the demand equations use a national panel. All specifications include month effects and a linear time trend; the demand equations also include state by month fixed effects and one-month lagged cooling and heating degree days. Standard errors are HAC robust for supply and are two-way clustered by sample month and state for demand.

specifications in table 1. For all four demand sectors, the instrument—cumulative lagged HDDs in other states—has a positive and statistically significant effect on the natural gas price, as expected. For supply, the instruments—lagged national HDDs and CDDs—also have a positive effect on the natural gas price.

2 How Much Has the Natural Gas Boom Lowered U.S. Prices?

The goal of this section is to assess the extent to which the shale gas boom has reduced the price of natural gas in the United States. We study changes in prices and production beginning in 2007, when shale gas began to compose a substantial share of total U.S. gas production. From 2007 to 2013, the Henry Hub price fell in real terms from $8.00 per mcf to $3.82 per mcf, as shale gas withdrawals rose from 5 bcf per day to 33 bcf per day. However, the raw price difference of \$4.18 per mcf may not be the causal impact of the shale boom on gas prices, because natural gas demand was likely not constant over this time period. We therefore seek to estimate the *counterfactual* gas price that would have held in 2013—given 2013 demand—had natural gas supply not expanded.

Calculating the counterfactual 2013 gas price requires estimates of the demand and supply curves for natural gas. We assume that supply and the four sectors of demand are constant elasticity over the range of the data, with elasticities given by the estimates from section 1.2 above. We assume that the elasticities have not changed from 2007 to 2013; we do not have enough statistical power to investigate this assumption in our data. We back out the scale parameters for the demand and supply curves for each year using observed Henry Hub prices, average mark-ups, and observed quantities. Specifically, to sum demand across sectors, we must make assumptions on how Henry Hub prices pass through to each sector's retail price. We expect one-to-one pass-through in the long run due to rate-of-return regulations; below we verify this empirically. We additionally assume a constant mark-up in each sector, equal to the average mark-up observed over the period 2007 to 2013. The resulting demand function for each year y in 2007 and 2013 is:

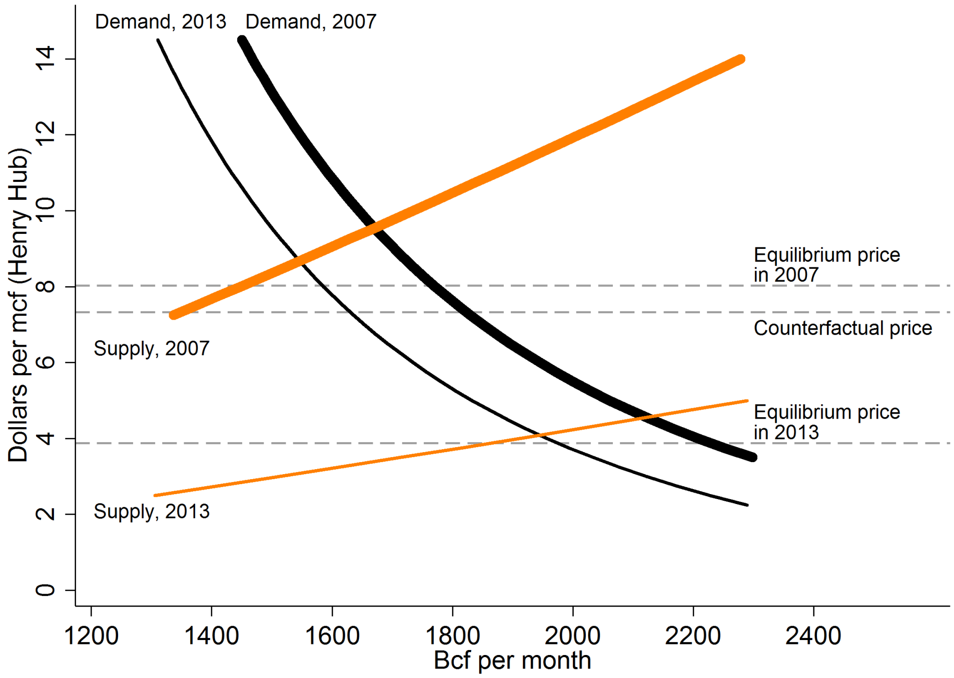
$$Q_{C,y} = \sum_{i \in (\mathrm{r,c,i,e})} A_{Ciy} \cdot (P_{HenryHub} + \text{mark-up}_i)^{\eta_i}$$

where the four sectors are residential, commercial, industrial and electric power, η is the sector-specific price elasticity, and the scale parameters A_{Ciy} have been calculated using observed prices and quantities in each year. Similarly, the supply function is:

$$Q_{S,y} = A_{Sy} \cdot (P_{HenryHub})^{\eta_S}$$

Figure 4 shows the resulting supply and demand functions for 2007 and 2013. The thick lines show 2007, and thin lines 2013. The supply boom can be clearly seen in this figure, as expected. Interestingly, the demand elasticites we estimate lead to scale parameters that imply an inward shift in demand from 2007 to 2013. In appendix figure A2, we show the demand shift for each of the four sectors, finding that the inward shift is driven largely by the industrial and electricity sectors. These shifts are plausible, as manufacturing has decreased, and as there has been a secular reduction in electricity generated by fossil fuels. Table A1 in the appendix summarizes potential demand shifters. While GDP and population both increased from 2007 to 2013, median income decreased, potentially affecting residential heating demand, and electricity generation from fossil fuels decreased substantially (driven by both a drop in total electricity quantity as well as an expansion of renewables). Moreover,

Figure 4: Supply and Demand in the U.S. Natural Gas Market



Note: The thick lines show 2007, and thin lines 2013. The equilibrium prices are not at the intersection of domestic supply and demand, since there are non-zero net imports. For 2007 and 2013 net imports, we use the quantities observed in our data. For the counterfactual scenario, we assume a linear net import function, as described in the text.

employment and establishment counts for non-gas-intensive manufacturing industries have substantially fallen (we present the trends for non-gas-intensive industries to separate secular changes from the impacts of the gas price fall).

To calculate equilibrium prices and quantities in the counterfactual scenario, two other assumptions are additionally necessary. First, we assume that the portion of supply used for pipeline operations and drilling operations is constant across time, as is the ratio of wet to dry gas. Second, the equilibrium prices are not at the intersection of domestic supply and demand, since there are non-zero net imports. The vast majority of natural gas trade is with Canada and Mexico by pipeline; as described below, liquified natural gas trade with other countries remains extremely small. For 2007 and 2013 net imports, we use the quantities observed in our data. For the counterfactual scenario, we must make assumptions about the behavior of imports and exports. We assume that the net import function (driven largely by the Canadian and Mexican supply and demand functions) did not change from 2007 to 2013,[18] and we fit a linear function through the observed prices and quantities in 2007 and 2013. This net import function allows us to calculate net imports at the counterfactual

[18]While shale gas is being extracted in Canada, it has not yet proved as significant as in the U.S.

Table 2: Natural Gas Price Decrease and Changes in Consumer and Producer Surplus Associated with Shale Gas

		Alternative elasticities				Alt. decline rates	
	Base case	Low 1	Low 2	High 1	High 2	Low 3	High 3
Counterfactual price decrease, $ per mcf	3.45	2.19	3.06	4.12	4.16	3.45	3.45
Change in consumer surplus, $billion per year	74	45	60	92	93	74	74
Residential	17	10	14	20	20	17	17
Commercial	11	7	9	13	13	11	11
Industrial	22	13	17	28	28	22	22
Electric power	25	15	20	31	31	25	25
Change in producer surplus, $billion per year	-26	-8	-20	-40	-37	-36	-19
Change in total surplus, $billion per year	48	37	41	52	56	37	55

Note: The left-most column represents the base case, with elasticities as estimated in the text. In "Low 1," the demand elasticities are doubled, and the supply elasticity is halved. In "Low 2" all elasticities are doubled. In "High 1" all elasticities are halved. In "High 2" the demand elasticities are halved and the supply elasticity doubled. In "Low 3" the decline rate is halved; in "High 3" the decline rate is doubled.

price.[19]

For the resulting supply, demand, and net imports functions, we calculate equilibrium prices and quantities for 2007 and 2013. The resulting prices are $8.03 per mcf for 2007 and $3.88 per mcf for 2013.[20] The equilibrium 2013 price that would have resulted from the demand shift, had supply not expanded, is $7.33 per mcf. Thus we estimate that the natural gas supply expansion from 2007 to 2013 lowered wholesale prices by $3.45 per mcf.

Given the imprecision of the supply and demand elasticities, it is important to consider bounds on this price decrease. In table 2, we show the estimated price decrease for alternative assumptions on the elasticities. The cases we consider assume a halving or a doubling of all the elasticities. For demand, then, the alternative long-run price elasticity is either -0.10 or -0.40 for residential use; -0.12 or -0.46 for commercial; -0.29 or -1.14 for industrial; and -0.24 or -0.94 for electric power. For supply, the long-run price elasticity can take on a value of 0.41 or 1.62. The counterfactual price change for these alternative assumptions ranges from a decrease of $2.19 to a decrease of $4.16.

[19]Alternatively, we can assume that the elasticity of net exports is determined by the difference between supply and demand elasticities in other countries. We assumed the same elasticities we observe for the U.S. (a plausible assumption for Canada and Mexico) and fit linear net export equations for 2007 and 2013 accordingly. Equilibrium prices and quantities in the counterfactual scenario are similar using this method to what we report in the text.

[20]For comparison, the observed prices in our data are $8.00 and $3.82, respectively. The difference arises from our assumption that mark-ups are constant over time within each sector.

3 Welfare Impacts of the Gas Supply Boom

3.1 Consumers of Natural Gas

In this section, we use our supply and demand functions to estimate the changes in consumer and producer surplus caused by the natural gas supply boom. For consumer surplus, we calculate in figure 4 the area bounded by the counterfactual pre-period price ($7.33 per mcf), the post-period observed price ($3.88 per mcf), the y-axis, and the 2013 demand curve. This area, the change in benefits accruing to consumers as a result of the price decline and quantity expansion from 2007 to 2013, totals almost $75 billion per year. The left-most column in table 2 shows the portion accruing to each sector. The electric power sector, which in 2013 consumed the largest amount of natural gas, experienced the greatest benefit from the price decline, with an increase in consumer surplus of around $25 billion. Consumer surplus in the industrial sector increased by around $22 billion, residential by $17 billion, and commercial by $11 billion per year.

The welfare results are a function of the elasticities we use in our calculations. Table 2 shows welfare measures for four alternative cases, corresponding to the alternative assumptions on price elasticities described in section 2. The total increase in consumer surplus ranges from a low of $45 billion per year to a high of $93 billion.[21]

Table 3 breaks out the change in consumer surplus by region. We calculate each region's change in consumer surplus using our counterfactual price change and each Census division's sectoral counterfactual quantity change.[22] For ease of comparison across divisions, we divide by the population in 2013. It is important to note that these calculations do not account for spillovers across regions. For instance, some of the electric power produced in one state is consumed in other states. Similarly, benefits in the industrial sector could be accruing to out-of-state consumers and shareholders as opposed to in-state employees. Nevertheless, we believe this is a useful first pass at disaggregating benefits by region, and some results in particular are worth highlighting.

Ex-ante, one might have predicted that the bulk of the benefits would accrue to cold weather states that use a lot of natural gas for space heating. In fact, however, the region with the greatest impact by far is West South Central, comprised of Arkansas, Louisiana,

[21] This range is qualitatively similar to the calculation done by Mason, Muehlenbachs and Olmstead (2014). Under an assumed elasticity of -0.5 for overall demand, they calculate a change in consumer surplus of $65 billion per year.

[22] We also explored allowing price elasticities to vary by region. The residential elasticity, for instance, might vary according to how much demand is used for space heating as opposed to cooking. Similarly, the electric power elasticity might vary by how much of electric capacity is coal-fired plants versus natural gas. The resulting elasticity estimates were noisy, as expected. Reassuringly, the consumer surplus estimates were qualitatively similar to those presented in table 3.

Table 3: Regional Impact on Consumers

	Change in 2013 consumer surplus, before spillovers, Dollars per year per person				
Census division	Residential	Commercial	Industrial	Electric power	Total, All sectors
New England	50	39	26	75	190
Middle Atlantic	71	50	24	76	220
East North Central	99	53	77	30	259
West North Central	73	51	94	20	237
South Atlantic	25	21	29	92	167
East South Central	33	24	81	101	239
West South Central	31	26	212	163	432
Mountain	57	35	34	83	209
Pacific	42	23	54	62	181

Note: For all four sectors, the counterfactual price change is a fall of $3.45 per mcf, as described in the previous section. New England includes CT, MA, ME, NH, RI, and VT. Middle Atlantic includes NJ, NY, and PA. East North Central includes IL, IN, MI, OH, and WI. West North Central includes IA, KS, MN, MO, ND, NE, and SD. South Atlantic includes DC, DE, FL, GA, MD, NC, SC, VA, and WV. East South Central includes AL, KY, MS, and TN. West South Central includes AR, LA, OK, and TX. Mountain includes AZ, CO, ID, MT, NM, NV, UT, and WY. Pacific includes CA, OR, and WA.

Oklahoma, and Texas. This result is driven by the impact on the industrial and electric power sectors, both of which used substantial amounts of natural gas over this time period. The region with the second largest change is East North Central, comprised of Illinois, Indiana, Michigan, Ohio, and Wisconsin; there the result is driven by both residential and industrial impacts.

More generally, the "consumers" definition of these sectors aggregates across many economic agents. The benefits for the residential sector, for instance, could in principle accrue to either utilities providing natural gas or households who heat with natural gas. Similarly, the commercial and industrial sectors include both companies (employees and shareholders) and the purchasers of their products. Finally, the benefits for the electric power could be accruing to electric power companies, households consuming electric power, commercial and industrial users of power, or the consumers of goods those companies produce. We next separate out some of these agents, considering pass-through to retail natural gas and electric power prices, and we will later also consider pass-through to some finished manufacturing products.

3.2 Pass-Through to Product Prices

Next we explore how the benefits to consumers accrue to households versus industries. We first note that providers of natural gas are generally regulated with average cost, or rate-of-return, regulations. As such, we expect the long-run pass-through of wholesale natural gas prices to retail natural gas prices to be one-to-one (in levels), although the adjustment may be slow depending on the structure of the price regulations. We verify this one-to-one pass-through empirically for all four demand sectors, using the same data we used for the elasticity estimation. Panel A of table 4 shows results from estimation of the following regression for pass-through of the wholesale Henry Hub price to sector-level retail prices:

$$\log P_{it}^{retail} = \sum_{l=0}^{11} \alpha_l \log P_{t-l}^{HenryHub} + \gamma \log P_{i,t-1}^{retail} + \beta W_{Pt} + \mu_{Pit} + \delta_{Pt} + \varepsilon_{Pst} \tag{3}$$

Because pass-through is unlikely to be immediate, we include a lagged dependent variable and several lags of the Henry Hub price in the regression. We also include controls for weather W_{Pt}, state-by-month-of-year effects μ_{Pt}, and year effects δ_{Pt}. As shown in panel A of table 4, we cannot reject long-run one-to-one pass-through for any of the four sectors (estimates of individual coefficients on the price regressors are given in the appendix). This result matches our intuition regarding price regulation.

Panel B of table 4 presents a 2SLS specification that instruments for the Henry Hub price with lagged weather (HDDs and CDDs). Power issues in the first stage preclude us from using multiple lags of the Henry Hub price as explanatory variables; instead we use only the contemporaneous Henry Hub price. The intuition for why OLS may be biased is as follows: a positive shock to retail prices will drive down quantity consumed, which in turn will drive down the Henry Hub price. This issue should only be qualitatively important if shocks to retail prices are correlated across states, and in practice the OLS and 2SLS results are similar. Overall, with one-to-one pass-through, we expect that local natural gas distribution companies have not benefited from the supply boom.

The residential sector is composed of households that use natural gas primarily for heating and cooking. Our estimates imply that these households have substantially benefited from the price drop. Average residential natural gas bills have decreased by 19 billion dollars per year from 2007 to 2013; of this, we attribute 13 billion dollars per year to the supply boom (and the remaining portion to the impact of secular changes to overall demand). This bill change, however, does not represent the full benefit to consumers, who chose to consume more in response to the price fall. Overall, as indicated by table 2, the residential sector has benefited from the supply boom by $17 billion per year in increased consumer surplus

Table 4: Pass-Through of Henry Hub to Retail Natural Gas Prices

	Residential	Commercial	Industrial	Electric power
		Panel A: OLS		
Henry Hub price (long-run)	1.18	1.08	1.00	0.94
	(0.19)	(0.11)	(0.08)	(0.12)
		Panel B: 2SLS		
Henry Hub price (long-run)	0.99	1.03	0.99	1.02
	(0.14)	(0.07)	(0.08)	(0.06)

Note: This table reports results of the impact of Henry Hub prices (in levels) on retail prices (in levels) for each of the four retail sectors. As described in the text, the electric power price we use is the citygate price. Panel A reports OLS results of estimation of retail residential prices on lagged retail price, current Henry Hub price, and 1 throuh 11 lags of Henry Hub price. These regressions control for year effects and state by month effects. Standard errors are clustered by sample month. Panel B reports 2SLS results using only one lag of the Henry Hub price, instrumenting with lagged national weather. These regressions control for current and one-month lagged own-state weather, state by month effects, and a linear time trend. Standard errors are two-way clustered by sample month and state. Full results for both sets of regressions are shown in the appendix.

in 2013.

In the commercial sector, natural gas is again used primarily for heating. With one-to-one pass-through of wholesale to retail gas prices, consumer surplus will again not accrue to local gas providers. It is beyond the scope of this paper to divide the $111 billion increase in consumer surplus per year between employees, shareholders, and customers.

The fall in natural gas prices has transformed the electric power industry, as documented by a growing body of literature. Cullen and Mansur (2014), Holladay and LaRiviere (2014), Knittel, Metaxoglou and Trindade (2014), and Linn, Muehlenbachs and Wang (2014) document substantial coal-to-gas switching when natural gas prices fall, with implications for carbon emissions as well as local air pollutants such as SO_2, NO_x, particulate matter, and mercury. In analyzing the implications of low natural gas prices on fuel use in the electricity sector, much of the existing literature has focused on short-run impacts on the intensive margin, especially fuel use at existing plants. With respect to long-run effects, Brehm (2015) finds some evidence that natural gas power plant investment has been impacted, and Krupnick, Wang and Wang (2013) simulates changes in power plant capacity under various shale expansion scenarios. Davis and Hausman (2014) points to the effect of low natural gas prices on nuclear power plant financial viability; whether any plants will close because of fracking remains an open question.

In its analysis of the electricity sector, Linn, Muehlenbachs and Wang (2014) also examines the impact of shale gas on wholesale electricity prices. The fuel switching described above suggests that electric generators' natural gas demand is not constant elasticity as we have assumed, since the elasticity will be greatest over the gas price range in which coal-fired and gas-fired plants' marginal costs overlap. The impact of a fall in the price of natural gas on electricity prices depends on whether natural gas plans are on the margin, which in turn varies by hour, month, and region. In California, for instance, natural gas plants are on the margin in all hours, so wholesale electricity prices should be very sensitive to natural gas prices. In the Midwest, on the other hand, the very large capacity of coal-fired plants means that electricity prices are not always determined by natural gas prices. Generally, gas prices should have a larger impact in regions with lower coal-fired generation capacity; they should also have a larger impact at hours of day and times of year when demand is high enough for natural gas plants to be marginal. Matching this intuition, Linn, Muehlenbachs and Wang (2014) finds larger impacts for "on-peak" wholesale electricity prices; that is, prices at hours of day when demand is expected to be high.

The impact of lower wholesale electricity prices on end consumers of course depends on how retail electricity prices adjust. We expect one-to-one pass-through of wholesale electricity rates to retail rates in the long run, because of rate-of-return regulations. Overall, then, we should expect that lower electricity prices driven by the shale boom have benefited consumers, including both households and electricity-intensive industries. Infra-marginal power plants, such as those powered by coal or nuclear technologies, will have lost, and in the long-run, some of them may close.

In section 5, we consider the U.S. manufacturing sector in more detail. In particular, we show which industrial sectors have benefited the most from the decrease in the price of natural gas, and we discuss pass-through for a few important chemical products for which data are available.

3.3 Producers of Natural Gas

We now turn to estimating the change in producer surplus brought about by the shale boom. This exercise differs from that for consumer surplus in that we must consider not only the difference between counterfactual and equilibrium prices in 2013, but also the substantial shift in supply shown in figure 4. Thus, following figure 4, in order to calculate the change in producer surplus we must calculate the area bounded by the counterfactual pre-period price ($7.33 per mcf) and the 2007 supply curve (which we take to be the counterfactual 2013 supply curve), calculate the area bounded by the 2013 price ($3.88 per mcf) and the 2013 supply curve, and then take the difference.

One difficulty in performing this calculation arises from the fact that the shift in supply along the entire supply curve will affect the result. That is, we need to model the supply shift not just in the neighborhood of the 2007 and 2013 equilibrium quantities (i.e., the range of quantities shown in figure 4) but also all the way back to a quantity of zero. One potential approach to doing so would be to assume that the elasticity of supply is globally constant. This assumption is problematic, however, due to the large volume of inframarginal gas production that is being produced from wells drilled during or prior to 2007. For these wells, the marginal cost of production is essentially zero and is unaffected by the technological change that enabled the drilling, fracking, and production of shale gas resources.[23]

To calculate the quantity of 2013 production that comes from wells drilled prior to 2007 (inclusive), we follow Anderson, Kellogg and Salant (2014) by assuming that the 2007 production quantity would have declined exponentially had no new wells been drilled. We use a decline rate for conventional gas wells of 11.1% per year, obtained from Credit Suisse (2012). This value is similar to that estimated for Texas crude oil wells in Anderson, Kellogg and Salant (2014) (below, we examine the sensitivity of our results to this assumption). Given 2007 equilibrium natural gas production of 1,450 bcf/month, we therefore estimate that 717 bcf/month of 2013 natural gas production is inframarginal. Note that a small but non-trivial share of 2007 gas production was from shale reservoirs (8.1%).[24] Because shale gas wells are widely believed to experience steeper production declines than conventional wells, we are likely overestimating the volume of 2013 inframarginal production.

To extend the 2013 counterfactual and realized supply curves to a quantity of zero, we assume that marginal cost is zero for all quantities less than 717 bcf/month.[25] The resulting supply curves are presented along with 2013 demand in figure 5. In this figure, the supply curves to the right of 717 bcf/month are identical to those presented in figure 4 above. These portions of the supply curves represent gas production from new wells as a function of the natural gas price, per the elasticity estimated in section 1.2.[26]

Following figure 5, we now calculate producer surplus. In 2013, we estimate total producer surplus of $52 billion per year, of which $33 billion comes from inframarginal production and $19 billion comes from the elastic part of the supply curve. Inframarginal producer

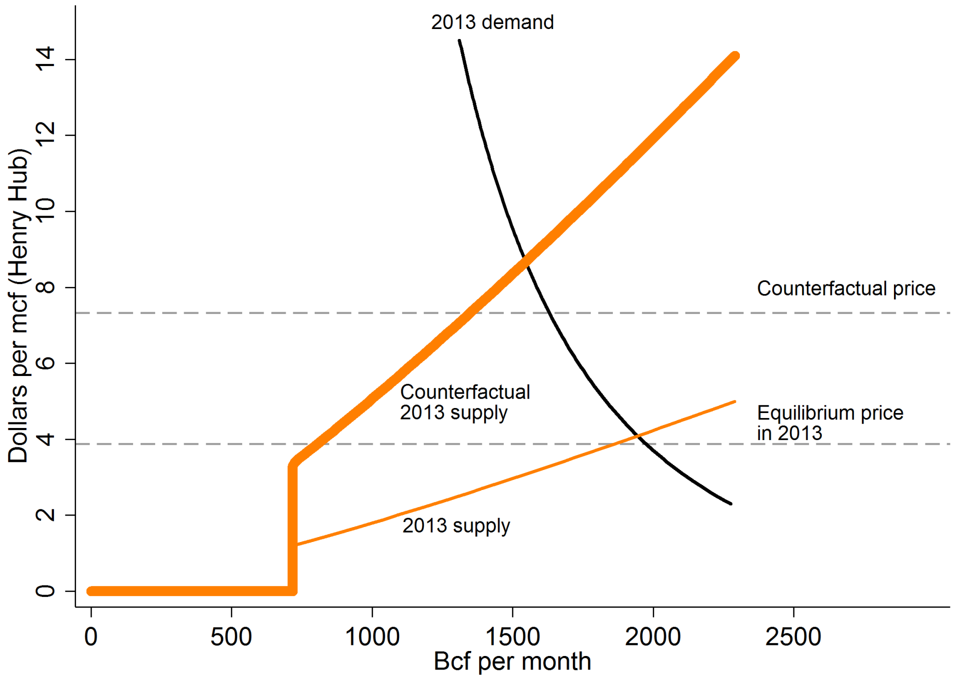
[23]See Anderson, Kellogg and Salant (2014) for a discussion of why the marginal cost of production from previously drilled wells is essentially zero, though that paper focuses on oil rather than gas wells.

[24]Per EIA gas withdrawal data, gross 2007 withdrawals were 24.66 tcf, and shale withdrawals were 1.99 tcf. The ratio is 8.1%.

[25]Our producer surplus change calculations would be unaffected by assuming a non-zero marginal cost, so long as this MC were smaller than the 2013 equilibrium price of ($3.88 per mcf). The key to the producer surplus change calculation is not the level of the MC, but rather the fact that the MC for production from previously drilled wells is not affected by shale gas drilling and fracking technology.

[26]This portion of the supply curves in figure 5 can be thought of as representing the amortized per mcf drilling cost for the marginal well at each production level.

Figure 5: Supply and Demand in the U.S. Natural Gas Market, Including Inframarginal Supply



Note: The vertical part of the supply curve denotes the quantity of 2013 natural gas production that we estimate to be coming from wells drilled during or prior to 2013. See text for details. As described in the text, the equilibrium prices are not at the intersection of domestic supply and demand, since they also account for imports and exports.

surplus under the counterfactual supply and gas price is much greater—$63 billion per year—owing to the substantially higher gas price in the counterfactual. However, surplus from the elastic portion of the supply curve is lower in the counterfactual—only $15 billion—since the equilibrium quantity produced is smaller. Overall, we find that 2013 producer surplus is *lower* than that of the counterfactual by $26 billion per year. This surplus reduction is driven entirely by losses to inframarginal producers that are adversely affected by the decrease in the natural gas price.[27]

Table 2 gives alternative estimates, using the alternative elasticity assumptions described earlier as well as alternative assumptions on the decline rate for existing wells. The change in producer surplus ranges from a drop of $8 billion per year to a drop of $40 billion.

The difference in the impact on inframarginal producers versus marginal producers drives substantial heterogeneity across gas producing states. In particular, states with large volumes

[27] If we had instead ignored the difference in marginal cost between marginal and inframarginal wells, the estimate for the change in producer surplus would have been -18 billion dollars per year. Our constant elasticity of supply would have implied that marginal cost shifted down everywhere along the supply curve, rather than just for new wells, and therefore producers would have lost less.

Table 5: State-level Impacts of Shale Gas on Producers

	2007 supply, bcf	2013 supply, bcf	Change in annual PS, billion $	Percent change in PS
Arkansas	232	980	1.1	104%
Colorado	1069	1380	-1.6	-32%
Louisiana	1174	2070	-0.6	-12%
New Mexico	1305	1028	-3	-52%
Oklahoma	1534	1844	-2.5	-36%
Pennsylvania	157	2803	5.4	758%
Texas	5266	6489	-8.3	-35%
Utah	324	405	-0.5	-34%
West Virginia	199	617	0.5	51%
Wyoming	1761	1598	-3.8	-48%

Note: In all states, the counterfactual price change is a fall of $3.45 per mcf, as described in the text. These ten states were the largest natural gas producing states over 2007 to 2013. Supply numbers are net of drilling and pipeline operations use and net of liquids extraction, as described in the text.

of conventional natural gas experienced decreases in producer surplus, while states with predominantly shale resources have seen increases. While we do not have comprehensive drilling data across states, we are able to observe production volumes for many individual states. Table 5 shows the change in producer surplus for the ten states with the greatest natural gas production over the period 2007 to 2013.[28] Arkansas, home to the Fayetteville play, and Pennsylvania, where the Marcellus Shale is located, both saw substantial increases in supply from 2007 to 2013. These supply increases were large enough to cause an increase in producer surplus. Pennsylvania in particular saw an increase in producer surplus of 5 billion dollars per year from 2007 to 2013. In contrast, most other states saw falls in producer surplus, as the increase from marginal producers was not large enough to offset the decrease in revenues from existing wells.

These surplus calculations are simplified as they are derived from a static framework. For instance, losses to inframarginal producers will extend forward into time because shale gas will continue to depress the natural gas price, though the losses will diminish over time as the inframarginal production rate decays (conversely, monthly inframarginal losses were higher in years before 2013 when inframarginal production was greater). Gains to owners of newly-drilled wells will be spread over the lifetimes of these wells. The estimated producer

[28]Disaggregation across states introduces some error into the producer surplus estimates. In particular, the 2013 supply curve for the United States as a whole is not a linear sum of the state-level curves, because of the kink. The national estimate probably more closely reflects the true marginal cost curve: the constant elasticity assumption at the state level leads to underestimates of marginal cost for some new wells in states like Pennsylvania.

surplus changes are therefore best interpreted as estimates of surplus flows for 2013 that will evolve over the years to come.

Producer surplus likely accrues to several types of economic agents. For production from legacy wells, surplus is split between mineral rights owners and leaseholders (oil and gas production companies) per production royalties. Mineral rights owners' royalty shares are usually between 10% and 25% of revenue. State governments may also be affected through severance taxation (see Raimi and Newell (2014) for a summary). For new wells, surplus will also accrue to owners of scarce capital—in particular, owners of drilling rigs and fracking equipment. Skilled labor shortages may also cause rents to accrue to workers. Indeed, it is this capital and labor scarcity that gives rise to the upward slope in the supply curves in figures 4 and 5 (see Anderson, Kellogg and Salant (2014) for a discussion).

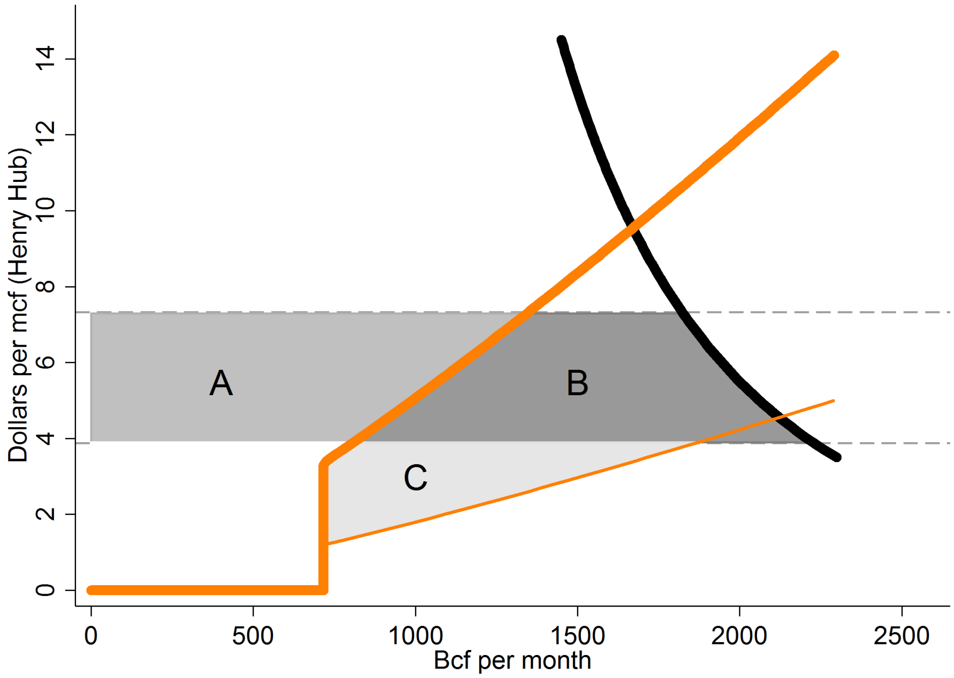
The overall welfare change from shale gas accruing to consumers and producers is shown in figure 6. Area A is the transfer from producers to consumers; area B is new consumer surplus, and area C is new producer surplus. Thus the change in total surplus is the combination of B and C, equal to \$48 billion per year. That is, the welfare gains accruing to natural gas consumers more than offset the losses accruing to natural gas producers. Table 2 gives alternative estimates for the total change in surplus, ranging from a low of \$37 billion per year to a high of \$56 billion; the alternative assumptions on elasticities or decline rates impact the estimated transfer from producers to consumers more than they impact the total change in surplus.

4 Impacts From LNG Exports

Beyond shedding light on the impacts of the shale gas revolution to date, our framework is also useful for assessing the potential impacts of policies that will affect the U.S. natural gas market. In particular, a debate has emerged regarding whether to permit large-scale overseas export of liquified natural gas (LNG). Exporting LNG is expensive; however, the large differential between the U.S. gas price and prices in Europe and Asia (figure 2) has spurred strong interest in construction of LNG export terminals. As of February 5, 2015, the Federal Energy Regulatory Commission (FERC) has approved construction of five export terminals with a total planned capacity of 9.2 bcf per day (FERC 2015a), and 14 additional terminals have been proposed, having a total planned capacity of 15.4 bcf per day (FERC 2015b). All of the approved projects are currently under construction.

Our natural gas demand and supply model illustrated in figure 4 provides guidance on how expanding natural gas exports will impact consumer and producer welfare. Holding domestic demand and supply fixed at 2013 levels, LNG exports will drive up the U.S. equilibrium

Figure 6: Change in Surplus



Note: The thick lines show 2007, and thin lines 2013. As described in the text, the equilibrium prices are not at the intersection of domestic supply and demand, since they also account for imports and exports.

natural gas price, reducing consumer surplus but increasing producer surplus. In this section, we use our model to quantify these effects for two scenarios: (1) LNG exports equal to the capacity of all approved LNG projects, and (2) LNG exports equal to the capacity of all approved and proposed LNG projects. These calculations complement EIA (2014), which simulates U.S. natural gas price, production, and consumption impacts from LNG exports using a variety of modeling scenarios from the 2014 EIA Annual Energy Outlook. Another related paper is Arora and Cai (2014), which studies potential global impacts from LNG exports.

Our analysis holds the U.S. domestic supply and demand curves for natural gas constant at their 2013 locations, as estimated in section 2. We also assume, as in section 2, that the function for non-LNG net imports from Canada and Mexico is constant. Thus, when we simulate LNG exports, the resulting gas price increase will cause a decrease in U.S. consumption, an increase in U.S. production, and an increase in non-LNG net imports.

Under the LNG export scenarios, we calculate the equilibrium U.S. natural gas price by finding the price at which the U.S. quantity produced minus the U.S. quantity consumed, plus non-LNG net imports, equals LNG exports. The resulting price in the "approved LNG" scenario is \$4.37 per mcf (relative to the 2013 equilibrium price of \$3.88 per mcf), and the price in the "approved plus proposed LNG" scenario is $5.24 per mcf. These equlibrium prices under LNG export are shown in figure 7.

We also calculate the changes in consumer and producer surplus, relative to the 2013 equilibrium, for both LNG scenarios. Under approved LNG exports, U.S. consumer surplus contracts by $11.5 billion per year, and this effect is almost exactly offset by an expansion of U.S. producer surplus by $11.6 billion per year (the net effect is an increase in surplus of $0.1 billion per year). This near-perfect offset seems at first surprising, as an expansion of export capacity is typically thought to increase producer surplus by more than it decreases consumer surplus. In this case, however, net imports from Canada and Mexico also play an important role. Because the U.S. is still a net importer of gas in 2013 (with the imports coming from Canada), the increase in producer surplus brought about by LNG exports is shared between U.S. and Canadian producers. Thus, while LNG exports must increase the sum of consumer and producer surplus for all of North America, this sum need not increase for the U.S. alone. In fact, for sufficiently small LNG exports, the sum of U.S. consumer and producer surplus will decrease. The intuition for this effect can be seen in figure 7: starting from the 2013 equilibrium, a small increase in the U.S. gas price reduces U.S. consumer surplus more than it increases U.S. producer surplus.

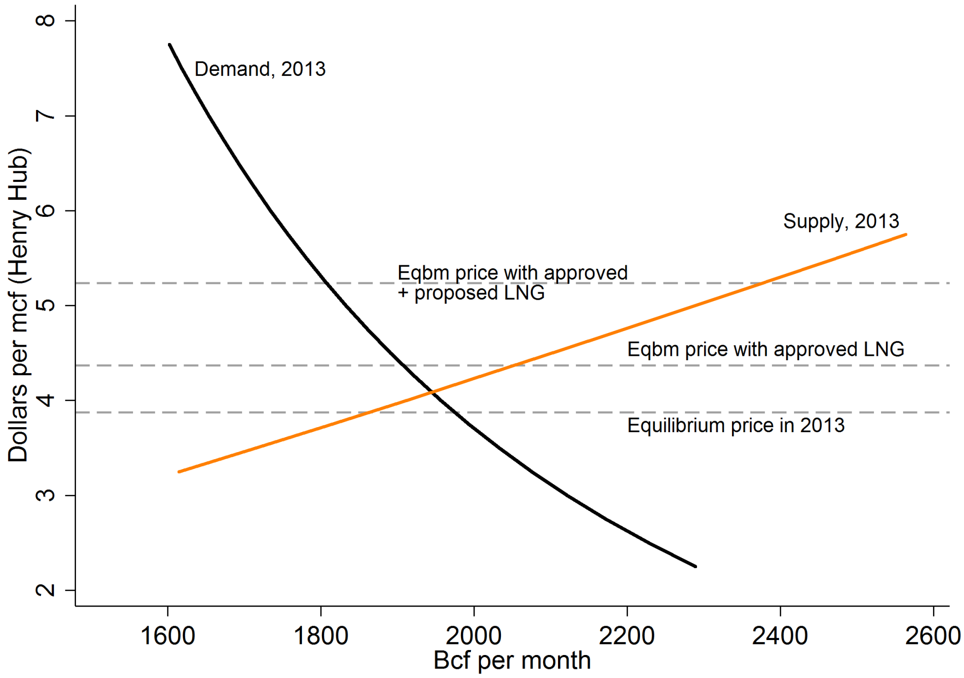
For the "approved plus proposed LNG" scenario, the decrease in U.S. consumer surplus of $31 billion per year is more than offset by an increase in U.S. producer surplus of $35 billion per year. For this large expansion of LNG, the substantial increase in U.S. gas production generates gains to producers that outweigh the losses to consumers.

Finally, it is important to note that these welfare calculations do not include any rents accruing to the firms that invest in and operate the LNG export facilities. These rents will be generated if the exported quantity is insufficient to bring the price difference between international and U.S. natural gas down to the level of the long-run LNG transportation cost (including liquifaction and re-gasification). Thus, it may be that for a small quantity of LNG exports, the sum of the change in U.S. consumer, producer, and exporter surplus will be positive. Addressing this issue quantitatively is beyond the scope of this paper.

5 A Manufacturing Renaissance?

Considerable interest has been directed toward the question of whether the shale gas revolution will result in a "renaissance" in U.S. manufacturing. Natural gas is an important direct input to industries such as chemical, plastics, and cement manufacturing, and through its use in electricity generation it is an indirect input to essentially all manufacturing. Analysts have forecasted large employment gains in manufacturing because of low natural gas prices

Figure 7: Impacts from LNG Exports



Note: FERC-approved LNG exports are 9.2 bcf/d (280 bcf/month), and FERC-approved plus proposed LNG exports are 24.6 bcf/d (748 bcf/month). The 2013 equilibrium price is not at the intersection of domestic supply and demand because net imports (from Canada and Mexico) are positive. For the LNG scenarios, we assume a linear function for non-LNG net imports, as described in the text.

(PWC, 2011, 2014). In this section, we explore the extent to which the new availability of low-cost natural gas has spurred the expansion of U.S. industries with gas-intensive production processes. Note that our analysis in this section does not consider how the shale revolution may have caused some sectors (such as steel pipe manufacturing) to expand employment and output through their production of inputs to the oil and gas industry. Changes in surplus earned via the manufacturing of such products are in principle included in our producer surplus calculations.

Our investigation complements a recent empirical working paper, Melick (2014), which finds, using energy intensity and business activity data aggregated to 80 sectors, that gas-intensive manufacturing sectors respond more strongly to natural gas price shocks than other manufacturing sectors. The paper's regression results imply that the most energy-intensive sectors have expanded by 30% in response to the change in natural gas prices from 2006–2013. Our approach differs in that we study highly disaggregated U.S. Economic Census data, ultimately broken out into 230 manufacturing sectors, which allows for greater focus on particularly gas-intensive industries.

We obtain data on sector-level manufacturing activity from the 2002, 2007, and 2012

Economic Censuses (ECs). An advantage of these data is their level of disaggregation: there are 473 manufacturing sectors in 2002, 471 in 2007, and 364 in 2012. For each EC year, we gather for each industry the number of establishments, total employment, total compensation, and total capital expenditure.[29]

We obtain measures of sector-level natural gas intensity from the Bureau of Economic Analysis (BEA) 2007 input-output (IO) tables.[30] These tables provide industry input requirements and product outputs for 389 sectors, of which 238 are in manufacturing (North American Industry Classification System (NAICS) codes beginning with 3). In the BEA system, direct natural gas inputs into manufacturing flow almost entirely through sector 221200, natural gas distribution.[31] In addition, all sectors consume natural gas indirectly, especially through their use of electricity. Our natural gas intensity measure for each manufacturing sector is therefore its total (direct + indirect) input requirement from sector 221200,[32] which can be calculated directly from the IO tables.[33] These industry requirements are measured in dollars of natural gas input per dollar of industry output, all at 2007 prices. Finally, we merge our BEA gas intensity data with the EC data by NAICS code. This merge requires aggregation of the EC sectors to match the smaller number of BEA sectors, though there are a small number of BEA sectors that also require aggregation to match the 2012 EC.[34] Our final matched dataset has 230 manufacturing sectors.

[29] The ECs also provide information on the dollar value of each sector's output and its value added. We do not use this information because it introduces considerable noise from fluctuations in industrial commodity prices.

[30] An alternative data source would be the EIA's 2010 Manufacturing Energy Consumption Survey (MECS); however, the MECS data are much more aggregated, with many sectors reported at the 3-digit NAICS level.

[31] Manufacturing sectors also receive small input flows from sector 211000, oil and gas extraction. It is not clear whether these flows reflect natural gas input (which we would like to capture in our intensity measures) or oil / petroleum input (which we do not want to capture). To be conservative, we do not reclassify these small flows into NAICS 221200.

[32] The results of our analysis are qualitatively unchanged if we instead only use direct natural gas requirements.

[33] The total requirements table is calculated as $(I - MD)^{-1}$, where M is the Make table (production by each row industry of each column commodity), D is the direct requirements table (dollars of each commodity row input per dollar of column industry output), and I is the identity matrix. The manufacturing sector natural gas requirements come from the row of the total requirements table corresponding to NAICS 221200. The raw D matrix from the BEA has electricity generation obtaining its gas requirement almost entirely from NAICS 211000 (oil and gas extraction) rather than NAICS 221200. We therefore transfer this requirement to NAICS 221200 before calculating the total requirements table (this transfer is valid because only a trivial fraction of electricity generation uses petroleum products as fuel).

[34] The only sector that does not cleanly merge across the EC and BEA data is NAICS 339100 (medical equipment). Subsector 339111 appears in the 2002 EC but not in the other datasets, and the other datasets also lack an "other medical equipment" category in which 339111 might be included. We therefore drop NAICS 339100 from our analysis. We also drop sectors 316000 (leather and allied products), 331410 (smelting of non-ferrous and non-aluminum metals), and 335224 (household laundry equipment manufacturing) because their data were omitted from some EC years due to confidentiality issues.

Table 6: Natural Gas Intensity for Manufacturing Sectors at or above the 90th Percentile

NAICS Code	Sector	Gas intensity (dollars of gas per dollar of output)	Weighted intensity percentile	2007 Industry output ($million)
33131B	Aluminum product manufacturing from purchased aluminum	0.034	90	25770
313300	Textile and fabric finishing and fabric coating mills	0.034	91	8995
311210	Flour milling and malt manufacturing	0.034	91	13264
331314	Secondary smelting and alloying of aluminum	0.036	91	7698
325180	Other basic inorganic chemical manufacturing	0.038	91	29165
3252A0	Synthetic rubber and artificial and synthetic fibers and filaments manufacturing	0.040	92	15498
325211	Plastics material and resin manufacturing	0.041	92	83876
327992	Ground or treated mineral and earth manufacturing	0.042	94	3102
33131A	Alumina refining and primary aluminum production	0.043	94	7798
327993	Mineral wool manufacturing	0.044	94	5836
327100	Clay product and refractory manufacturing	0.046	94	8373
327200	Glass and glass product manufacturing	0.051	94	22955
325190	Other basic organic chemical manufacturing	0.052	95	97786
322120	Paper mills	0.054	97	49742
322110	Pulp mills	0.060	98	5049
322130	Paperboard mills	0.067	98	25216
327310	Cement manufacturing	0.069	98	10182
325110	Petrochemical manufacturing	0.073	98	75752
311221	Wet corn milling	0.082	100	11728
327400	Lime and gypsum product manufacturing	0.094	100	7392
325310	Fertilizer manufacturing	0.143	100	17348

Note: Natural gas intensity is the total (direct + indirect) gas requirement for each sector divided by the sector's output. These values are derived from the 2007 BEA IO tables as described in the text. 2007 industry output is from the 2007 BEA Make table. Intensity percentiles are weighted by 2007 BEA industry output.

Across all sectors, the weighted average natural gas intensity is $0.018 of gas input per dollar of output (weighting is by 2007 BEA industry output). However, there is considerable variation and right-skewness in the intensity data. Table 6 presents the natural gas intensity for each sector at or above the 90th intensity percentile. The 90th percentile sector, "aluminum product manufacturing from purchased aluminum," has a gas intensity of 0.034, 84% greater than the average. The most gas-intensive manufacturing sector in the economy, fertilizer manufacturing, has a gas intensity of 0.143 (680% greater than the average). The gas intensity of the fertilizer industry is actually 53% greater than that of the second-most gas intense industry, lime and gypsum product manufacturing. This particularly high natural gas intensity derives from the fact that natural gas is the chemical feedstock for virtually all nitrogen-based fertilizer production (i.e., gas is not used merely for process heat).[35]

Our first analysis of manufacturing sector growth is presented in table 7. This table shows changes in manufacturing establishment counts, employment, employee compensation, and

[35] Nitrogen-based fertilizers are derived from ammonia (NH_3), which is made by combining atmospheric nitrogen with hydrogen via the Haber process. Hydrogen is in turn produced via steam reforming of natural gas: reacting natural gas (CH_4) with water (H_2O) to produce hydrogen (H_2) and carbon dioxide (CO_2).

Table 7: Changes in Manufacturing Sector Activity: 2002–2007 and 2007–2012

Years	Number of establishments	Employment	Employee compensation	Capital expenditure
Sectors with natural gas intensity < 90th percentile				
2002 to 2007	-5.8%	-9.0%	9.9%	21.3%
2007 to 2012	-10.6%	-16.5%	-3.7%	4.9%
Sectors with natural gas intensity ≥ 90th percentile				
2002 to 2007	-3.5%	-14.7%	-1.9%	36.8%
2007 to 2012	-6.2%	-13.1%	4.3%	8.5%
Sectors with natural gas intensity ≥ 95th percentile				
2002 to 2007	-0.6%	-14.3%	-1.0%	46.5%
2007 to 2012	1.7%	-8.6%	9.1%	2.5%
Fertilizer manufacturing (NAICS 325310)				
2002 to 2007	-9.5%	-15.8%	8.5%	20.4%
2007 to 2012	8.3%	8.6%	24.8%	232.7%

Note: Manufacturing sector activity data come from the 2002, 2007, and 2012 economic censuses (ECs) and are merged with sector-level natural gas intensity data per the discussion in the text. Values shown are percent changes in activity from the 2002 to 2007 EC and from the 2007 to 2012 EC. Percentile classifications of sectors are weighted on 2007 sector output from the BEA. Sector-level percentiles for sectors above the 90th percentile are shown in table 6.

capital expenditure between the 2002 and 2007 ECs, and between the 2007 and 2012 ECs. We focus our attention on changes from 2007 to 2012, as this was the period during which the shale boom substantially decreased the U.S. natural gas price. Table 7 groups sectors by their manufacturing intensity, separately presenting activity changes for sectors below the 90th intensity percentile, for sectors above the 90th percentile, for sectors above the 95th percentile, and for fertilizer manufacturing.

The first set of rows in table 7 shows that sectors outside the 90th intensity percentile have experienced declining establishment counts, employment, and employee compensation, especially over the 2007–2012 period that includes the Great Recession. The remaining rows show that these declines were not as steep for sectors above the 90th and 95th intensity percentiles, and that employee compensation actually increased for these sectors. For fertilizer manufacturing, by far the most gas-intensive manufacturing sector, the establishment count, employment, and compensation all increased considerably between 2007 and 2012. The change in capital expenditure from 2007 to 2012, while positive for non-gas-intensive sectors, is larger for sectors above the 90th percentile, and was a massive 233% for fertilizer manufacturing. It is therefore clear that manufacturing sectors that are particularly gas intensive have expanded relative to other manufacturing sectors since the onset of the shale gas boom.[36]

Interpretation of the changes in gas-intensive manufacturing activity as being caused by the shale boom requires a counterfactual for what would have happened during 2007–2012 absent shale gas. One possible counterfactual is that gas-intensive sectors would have experienced the same contraction as did non-gas-intensive sectors. In this case, the effect of shale gas on gas-intensive manufacturing is given by the difference between 2007 to 2012 activity changes for intense versus non-intense sectors. Specifically, under this counterfactual shale gas caused sectors above the 90th intensity percentile to experience increases in establishments, employment, compensation, and capital expenditure of 4.4%, 3.4%, 8.0%, and 3.6%, respectively. An alternative counterfactual is that gas-intensive sectors' activity changes from 2007–2012 would differ from changes in non-gas-intensive sectors according to the 2002–2007 pre-trends. For instance, employment in sectors above the 90th percentile decreased by 5.7 percentage points more than employment in non-gas-intensive sectors between 2002 and 2007, and we might have expected this difference to persist over 2007–2012 absent shale gas. Under this counterfactual, the shale boom caused sectors above the 90th intensity percentile to experience increases in establishments, employment, compensation of 2.2%, 9.1%, and 19.8%, respectively, and a decrease in capital expenditure of 11.9% (the "triple differenced" capital expenditure effect is positive, however, for fertilizer manufacturing).

Overall, this analysis suggests that employment in gas-intensive industries was 3.4% to 9.1% higher in 2002 because of low natural gas prices, a noticeable impact. However, total employment for the industries at or above the 90th percentile of natural gas intensity was only 710,000 in 2013, implying that the number of additional jobs from fracking in those industries was in the range of 24,000 to 65,000.

What about employment impacts for manufacturing sectors outside the 90th percentile? Given that average gas intensity in manufacturing is only 2%, we do not expect large percentage changes in employment from the gas price change. It is plausible, however, that even a small percentage change could imply many additional jobs, when aggregated across all of manufacturing. To analyze this possibility, we estimate the correlation between gas intensity and changes in manufacturing employment from 2007 to 2012. Specifically, we regress log employment by industry in 2012 on gas intensity, controlling for log employment in both 2002 and 2007 and weighting by industry output.[37] Conceptually, this regression is similar

[36]The establishment count, employment, and compensation changes for 2007–2012 for sectors above the 90th percentile are greater than those for sectors below the 90th percentile even if fertilizer manufacturing is excluded. Establishments, employment, and compensation change by -7.1%, -13.7%, and 3.8%, respectively. Changes relative to the 2002–2007 pre-trend are still substantially larger than for non-intense sectors. The change in capital expenditure, however, is relatively small: 2.7%.

[37]This regression relies on the employment elasticity with respect to gas prices being proportional to gas share. This proportionality is true for a CES production function and constant elasticity demand.

to the "triple differenced" numbers we report above, but it allows us to study changes within the non-gas-intensive sectors. Including log employment in 2002 and 2007 as explanatory variables is important, since pre-existing secular trends in manufacturing activity may be correlated with gas intensity. Additionally, we control for 3-digit NAICS codes to isolate the variation within broad categories of manufacturing.

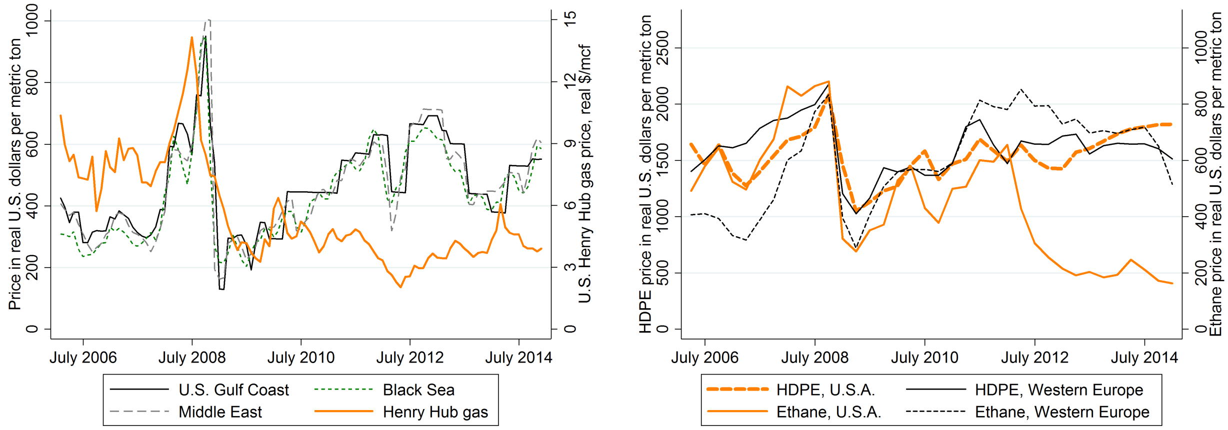
We estimate a coefficient on gas intensity of 1.3 (with a standard error 0.8; full regression results in the appendix), suggesting that for every additional percentage point of gas intensity, employment in 2012 was 1.3% higher. Assuming that a zero-gas-intensity sector would experience no change in employment from the natural gas price fall, we can calculate total employment impacts as follows. First, we multiply, for each sector, the coefficient on gas intensity by the sector's gas intensity level and by its employment in 2007, yielding the change in the number of jobs in that sector associated with the change in the sector's natural gas input cost. Summing across sectors, we find an increase in manufacturing employment of around 280,000 in 2012; the 95% confidence interval is -60,000 to 610,000. For comparison, total manufacturing employment in 2012 was around 11 million. Overall, while it is difficult to pinpoint a precise causal effect, the balance of the evidence suggests that manufacturing has experienced an expansion of activity as a result of the shale boom. The total employment effect would, of course, depend on whether new jobs in manufacturing were moved from other sectors (a multiplier less than one) or whether this growth contributed to employment in other sectors (a multiplier greater than one).

We conclude this section by studying prices for two gas-intensive chemical products for which data are readily available: ammonia, a major fertilizer and the precursor to nearly all other nitrogen-based fertilizers, and high density polyethylene (HDPE), a common type of plastic. Ammonia is manufactured using methane, the primary chemical component of natural gas, as a direct input. HDPE can be produced using ethane as a feedstock (with ethylene as a crucial intermediate product), and ethane is the second most common component of natural gas.[38] These two products are interesting because, relative to their natural gas inputs, their international transportation costs are low. Whereas methane has a boiling point of $-161\,^{\circ}$C, and ethane has a boiling point of $-89\,^{\circ}$C, ammonia boils at $-33\,^{\circ}$C, and HDPE is a solid at room temperature, facilitating their shipment.

The ease of trade for ammonia and HDPE leads to international parity in their prices. The left panel of figure 8 presents time series of ammonia prices for the U.S. Gulf Coast, the Black Sea, and the Middle East. The figure makes clear that ammonia prices in these three regions are tightly linked despite large overall price fluctuations. In particular, the

[38]HDPE can also be produced through the processing of crude oil, where the long-chain hydrocarbons in crude can be "cracked" to produce ethylene.

Figure 8: U.S. and International Ammonia, Ethane, and HDPE Prices



Source: Bloomberg.

U.S. ammonia price does not substantially diverge from Black Sea and Middle East prices after 2007, despite the large decrease in the U.S. natural gas price. The right panel of figure 8 shows a similar result for HDPE and its input, ethane.[39] The U.S. and Western European HDPE prices follow each other closely, even though the U.S. ethane price has fallen far below ethane prices in Western Europe. The lack of pass-through of U.S. natural gas prices to ammonia and HDPE prices implies that the welfare gains for these sectors caused by cheap natural gas are accruing almost entirely to manufacturers rather than consumers.

The divergence between U.S. ammonia and natural gas prices also helps to explain the tremendous expansion of U.S. fertilizer manufacturing shown in table 7 above. Because ammonia prices are set on a large global market, U.S. fertilizer manufacturers are able to expand their production without substantially affecting their output price. While we lack sector-specific employment and production data for HDPE, the EIA reports that several firms have now planned substantial investments in chemical plants that will use ethane to produce ethylene, a key ingredient for HDPE and other plastics (EIA, 2015). This new capacity—driven by low U.S. feedstock prices relative to prices elsewhere—is expected to increase ethylene production by 40% once it comes online in 2017 or 2018 (EIA, 2015).

6 Environmental Externalities and Regulation

Scientists have identified a number of potential environmental impacts from fracking, although much research is still needed. Below we briefly summarize the concerns brought

[39]The U.S. ethane prices are FOB contract prices, and the Western Europe ethane prices are derived by Nexant. We obtain both series from Bloomberg.

forward to date. We then discuss how the existing environmental economics literature might shed light on the options available to regulators.

6.1 Global Environmental Impacts

Unconventional natural gas extraction could impact climate change via several mechanisms, and overall the impact could be to either decrease or increase total greenhouse gas emissions (McJeon et al., 2014; Newell and Raimi, 2014). First, methane leaks can occur throughout the natural gas production chain, and methane is a powerful greenhouse gas. The rate at which methane is leaking from the supply chain is much debated (Moore et al., 2014); this is in part because it is very heterogeneous across producers and sites (Brandt et al., 2014). Below we discuss how this uncertainty impacts the optimal regulatory approach.

The second way fracking could impact climate change is through its combustion as fuel. Two effects operate here: the lower price of natural gas encourages total energy use to rise (a scale effect) and also encourages substitution away from other fuels, both less carbon-intensive (renewables and nuclear) and more carbon-intensive (coal and oil). According to simulations by Newell and Raimi (2014), the coal displacement effect has dominated both the scale effect and the effect on renewables and nuclear use, so that domestic emissions from combustion have decreased. After incorporating the effect of methane leaks, however, their results for overall domestic greenhouse gas emissions are inconclusive. Moreover, the total global impact depends on how much coal exports have increased. Newell and Raimi (2014) suggest the coal export effect is small, but more research on the global coal market is needed to definitively answer this question.

To illustrate the wide variation in potential climate impacts, consider two bounding scenarios.[40] First, suppose that all displaced coal is exported, and international coal production is not reduced at all (this is an extreme bound, both because some displaced coal is likely not extracted, and some international coal production is reduced). In this case, there are no substitution benefits, and CO_2 emissions increase from the scale effect. In this case, CO_2 emissions would have increased by 340 million tons in 2013 because of fracking; at the IWG's[41] social cost of carbon (SCC) of \$40/ton, this would be worth 13 billion dollars per year. Additionally, taking the highest methane leak rate number in the recent literature (7.9%), methane emissions would have increased from 2007 to 2013 by 11 million tons; with a global warming potential of 34, this would be worth an additional 15 billion dollars per year.

[40] Parameter assumptions and calculations are given in the appendix.

[41] IWG: Interagency Working Group on the Social Cost of Carbon, United States Government. See the appendix for details.

At the other extreme, consider the case where the increase in gas-fired electricity generation displaced coal with no offsetting increase in exports (or equivalently, assume any increase in coal exports was completely offset by reductions in coal production abroad). In this lower bound case, CO_2 emissions from electricity production would have decreased by 160 million tons in 2013 because of fracking, implying a savings of 6.5 billion dollars per year. Residential, commercial, and industrial sector emissions, however, still would have increased by almost 130 million tons, for a cost of 5.3 billion dollars per year. Overall, in this lower bound case, fracking would have led to a savings of 1.2 billion dollars per year from reduced CO_2 emissions. For a lower bounding case for methane leaks, a leak rate of 0.42% would imply an increase in methane emissions of 0.5 million tons, worth 0.5 billion dollars per year.

Overall, then, this bounding exercise suggests that the climate change impacts of fracking in 2013 could have been anywhere from an increase in environmental costs of 28 billion dollars per year to a decrease in costs of 0.7 billion dollars per year, at a social cost of carbon of $40/ton. Some of this range is from uncertainty regarding coal displacement, and some is from uncertainty over methane leaks. An additional caveat is important and points to the need for additional research. The long-run impact of low natural gas prices on the transition to a less carbon intensive energy sector depends crucially on how the prices affect investment decisions (for new power plants, the vehicle fleet, etc.) as well as future expenditures on research and development (R&D). Existing models, such as the EPA's NEMS model, incorporate investment decisions, but impacts on R&D are largely unknown. It is worth highlighting that, while technology has advanced for renewable energy sources such as solar and wind, the pace of technological advances for oil and gas extraction in recent years has been astounding. In the absence of climate policy, renewables must advance technologically faster than fossil fuels in order to displace them.

6.2 Local Environmental Impacts

The environmental impact that has perhaps attracted the most attention to date is the potential for water contamination. Contamination can occur at several stages of the extraction process, impacting either surface or groundwater. Damages can result from the natural gas itself, the toxic fluids used in the fracking process, or other naturally occurring chemicals released by the fracking process (Burton, Nadelhoffer and Presley, 2013). Concern has also been raised about the volume of water used for fracking, and the potential for surface or groundwater depletion. For a review of studies analyzing the risks to water, see Jackson et al. (2014), Mason, Muehlenbachs and Olmstead (2014) and Small et al. (2014); the EPA is also currently undertaking a large-scale review of water impacts (EPA, 2011).

A second area of concern relates to local air quality. Emissions of criteria and toxic pollutants could again result from several components of the extraction process, including the well itself, compressor stations, or transport equipment (Mason, Muehlenbachs and Olmstead, 2014; Moore et al., 2014).[42] Unconventional gas extraction also involves a great deal of transport equipment. In addition to creating road dust, the increased trucking can lead to increased traffic accidents and fatalities (Graham et al., 2015).

Additionally, scientists have pointed to earthquakes associated with the injection of wastewater in fracking operations (EPA, 2014; Small et al., 2014). Comprehensive analysis of this seismic activity is still lacking. As with conventional oil and gas extraction activity, habitat fragmentation can also occur, and studies specific to the areas being newly developed for unconventional gas are still limited (Small et al., 2014; Mason, Muehlenbachs and Olmstead, 2014). The final local externality that has raised concern is the suite of disamenities associated with a rapidly growing "boomtown," including noise and crime. Overall, the empirical evidence on these disamenities is mixed (Jacquet, 2014; Mason, Muehlenbachs and Olmstead, 2014; Raimi and Newell, 2014), but they may well be large in some regions.

Overall, a number of local environmental impacts have been identified, and site-specific studies are accumulating. One recent study has found an impact of drilling on infant health in Pennsylvania, but the precise mechanism is unknown (Hill, 2013). For all of the impacts, more analysis is still needed on the magnitude, the geographic scope, and economic valuation of the damages (Mason, Muehlenbachs and Olmstead, 2014; Small et al., 2014).

6.3 Valuation of Local Damages

A valuable complement to our consumer and producer surplus calculations would be a full monetization of environmental damages. Unfortunately, that is not possible given the state of the data on water and air quality. Mason, Muehlenbachs and Olmstead (2014) summarizes the limited damages estimated in the literature to date. One strand of the environmental economics literature on this issue has focused on housing prices (Muehlenbachs, Spiller and Timmins, 2012, 2014). In theory, home values can fully capitalize the value of all local environmental disamenities to the marginal resident. However, interpretation of results on housing prices is difficult for several reasons. First, the change in housing prices reflects not only environmental disamenities but also the local boom in economic activity and resource rents associated with extraction. Second, responses of housing prices to changes in disamenities do not in general reveal marginal valuations or welfare changes when households have

[42] There are some local air quality benefits associated with increased natural gas production: it leads to displacement of coal in electric power generation, and therefore reductions in pollutants such SO_2, NO_x, particulate matter, and mercury.

heterogeneous preferences (Kuminoff and Pope, forthcoming; Haninger, Ma and Timmins, 2014). Finally, if information on environmental impacts is incomplete, the values of the homes reflect only the *perceived* level of environmental disamenities. This last issue is particularly important in the context of fracking, where the extent of and spatial heterogeneity in damages remains unknown.

6.4 Regulatory Approaches

Environmental regulation for fracking varies considerably across locations (Richardson et al., 2013), but in general, comprehensive and cost-effective environmental regulation has lagged behind the rapid rise of unconventional natural gas. While some states and localities have outright banned fracking, other areas have allowed the industry to rapidly move forward. From an efficiency perspective, this variation in policy approaches is unlikely to be optimal. Several factors have impeded the development of unified and cost-effective regulation. As the previous discussion made clear, a great deal of uncertainty still surrounds the location and extent of the damages outlined. The damages are likely to be heterogeneous across space; groundwater contamination and methane leaks, for instance, both depend on the integrity of equipment (Allen et al., 2013; Ingraffea et al., 2014), and will thus vary across producers and sites. This heterogeneity affects the ability of the scientific community to estimate the magnitude of the overall problem; it also limits the ability of policy-makers to rapidly target the environmental impacts of greatest concern.

It is worth considering fracking in the light of other environmental problems where uncertainty and lack of data are present. In particular, we highlight both poor monitoring and difficult attribution of liability. We begin by discussing examples of uncertainty around environmental damages from fracking; then we discuss implications for regulators.

To hold individual producers accountable for the damages they cause, regulators must (1) observe a baseline level of environmental quality; (2) document a change in environmental quality from fracking; and (3) attribute the change directly to an individual producer. The first problem to date, then, has been lack of complete data on baseline environmental quality levels for surface water, groundwater, and air quality (Adgate, Goldstein and McKenzie, 2014; Burton, Nadelhoffer and Presley, 2013; Moore et al., 2014; Small et al., 2014). Even in locations where baseline and post-fracking water quality have been measured, it remains difficult to hold individual producers liable (Davis, 2015). As Fitzgerald (2013) points out, "fracking occurs far underground, where verification is costly if not impossible" (p 1356). Contamination occurs if wells are poorly encased (Darrah et al., 2014; Fitzgerald, 2013; Ingraffea et al., 2014; Vidic et al., 2013), but monitoring every individual well is costly

(Davis, 2015). Researchers have found that incomplete data on well casing integrity poses a real challenge (Jackson et al., 2014).

Comprehensive monitoring and attribution of methane emissions is also difficult. Methane can be emitted from a number of sources throughout the extraction process; for a description, see Allen et al. (2013) and Moore et al. (2014). Direct measurement of most of the individual sources is possible, but such measurements to date have been limited to snapshots taken at a small sample of sites (Allen et al., 2013; Brandt et al., 2014). An alternative is to measure the entire plume at a downwind location, so that only one measurement is needed. However, a suitable downwind location is not available at all sites (Allen et al., 2013); moreover, a regulator must then prove that all of the observed emissions are from a given producer, rather than other nearby sources. The EPA has struggled with similar difficulties in other industries, such as refining.[43]

Cost-effective regulation is extremely challenging in settings with incomplete data and imperfect attribution. The standard market-based incentives that economists prefer, such as emissions taxes or cap-and-trade programs, can only be used with high quality monitoring. The efficiency of these incentives is predicated on rewarding the firms that engage in clean production while punishing firms that emit—clearly this requires attribution to individual firms.

In the absence of market-based incentives, two broad types of regulatory approaches are currently in place (in addition to outright bans and moratoria). The first is holding producers liable for accidents ex-post through the judicial system. This again requires proof of damages, so the data quality and attribution issues discussed above still apply. Moreover, incentives for emissions abatement can be greatly distorted when penalties are applied through the tort system (Davis, 2015). As an example, bankruptcy protection will exempt very small firms from ex-post liability of large accidents (Boomhower, 2014).

The second regulatory approach currently in place is command-and-control regulation, mainly technology standards. For instance, individual state environmental agencies have imposed a suite of standards on well casing, well depth, wastewater storage, and similar elements (Richardson et al., 2013). One well-known problem with relying on technology standards is that implementation may vary considerably across firms. For this industry, many firms are engaged in extraction of unconventional natural gas, and they are of varying sizes and degrees of technical capability (Small et al., 2014). Moreover, with technology standards, the regulator will not necessarily observe whether the technology is correctly

[43]See, for instance, Federal Register Volume 79 Number 125, "Petroleum Refinery Sector Risk and Technology Review and New Source Performance Standards; Proposed Rule," June 30 2014; accessed from http://www.gpo.gov/fdsys/pkg/FR-2014-06-30/pdf/2014-12167.pdf.

installed. This issue is important for both methane leaks and well casings, which are a function of equipment integrity.

The academic literature in environmental economics has proposed a set of regulations that are incentive compatible even under imperfect attribution. First proposed by Segerson (1988), the approach combines *ambient* environmental quality standards with joint liability. For instance, if regulators can observe groundwater quality throughout a geographic area, they hold all firms in that area liable for any damages to the water. Not surprisingly, despite a large theoretical literature, legal and political barriers have prevented this approach from being implemented.

One could imagine, however, a version of the Segerson (1988) approach being applied to unconventional natural gas extraction. This variant allows firms to opt out of the penalties if they can prove, with their own (regulator-verified) monitoring devices, that they did not contribute to the damages (Millock, Sunding and Zilberman, 2002).[44] This approach leverages self-selection of clean firms into self-monitoring. One could imagine clean, technologically advanced firms agreeing to this sort of solution for groundwater emissions, surface water emissions, and methane leaks in order to prevent a total ban on fracking activities.

In conclusion, scientists remain concerned about a number of environmental damages caused by fracking. Unfortunately, data collection has not kept pace with the boom in extraction, and a great deal of uncertainty remains regarding pollution from fracking. This has limited the ability of regulators to target those areas of greatest concern; it has also limited their ability to regulate in a cost-effective way. Higher quality, comprehensive data on baseline levels of environmental quality as well as on emissions from individual producers would go a long way. In the absence of such data, regulatory options remain limited and are unlikely to be cost effective.

7 Conclusion

This paper provides what we believe to be the most comprehensive analysis to date of how shale gas development has affected the welfare of U.S. consumers and producers of natural gas. We estimate both the demand and supply curves for natural gas and then use these estimates to find that the expansion of natural gas supply has reduced U.S. natural gas prices by $3.45 per mcf from 2007 to 2013, equivalent to 47% of the counterfactual 2013 price. This price reduction has led to large increases in surplus for natural gas consumers, particularly in the South Central and Midwestern United States where the industrial and electric power

[44] Recently enacted legislation in North Carolina does involve presumptive liability for water contamination, placing the burden of proof on the gas developer or operator.

sectors consume large quantities of gas. We confirm that the wholesale natural gas price reduction has fully passed through to retail rates for all sectors. However, pass-through of industrial gas prices to prices for gas-intensive manufactured products need not be 100%. For ammonia and HDPE, two commodity chemicals with gas-intensive production processes, we show that U.S. and international output prices are tightly linked even though natural gas input prices have diverged, suggesting that pass-through is very small.

In contrast to natural gas consumers, we find that natural gas producers have experienced a reduction in surplus because their gain from the expansion of supply has been outweighed by the fall in the gas price. These surplus reductions are particularly acute in regions that have historically produced large quantities of conventional natural gas but have not developed shale resources. Combining our consumer and producer surplus estimates, we estimate that the shale boom has increased total U.S. consumer plus producer surplus by $48 billion annually. Under plausible alternative assumptions, this number varies by up to 20 percent. Currently planned levels of LNG exports will further increase U.S. total surplus, but the gains will be modest because the increase in producer surplus will be shared with Canadian exporters to the United States.

Importantly, our consumer and producer surplus estimates omit changes in welfare associated with environmental externalities from shale gas development. We provide a summary of the potential local and global environmental impacts from the fracking revolution, noting that for the vast majority of these impacts the data necessary to obtain an economic valuation do not exist. Plausible bounds on the climate impacts for 2013 range from a 0.7 billion dollar annual reduction in external costs to a 27 billion dollar annual increase in external costs; bounding local damages is not possible. It is therefore impossible to know, at present, the extent to which environmental externalities offset the net welfare gains to natural gas consumers and producers. Improvements in data collection would be immensely valuable both for quantifying potential environmental impacts from fracking and for enabling cost-effective regulation.

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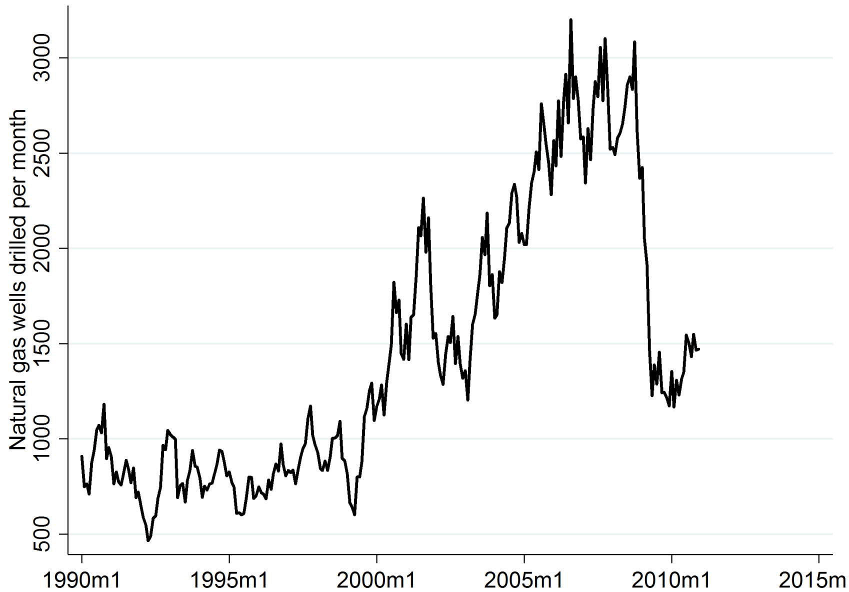
Appendix

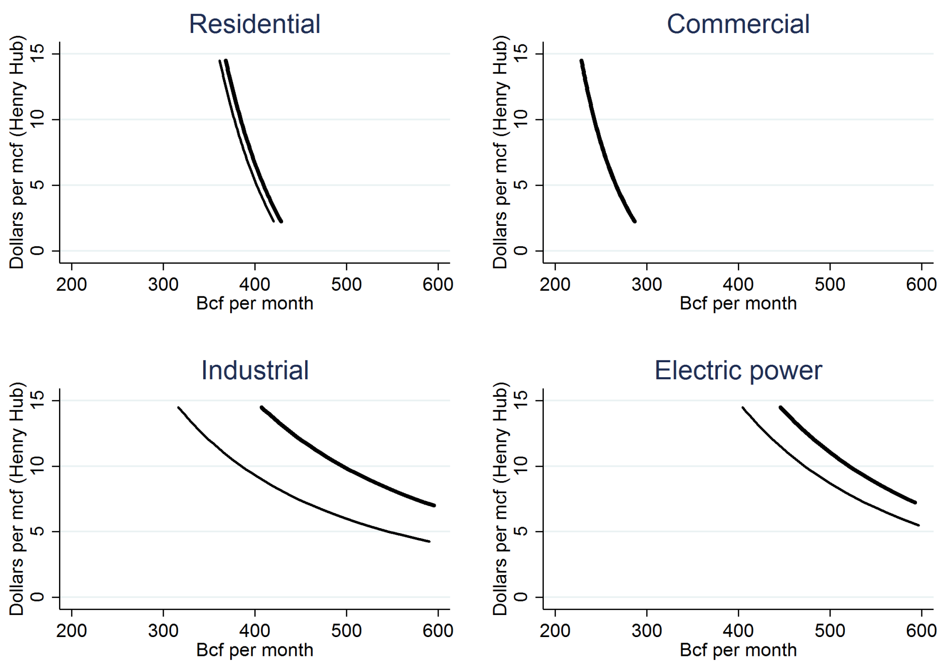
A1.1 Supplementary figures and tables

Figure A1: U.S. Natural Gas Drilling



Note: Wells include both development and exploratory wells. Wells producing both oil and natural gas are excluded. Source: EIA.

Figure A2: Estimated Demand Shift, 2007 to 2013, by Sector



Note: The thin lines show 2007, and thick lines 2013. We assume that supply and demand are constant elasticity (at the sectoral level) over the range of the data, with elasticities given by the estimates in table 1. We back out the scale parameters for the demand and supply curves for each year using observed prices and quantities.

Table A1: Potential Demand Shifters

	2007	2013	% change
Panel A: Impacts to All End-Uses			
Real GDP, trillions	15.9	16.8	5.6%
Population, millions (all regions)	301	316	5.1%
Real median income (all regions)	56,000	52,000	-8.0%
Panel B: Impacts to Residential (Heating) Only			
Heating degree days, daily (population weighted)	11.5	12.1	5.1%
Population, millions (cold states)	120	124	3.0%
Real median income (cold states)	59,000	56,000	-4.2%
Panel C: Impacts to Industrial Only			
Employment, non-gas intensive industries, millions	7.0	5.8	-17%
Establishments, non-gas intensive industries, thousands	192	168	-12%
Panel D: Impacts to Electricity Only			
Cooling degree days, daily (population weighted)	3.8	3.6	-4.9%
Population, millions (hot states)	178	190	6.4%
Real median income (hot states)	53,000	49,000	-9.2%
Electricity generation, billion MWhs: total	4.2	4.1	-2.4%
Fossil fuels	3.0	2.7	-8.4%

Note: This table reports changes to potential demand shifters for natural gas. GDP is in trillions of 2013 dollars. Median income (household) is in 2013 dollars. Hot states are the 24 warmest, as measured by average HDDs for 1981-2013; cold states are the 24 coldest (as described in the text, Alaska and Hawaii are dropped). Non-gas-intensive industries are those with gas intensity below the (weighted) median, according to the 2007 BEA input-output tables. We present only the trends for non-gas-intensive industries, so as not to confound with the impact of the natural gas price fall.

Table A2: First Stage: Demand

	Residential	Commercial	Industrial	Electric power
Cumulative other HDDs, hundreds	0.47	0.56	0.75	0.89
	(0.14)	(0.17)	(0.23)	(0.26)
Own HDDs, hundreds	-0.78	-0.47	-0.22	-0.51
	(0.44)	(0.48)	(0.59)	(0.66)
Own CDDs, hundreds	-0.52	-1.16	-1.76	-1.44
	(0.56)	(0.74)	(1.13)	(1.18)
Lagged demand	-0.23	-0.25	-0.07	0.01
	(0.05)	(0.07)	(0.04)	(0.02)
Observations	6912	6912	6912	6849

Note: This table reports first stage estimates for the 2SLS estimates presented in table 1. The dependent variable is retail price in each sector in logs. The excluded instrument in the second stage is cumulative other heating degree days (HDDs). As described in the text, the instrument is constructed with lags 2 through 12. The time period covered is 2002-2013. All specifications include month by state fixed effects, a linear time trend, and lagged cooling and heating degree days. Standard errors are two-way clustered by sample month and state.

Table A3: First Stage: Supply

	Henry Hub price
Lagged HDDs, hundreds	4.46
	(2.33)
Lagged CDDs, hundreds	6.79
	(3.82)
Current HDDs, hundreds	3.52
	(1.96)
Current CDDs, hundreds	2.69
	(2.78)
Lagged supply	0.94
	(0.14)
Observations	108

Note: This table reports first stage estimates for the 2SLS estimates presented in table 1. The dependent variable is the Henry Hub price in logs. The excluded instruments in the second stage are one-month lagged heating and cooling degree days. The time period covered is 2002-2010. Month effects and a linear time trend are included. Standard errors are HAC robust.

Table A4: Alternative Instruments: Demand

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
				Panel A: Residential			
log(Price)	-0.14	-0.10	-0.15	-0.14	-0.12	-0.37	-0.13
	(0.12)	(0.12)	(0.12)	(0.14)	(0.11)	(0.17)	(0.11)
y_{t-1}	0.42	0.43	0.42	0.42	0.43	0.38	0.43
	(0.05)	(0.05)	(0.05)	(0.05)	(0.04)	(0.05)	(0.04)
Long-run price	-0.25	-0.18	-0.25	-0.25	-0.22	-0.59	-0.22
	(0.20)	(0.21)	(0.19)	(0.23)	(0.18)	(0.24)	(0.18)
First-stage F	8.86	8.84	0.97	7.32	6.93	7.00	11.20
				Panel B: Commercial			
log(Price)	-0.13	-0.08	-0.11	-0.11	-0.10	-0.27	-0.13
	(0.08)	(0.08)	(0.08)	(0.11)	(0.07)	(0.12)	(0.07)
y_{t-1}	0.58	0.59	0.58	0.58	0.59	0.54	0.58
	(0.04)	(0.04)	(0.04)	(0.05)	(0.04)	(0.04)	(0.04)
Long-run price	-0.30	-0.20	-0.26	-0.26	-0.23	-0.60	-0.31
	(0.18)	(0.19)	(0.17)	(0.25)	(0.17)	(0.22)	(0.16)
First-stage F	9.81	9.08	0.96	4.45	6.17	7.13	11.19
				Panel C: Industrial			
log(Price)	-0.15	-0.15	-0.17	-0.16	-0.16	-0.20	-0.19
	(0.07)	(0.07)	(0.07)	(0.13)	(0.07)	(0.19)	(0.09)
y_{t-1}	0.72	0.72	0.72	0.72	0.72	0.72	0.72
	(0.09)	(0.09)	(0.09)	(0.09)	(0.09)	(0.10)	(0.09)
Long-run price	-0.55	-0.54	-0.61	-0.58	-0.57	-0.71	-0.66
	(0.16)	(0.18)	(0.19)	(0.39)	(0.17)	(0.47)	(0.21)
First-stage F	10.12	8.37	0.97	2.89	5.65	4.24	10.62
				Panel D: Electric Power			
log(Price)	-0.15	-0.26	-0.23	-0.02	-0.14	-0.40	-0.26
	(0.14)	(0.18)	(0.16)	(0.32)	(0.14)	(0.33)	(0.18)
y_{t-1}	0.68	0.68	0.68	0.68	0.68	0.68	0.68
	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)
Long-run price	-0.46	-0.80	-0.71	-0.07	-0.45	-1.24	-0.79
	(0.41)	(0.55)	(0.47)	(0.99)	(0.43)	(0.98)	(0.54)
First-stage F	11.6	8.79	1.16	3.06	6.44	5.10	13.34
Instruments:							
Shorter cumulative HDDs	Y						
Longer cumulative HDDs		Y					
All lags of HDDs			Y				
Cumulative CDDs				Y	Y		
Cumulative HDDs					Y		
Local HDDs						Y	
East/West HDDs							Y

Note: This table reports 2SLS price elasticity estimates for U.S. natural gas demand. The dependent variable is quantity consumed, in logs. The cumulative heating and cooling degree days (HDDs and CDDs) IVs use data from other regions and lags 2 through 12. The "shorter" IV uses lags 2 through 11, and the "longer" IV uses lags 2 through 13. The "all lags" IV uses multiple IVs (lags 2 through 12) rather than a single cumulative IV. The "local" IV uses only weather in the own state. The "East/West" IV uses weather only in the own half of the country (with census region "West" versus all other census regions) and excludes own-division weather. The time period covered is 2002-2013, so there are 6912 observations in each specification; missing values for the electricity specifications lead to 6849 observations. Standard errors are two-way clustered by sample month and state.

Table A5: Alternative Controls: Demand

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
				Panel A: Residential			
log(Price)	-0.11	-0.07	-0.20	-0.08	-0.11	0.05	-0.10
	(0.11)	(0.11)	(0.29)	(0.29)	(0.12)	(0.13)	(0.12)
Long-run price	-0.19	-0.13	-0.41	-0.14	-0.17	0.09	-0.20
	(0.19)	(0.20)	(0.56)	(0.50)	(0.18)	(0.25)	(0.23)
First-stage F	9.99	12.62	6.91	6.20	10.12	7.66	9.64
				Panel B: Commercial			
log(Price)	-0.12	-0.11	-0.07	<0.01	-0.10	0.02	-0.07
	(0.08)	(0.07)	(0.22)	(0.19)	(0.08)	(0.08)	(0.08)
Long-run price	-0.25	-0.28	-0.20	<0.01	-0.22	0.04	-0.20
	(0.15)	(0.16)	(0.58)	(0.47)	(0.16)	(0.21)	(0.24)
First-stage F	10.99	15.87	14.87	14.56	10.7	8.36	9.78
				Panel C: Industrial			
log(Price)	-0.17	-0.16	-0.05	-0.01	-0.18	-0.14	-0.10
	(0.07)	(0.07)	(0.05)	(0.04)	(0.08)	(0.04)	(0.04)
Long-run price	-0.59	-0.56	-0.19	-0.05	-0.55	-0.50	-0.62
	(0.17)	(0.16)	(0.18)	(0.14)	(0.17)	(0.21)	(0.19)
First-stage F	10.81	14.29	27.10	27.21	10.05	11.56	9.38
				Panel D: Electric Power			
log(Price)	-0.15	-0.24	0.20	0.35	-0.17	-0.04	-0.05
	(0.17)	(0.15)	(0.57)	(0.57)	(0.15)	(0.14)	(0.13)
Long-run price	-0.44	-0.84	0.60	1.07	-0.50	-0.12	-0.19
	(0.49)	(0.48)	(1.75)	(1.81)	(0.42)	(0.44)	(0.48)
First-stage F	12.19	15.66	5.52	6.31	12.04	12.66	11.18
Controls:							
Lagged HDDs and CDDs		Y	Y	Y	Y	Y	Y
State by month effects	Y	Y		Y	Y	Y	Y
Census division by month effects			Y				
Linear time trend	Y				Y	Y	
Year effects			Y	Y			
Time trend by census division					Y		
Cumulative local HDDs						Y	
y_{t-2}							Y

Note: This table reports 2SLS price elasticity estimates for U.S. natural gas demand. The dependent variable is quantity consumed, in logs. The specifications are identical to those in table 1 except for the controls. There are 6,912 observations in the residential, commercial, and industrial equations, and 6,849 observations in the electric power equations.

Table A6: Alternative Instruments: Supply

	(1)	(2)	(3)	(4)	(5)
log(Price)	0.07	0.10	0.06	0.13	0.11
	(0.04)	(0.04)	(0.04)	(0.05)	(0.04)
y_{t-1}	0.91	0.88	0.91	0.85	0.87
	(0.04)	(0.04)	(0.04)	(0.04)	(0.03)
Long-run price	0.75	0.84	0.72	0.88	0.85
	(0.16)	(0.14)	(0.22)	(0.14)	(0.14)
First-stage F	2.33	4.50	3.22	13.32	9.53
Instruments:					
One-month lagged HDDs	Y	Y	Y	Y	Y
One-month lagged CDDs	Y	Y	Y	Y	Y
Cumulative HDDs	Y				
Cumulative CDDs	Y				
Lagged Henry Hub price		Y			Y
Lagged demand			Y		Y
Lagged oil wells				Y	Y

Note: This table reports 2SLS price elasticity estimates for U.S. natural gas supply. The dependent variable is quantity supplied, in logs. The lag length for Henry Hub price, quantity demanded, and oil wells drilled is six months. Total quantity demanded is the sum of residential, commercial, industrial, and electric power natural gas demand in all states. The time period covered is 2002-2010, so there are 108 observations in each specification. Month effects and a linear time trend and current population-weighted HDDs and CDDs are included. Standard errors are HAC robust.

Table A7: Alternative Controls: Supply

	(1)	(2)	(3)	(4)	(5)
log(Price)	0.10	0.09	0.05	0.05	0.09
	(0.05)	(0.05)	(0.07)	(0.06)	(0.05)
y_{t-1}	0.89	0.89	0.77	0.93	0.78
	(0.04)	(0.04)	(0.06)	(0.05)	(0.16)
y_{t-2}					0.11
					(0.14)
Long-run price	0.88	0.81	0.23	0.66	0.83
	(0.18)	(0.16)	(0.30)	(0.42)	(0.17)
First-stage F	4.09	4.37	6.50	3.76	4.54
Controls:					
HDDs and CDDs		Y	Y	Y	Y
Month effects	Y	Y	Y	Y	Y
Linear trend	Y			Y	Y
Year effects			Y		
Monthly linear trends				Y	

Note: This table reports 2SLS price elasticity estimates for U.S. natural gas supply. The dependent variable is quantity supplied, in logs. The specifications are identical to those in table 1 except for the controls. There are 108 observations.

Table A8: Pass-Through of Henry Hub to Retail Natural Gas Prices, Full Results

	Residential	Commercial	Industrial	Electric power
Henry Hub price$_t$	0.10	0.11	0.16	0.31
	(0.03)	(0.02)	(0.02)	(0.04)
Henry Hub price$_{t-1}$	0.27	0.26	0.26	0.25
	(0.03)	(0.02)	(0.03)	(0.05)
Henry Hub price$_{t-2}$	-0.13	-0.14	-0.16	-0.36
	(0.03)	(0.02)	(0.03)	(0.06)
Henry Hub price$_{t-3}$	-0.04	-0.04	-0.07	-0.01
	(0.03)	(0.02)	(0.02)	(0.04)
Henry Hub price$_{t-4}$	0.00	-0.02	0.03	0.04
	(0.03)	(0.02)	(0.02)	(0.04)
Henry Hub price$_{t-5}$	-0.01	-0.01	-0.02	-0.04
	(0.03)	(0.02)	(0.02)	(0.03)
Henry Hub price$_{t-6}$	0.02	0.02	0.04	0.10
	(0.04)	(0.02)	(0.02)	(0.04)
Henry Hub price$_{t-7}$	0.00	0.00	-0.02	-0.04
	(0.04)	(0.02)	(0.02)	(0.03)
Henry Hub price$_{t-8}$	0.04	0.03	0.01	0.03
	(0.04)	(0.02)	(0.02)	(0.03)
Henry Hub price$_{t-9}$	-0.02	-0.03	0.00	-0.02
	(0.05)	(0.02)	(0.02)	(0.03)
Henry Hub price$_{t-10}$	-0.01	0.00	-0.02	-0.02
	(0.04)	(0.02)	(0.02)	(0.04)
Henry Hub price$_{t-11}$	0.03	0.03	0.04	0.04
	(0.04)	(0.02)	(0.02)	(0.04)
y_{t-1}	0.77	0.81	0.73	0.71
	(0.02)	(0.02)	(0.02)	(0.02)
Observations	6912	6912	6912	6912
Implied long-run price	1.18	1.08	1.00	0.94
	(0.19)	(0.11)	(0.08)	(0.12)

Note: Data are monthly from 2002 to 2013, and are at the state level. The dependent variable is the sector-level retail price, in levels. As described in the text, the electric power price we use is the citygate price. The long-run price elasticity is calculated as the sum of the coefficients on prices with lags zero through eleven, divided by (one minus the coefficient on y_{t-1}). All specifications control for year effects and state by month effects. Standard errors are clustered by sample month.

Table A9: Pass-Through of Henry Hub to Retail Natural Gas Prices, 2SLS Specification

	Residential	Commercial	Industrial	Electric power
Henry Hub price$_t$	0.23	0.29	0.33	0.64
	(0.08)	(0.06)	(0.07)	(0.14)
y_{t-1}	0.77	0.72	0.67	0.38
	(0.05)	(0.05)	(0.05)	(0.11)
Observations	6912	6912	6912	6912
Implied long-run price	0.99	1.03	0.99	1.02
	(0.14)	(0.07)	(0.08)	(0.06)
First-stage F	5.56	8.31	8.10	5.17

Note: Data are monthly from 2002 to 2013, and are at the state level. The dependent variable is the sector-level retail price, in levels. As described in the text, the electric power price we use is the citygate price. The long-run price elasticity is calculated as the coefficient on the Henry Hub price, divided by (one minus the coefficient on y_{t-1}). The instruments for the price variable are population-weighted lagged national heating degree days and cooling degree days. All specifications control for current and one-month lagged own-state HDDs and CDDs, state by month effects, and a linear time trend. Standard errors are two-way clustered by sample month and state.

Table A10: Employment Regressions

	(1)	(2)	(3)	(4)
Gas intensity	1.25	0.93	1.00	1.45
	(0.77)	(0.70)	(0.67)	(1.12)
Log employment, 2002	-0.32	-0.42	-0.42	-0.32
	(0.06)	(0.06)	(0.06)	(0.07)
Log employment, 2007	1.31	1.39	1.39	1.31
	(0.06)	(0.06)	(0.06)	(0.07)
Constant	-0.03	0.15	0.17	0.03
	(0.14)	(0.14)	(0.14)	(0.15)
NAICS-2 effects		Y		
NAICS-3 effects	Y			Y
Weighting by output	Y	Y	Y	
Weighting by 2007 employment				Y
Observations	229	229	229	229

Note: Data are at the 6-digit NAICS level and represent the manufacturing industry (NAICS 31-33). The dependent variable is log employment in 2012.

A1.2 Climate Change Impacts Calculations

Here we give the parameters assumed for the calculations in section 6.1. In our estimated counterfactual, quantity produced increases by 6173 bcf/year and quantity consumed increases by 4132 bcf/month; the difference comes from a reduction in net imports. For our "high" case, we use 6173, and for our "low" case, we use 4132. Of the 4132 bcf/month, 2441 is in the residential, commercial and industrial sectors; 1691 is in the electric power sector.

Parameters

- Heat content of natural gas: 1.025 mmBtu per mcf.[45]
- Carbon content of fuels: 117.08 pounds CO_2 per mmBtu for natural gas and 212.7 pounds CO_2 per mmBtu for coal.[46]
- Social cost of carbon: 39 \$(2011)/metric ton, or 40 \$(2013)/metric ton. Source: Interagency Working Group on Social Cost of Carbon, United States Government.[47]
- Gross methane leak rate: 0.42% (low case) to 7.9% (high case).[48]
- Mass of methane in one bcf of dry gas (1,100 Btu/cf) at standard temperature and pressure: 20,602 metric tons per bcf.[49]
- Methane global warming potential, 100-year (GWP): 34.[50]
- Average heat rate of power plants: 10416 Btu per kWh for natural gas and 10107 Btu per kWh for coal.[51]

High Case Calculations

- High case: increase in CO_2 emissions from increased combustion of natural gas:

$$= \frac{6173\text{bcf}}{\text{year}} \cdot \frac{1025 \cdot 10^9\text{Btu}}{\text{bcf}} \cdot \frac{117.08 \cdot 10^3 \text{ lbs } CO_2}{10^9 \text{ Btu}} \cdot \frac{\text{ton}}{2205 \text{ lbs}} \cdot \frac{40\$}{\text{ton } CO_2}$$

$= +13$ billion dollars per year

[45] http://www.eia.gov/tools/faqs/faq.cfm?id=45&t=8

[46] http://www.eia.gov/tools/faqs/faq.cfm?id=74&t=11

[47] http://www.epa.gov/climatechange/EPAactivities/economics/scc.html

[48] Low case: (Allen et al., 2013). High case: (Howarth, 2014).

[49] http://agnatural.pt/documentos/ver/natural-gas-conversion-pocketbook_fec0aeed1d2e6a84b27445ef096963a7eebab0a2.pdf. Calculations: 1 metric ton of LNG = 1300 cubic meters of gas at normal temperature and pressure, where dry gas is 1,163 Btu/cf. Thus, 1 metric ton equals 1300 * 35.315 cf/cm * 1163 / 1100 = 48,538 cf of dry gas at STP. Inverting yields 20,602 metric tons of gas per bcf.

[50] http://www.climatechange2013.org/images/report/WG1AR5_Chapter08_FINAL.pdf

[51] http://www.eia.gov/tools/faqs/faq.cfm?id=74&t=11

- High case: increase in methane emissions from increased extraction of natural gas:

$$= \frac{6173 \text{ bcf}}{\text{year}} \cdot \frac{0.079}{1 - 0.079} \cdot \frac{20602 \text{ tons}}{\text{bcf}} \cdot 34 \text{ GWP} \cdot \frac{40\$}{\text{ton}}$$

  = +15 billion dollars per year

- Total, high case: +28 billion dollars per year

Low Case Calculations

- Low case: increase in CO_2 emissions from increased combustion in residential, commercial and industrial sectors:

$$= \frac{2441 \text{ bcf}}{\text{year}} \cdot \frac{1025 \cdot 10^9 \text{ Btu}}{\text{bcf}} \cdot \frac{117.08 \cdot 10^3 \text{ lbs CO}_2}{10^9 \text{ Btu}} \cdot \frac{\text{ton}}{2205 \text{ lbs}} \cdot \frac{40\$}{\text{ton}}$$

  = +5.3 billion dollars per year

- Low case: decrease in CO_2 emissions from displaced coal in electric power sector:

$$= \frac{1691 \text{ bcf}}{\text{year}} \cdot \frac{1025 \cdot 10^3 \text{ mmBtu}}{\text{bcf}} \cdot \frac{\text{kWh}}{10416 \text{ Btu(gas)}} \cdot \frac{10107 \text{ Btu(coal)}}{\text{kWh}} \cdot \frac{212.7 \text{ lbs CO}_2}{\text{mmBtu(coal)}} \cdot \frac{\text{tons}}{2205 \text{ lbs}} \cdot \frac{40\$}{\text{ton}}$$

  = -6.5 billion dollars per year

- Low case: increase in methane emissions from increased extraction of natural gas:

$$= \frac{4132 \text{ bcf}}{\text{year}} \cdot \frac{0.0042}{1 - 0.0042} \cdot \frac{20602 \text{ tons}}{\text{bcf}} \cdot 34 \text{ GWP} \cdot \frac{40\$}{\text{ton}}$$

  = +0.5 billion dollars per year

- Total, low case: -0.7 billion dollars per year