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The effects of combined-cycle generation and hydraulic fracturing on the price for coal, oil, and natural gas: Implications for carbon taxes

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ABSTRACT

We identify how the increased efficiency of generating electricity using gas-fired combined-cycle technology and the increased production of natural gas due to hydraulic fracturing in the US affect the first purchase price for coal, oil, and natural gas and their prices at electricity generating plants by estimating a cointegrating vector autoregression model from monthly observations between January 1991 and February 2016. Simulation experiments indicate that combined-cycle generation raises the long-run price of natural gas, both at the wellhead and electricity generating plants. Conversely, the increased production of natural gas has a relatively small long-run effect on natural gas prices. Historical counterfactuals indicate increased natural gas production since June 2003 lowers natural gas prices by an average of $0.16 per million BTU while combined cycle generation increases prices by an average of $0.54 per million BTU since April 1999. This increase is captured by natural gas producers such that the margin between prices at electricity generating plants and the wellhead shrinks by about $0.05 per million BTU. This analysis suggests that market relations among energy prices and their statistical ordering will reinforce the direct effects of a carbon tax on relative prices in ways that enhance interfuel substitution towards natural gas.

1. Introduction

Coal, oil, and natural gas are used to power economic activity. Much of this power is provided in the form of process heat. The amount of process heat generated depends on a fuel's energy content, which is measured in BTU or kcals. Using coal, oil, and natural gas as a source for process heat implies that their prices should be related because factors of production generally are priced according to their value marginal product.

But a relation among fossil fuel prices based on their value marginal product does not mean that the price for a heat unit should be the same across fuels (Adelman and Watkins, 1997; Smith, 2004). Historically, the price for a barrel of WTI is about ten times greater than a thousand cubic feet of natural gas at the Henry Hub (Hartley et al., 2008). Price differences are caused by differences in energy density (energy per unit mass) and the efficiency of the capital stock that coverts a fuel to useful work. For many applications, a heat unit of coal generates less useful work than a heat unit of oil or natural gas (Adams and Miovic, 1968; Cleveland et al., 1984, 2000; Kaufmann, 1992). Differences in marginal product mean that a heat unit of coal generally is priced lower than a heat unit of oil and natural gas (Kaufmann, 1994).

Although prices per heat unit vary among fuels, many analyses find that oil and gas prices cointegrate (Bachmeier and Griffin, 2006; Brown and Yucel, 2008; Hartley et al., 2008; Kaufmann et al., 2009; Ramberg and Parsons, 2012; Serletis and Herbert, 1999; Villar and Joutz, 2006). Cointegration implies that the prices for oil and natural gas move together such that they return to a long-run equilibrium after being disturbed.

Despite findings of cointegration, price ratios among fossil fuels change over time. By the early 2000's, the 'rule of thumb' for the ratio for the price of a barrel of WTI to a million BTU of natural gas at Henry Hub dropped from historic levels of about 10:1 to a ratio of 6:1 (Hartley et al., 2008). This change may be caused by oil and natural gas prices 'decoupling' (Erdos, 2012; Serletis and Rangel_Ruiz, 2004; Serletis and Herbert, 1999), but this seems unlikely given the possibility for interfuel substitution.

Instead, long-run cointegrating relations among fossil fuel prices may be altered by technical, legislative, or trade-related changes that alter the value marginal product of coal, oil, and/or natural gas. For example, legislation aimed at reducing acid deposition increases the costs of burning coal or oil relative to natural gas because natural gas emits less sulfur oxides per heat unit. Based on these effects, legislation

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aimed at reducing acid deposition tends to lower the price of fuels with a high sulfur content (Kohli and Morey, 1990; Wang, 2003). Similarly, combined-cycle technology increases the efficiency of generating electricity from natural gas relative to coal and oil (Hartley et al., 2008). This increases the value marginal product of natural gas relative to coal and oil, which raises the price of natural gas relative to coal and oil at electricity generating plants (Hartley et al., 2008). Yet other analyses emphasize that oil is traded internationally while natural gas produced in the US is consumed largely in the US, and so their relative prices are affected by nominal exchange rates (Hartley and Medlock, 2014).

To capture the effects of legislative, technical, and/or economic factors on relative prices, some analyses allow for a structural change or a break in the cointegrating relation between energy prices. Ramberg and Parsons (2012) find that the cointegrating relation between the wellhead price for oil and natural gas changes in 2006 and again in 2009. Using a Markov switching model, Brigida (2014) finds that the ratio of wellhead prices for crude oil and natural gas alternates between two regimes; switching from a regime of high oil prices relative to natural gas prices to a regime of lower oil prices in August 2000 and back to the higher oil price regime in May 2009. Based on these results, the literature suggests that prices for crude oil and natural gas do not decouple; their long-run equilibrium relation changes.

But this conclusion begs the question, why does the long-run equilibrium relation between the price of oil and natural gas change? Ramberg and Parsons (2012) do not explain why the cointegrating relation between the wellhead price for oil and natural gas changes in 2006 and again in 2009. Similarly, Brigida (2014) does not explain why the relative price of crude oil and natural gas changes in August 2000 and even more curiously, why it changes back to the original relation in May 2009.

To identify why relative prices change, we expand the approach pioneered by Hartley et al. (2008), who specify a model that explicitly represents a variable that they postulate changes the price of oil relative to natural gas; the efficiency of combined cycle generating technology. We expand this approach in three ways: (1) by expanding the technical variables postulated to influence prices, (2) by expanding the vector of energies examined to include coal, and (3) by expanding the vector of prices to include downstream prices. Specifically, our model proxies two technical changes in the natural gas market: combined cycle generation and hydraulic fracturing. Combined-cycle technology increases the efficiency of generating electricity from natural gas by about 25%. In 2015, combined cycle technology burned 7655 BTU of natural gas to generate a kilowatt hour of electricity compared to the 10,372 BTU of gas (or 10,059 BTU of coal) burned by steam generation (https://www.eia.gov/electricity/annual/html/epa_08_02.html). The combination of hydraulic fracturing and horizontal drilling is largely responsible for the recent increase in natural gas production, which rises from 23.5 billion cubic feet in 2006 to nearly 33 billion cubic feet in 2015, after fluctuating between 19 and 24 billion cubic feet between 1970 and 2005 (https://www.eia.gov/totalenergy/data/monthly/pdf/Sections 4_3.pdf). We include coal prices because coal competes with natural gas in several markets, including the electricity-generating sector (Hartley et al., 2008). This competition is represented explicitly by including the price for coal, oil, and natural gas paid by electricity generating plants.

To identify how technical changes in the natural gas market are related to first purchase prices for coal, oil, and natural gas and their prices at electricity generating plants, we use monthly observations between January 1991 and February 2016 to estimate a cointegrating vector autoregression (CVAR) model. Results indicate that the wellhead prices for coal and oil, the efficiency of gas fired electricity generation, and the domestic production of natural gas are weakly exogenous and can account for persistent movements in the wellhead price for natural gas and the price for coal, oil, and natural gas at electricity generating plants. Model simulations indicate that the increased efficiency of combined cycle generation raises the long-run price of natural gas, both at the wellhead and at electricity generating plants. Surprisingly, increased production of natural gas has a relatively small long-run effect on natural gas prices. We postulate that increased production lowers natural gas prices in the short-run, which increases long-run consumption, which eventually raises prices. These effects are mirrored in historical counterfactuals, which indicate that increased natural gas production since February 2006 lowers natural gas prices by an average of $0.16 per million BTU while combined cycle generation increases the price of natural gas by an average of $0.54 per million BTU since August 2000. All of this increase and more is captured by natural gas producers such that the margin between prices at electricity generating plants and the wellhead shrinks by about $0.05 per million BTU.

These results and the methods used to obtain them are described in five sections. The next section describes the data and the statistical methodology used to estimate the CVAR model. The third section describes the statistical results. The cointegrating relations and experiments that are designed to quantify the long- and short-run effect of changes in natural gas technologies and the first purchase price for crude oil and coal are described in the fourth section. The final section concludes by describing how the market relations among fossil fuel prices quantified by the CVAR model re-inforce the short-run price changes generated by a carbon tax in ways that enhance the quantity of carbon abated by interfuel substitution.

2. Methodology

2.1. Data

We compile monthly data for observations of the US first purchase price for coal, oil, natural gas, their price at electricity generating plants, the quantities consumed by electric utilities, the net quantity of electricity generated, the quantity of natural gas produced, and weather (Table 1). We focus on the US market because natural gas transportation networks and the electrical grid largely separate these US markets from much of the rest of the world. We do not include the price of fuels derived from biomass to generate electricity because this source only powered about 1.5% of the electricity generated in the US in 2016, compared to fossil fuels, which generated about 65% (https://www.eia.gov/tools/faqs/faq.php?id=427&t=3). The small fraction associated with biomass fuels implies that the price of these fuels likely have a small effect on the price of fossil fuels purchased by the electricity generating plants; instead the price of fossil fuels more likely drives changes in the price of fuels generated from biomass. Finally, we do not explicitly consider environmental costs not already included in purchase prices. For example, the price of coal at electricity power plants includes the cost of complying with legislation aimed at reducing acid deposition, but does not include the effect of coal on climate.

First purchase prices include the export price for Australian thermal coal *MineMouth*, (12,000- BTU/pound, less than 1% sulfur, 14% ash, FOB Newcastle/Port Kembla, US$ per metric ton), the spot price for natural gas at the Henry Hub, *HenHub* (Dollars per million BTU),[2] and the domestic first purchase price for crude oil *PCrude* (Dollars per barrel, EIA). We use an international price for coal, which represents a price against which all coals must compete, to avoid idiosyncrasies associated with local prices for coal, which can vary significantly across the US. All prices are converted to US dollars per million BTU. Downstream prices include the price of coal *PCoal*, natural gas *PGas*, and residual fuel oil *POil* at electric generating plants (nominal dollars per million BTU, including taxes). All prices are deflated by monthly values of the U.S. city average for all items (CUUR0000SA0).

Monthly data for electric generating plants include the quantity of coal used to generate electricity *FireCoal* (thousand short tons), the quantity of natural gas used to generate electricity *FireGas* (billion cubic feet), and the quantity of oil used to generate electricity *FireOil*

[2] The EIA discontinued the time series for well head price for natural gas.