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Fuel cost uncertainty, capacity investment and price in a competitive electricity market

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ABSTRACT

This paper studies the effect of natural-gas fuel cost uncertainty on capacity investment and price in a competitive electricity market. Our model has a two-stage decision process. In the first stage, an independent power producer (IPP) builds its optimal capacity, conditional on its perceived uncertainties in fuel cost and electricity demand. In the second stage, equilibrium prices and quantities are determined by IPPs competing in a Cournot market. Under the empirically reasonable assumption that per MWh fuel costs are log-normally distributed, we find that a profit-maximizing IPP increases its capacity in response to rising fuel cost volatility. Consequently, the expected profit of the IPP and expected consumer surplus increase with volatility, rejecting the hypothesis that rising fuel cost uncertainty tends to adversely affect producers and consumers. Expected consumer surplus further increases if the IPP hedges the fuel cost risk. However, the IPP's optimal strategy is not to do so. The policy implication of these results is that the government should not intervene to reduce the price volatility of a well-functioning spot market for natural gas, chiefly because such intervention can have the unintended consequence of discouraging generation investment, raising electricity prices, and harming consumers.

1. Introduction

Over the past three decades, the electricity sector in many countries has transitioned from an integrated monopoly to one with a deregulated generation market in which electricity prices and capacity investments reflect the decentralized decision making of independent power producers (IPPs) (Newbery, 1995, 2002, 2005; Joskow, 2006, 2008; Shively and Ferrare, 2010). An IPP's capacity investment is based on an assessment of expected future profits. Thus, the introduction of market competition exposes the IPP to risks previously borne by retail end-users under a regulated monopoly's cost of service ratemaking.

Large-scale natural gas developments (e.g., shale gas in the USA) have caused a price decline that encourages the use of natural gas in electricity generation. Relative to coal-fired generation, natural-gas-fired generation has less emissions and shorter construction periods (MIT, 2011). It is dispatchable in real time, offering operational flexibility for reliable grid integration of intermittent renewable resources. As a result, nearly all new plants in the USA are fueled by natural gas (DECC, 2012; EIA, 2013).

Natural-gas-fired generation faces large fuel cost risks because: (a) natural gas constitutes about 80% of its variable costs, and (b) natural gas has large price volatility, substantially more than those of coal and oil.[1] Indeed, the annualized price volatility of natural gas in 2014 is 96%, far above the 17% and 8% for Brent oil and Australian coal, respectively (Mastrangelo, 2007; Geman and Ohana, 2009; Roesser, 2009; Graves and Levine, 2010; Smead, 2010; BPC, 2011; Whitman and Bradley, 2011; Alterman, 2012); see Fig. 1 below. Various consumer organizations have expressed concerns that the IPPs' fuel cost risk exposure and the natural-gas price volatility may impede investments in natural-gas-fired generation plants.[2]

Despite its real-world relevance and importance, the effect of natural-gas fuel cost risk on market price and capacity investment in a

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[1] Price volatility is commonly based on the daily percentage price changes over a pre-specified period (Roesser, 2009). The measure of volatility is taken from Eydeland and Wolyniec (2003). The analytical definition of volatility and its characteristics are detailed in the next section.

[2] See, for example, Whitman and Bradley (2011).

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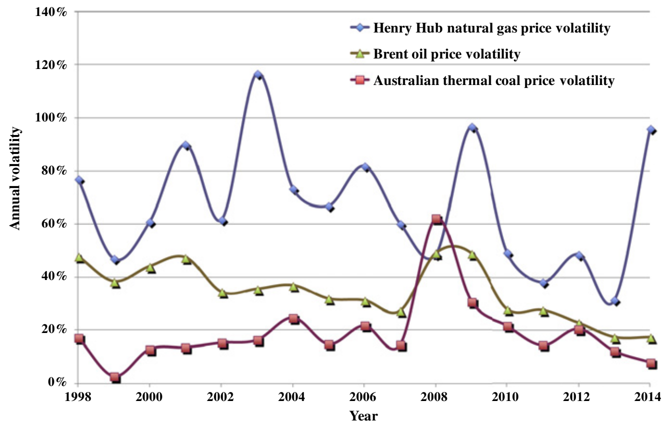

Fig. 1. Volatility of Henry Hub natural gas price, Brent oil price and Australian thermal coal price. Prices were obtained from IMF Primary Commodity Prices (2014). Computation of the annualized volatility was based on the number of trading days in a year (Eydeland and Wolyniec, 2003).

liberalized electricity market has attracted little academic attention. To be fair, the seminal work of Dixit and Pindyck (1994) presents a framework for analyzing capacity investment under uncertainty, but that framework was applied to a highly competitive market where a single firm's decision does not affect the market price.[3]

This paper extends Tishler et al. (2008) to study the effect of uncertain natural gas prices and therefore fuel costs on capacity investment and prices in a competitive electricity market. Our main research hypothesis is based on a common belief that rising fuel cost uncertainty (volatility) likely impedes generation capacity investment and reduces the expected profits of IPPs and consumer surplus. Our key findings, however, qualitatively and numerically, reject this hypothesis.

Our findings come from a two-stage model of a liberalized market of electricity generation. In the first stage, an IPP builds its optimal capacity, conditional on its perceived uncertainties of fuel cost and electricity demand. In the second stage, equilibrium prices and quantities are determined by IPPs competing in a Cournot market environment. We show that a profit-maximizing IPP increases its capacity in response to rising fuel cost volatility, so do the expected consumer surplus and expected producer profit. Expected consumer surplus further increases if the IPP hedges the fuel cost risk. The IPP's optimal strategy, however, is not to do so.

This paper makes two main contributions. First, it offers an analytical framework for assessing the effect of uncertain fuel costs on capacity investment in competitive electricity markets. The framework equally applies to other sectors and industries (e.g., petrochemical and aviation, where capacity investment is highly dependent on fuel cost volatility). Second, it demonstrates that government should not intervene to reduce the price volatility of a well-functioning natural gas spot market because such intervention can have the unintended consequence of discouraging generation investment, raising electricity prices, and reducing consumer surplus.

The paper proceeds as follows. To provide a contextual background, Section 2 discusses natural-gas price volatility. Section 3 is a literature review of electricity capacity investment under uncertainty. Section 4 develops a two-stage model that determines equilibrium capacity and electricity prices in a competitive electricity market under fuel cost uncertainty. Section 5 analyzes a three-stage model in which the fuel cost risk can be hedged via call options. Section 6 illustrates our model's empirics with a simplified electricity market based on the data of California, the eighth largest economy of the world.[4] Section 7 concludes.

2. Natural-gas price volatility

Annual price volatility of a commodity is commonly based on its daily percentage price changes over a 1-year period (Roesser, 2009).[5] Fig. 1 shows the US daily natural gas price data's high volatility since the 1978 deregulation of the US natural gas market.

Natural-gas price volatility is mainly caused by transportation constraints and storage limitations (Eydeland and Wolyniec, 2003). The transportation of natural gas is limited by pipeline capacity and/or liquefied natural gas (LNG) capacity. Natural gas storage is limited to depleted reservoirs, salt formations or LNG tanks. Production disruptions and demand spikes trigger large natural-gas price increases (Alterman, 2012), further magnified by low inventory (Geman and Ohana, 2009).

High natural gas price volatility implies that a natural-gas-fired generation plant's cash flow in a competitive electricity market is highly uncertain and this uncertainty may be further exacerbated by electricity demand uncertainty.[6] The plant's fuel cost risk hurts its owner's project financing (Stern, 1998), thus discouraging capacity investment that in turn causes electricity price spikes on days of high demand.

While an IPP may use call options to hedge against the fuel cost risk and stabilize its cash flows, the risk management strategy is not costless because its expected profit is reduced by the cost of procuring the call options. Hence, a risk-neutral IPP would not hedge *sans* the need for cash flow stability, as verified by our analysis of a three-stage model in Section 5.

3. Literature review

Prior to the 1980s, the electricity sectors in various regions of the world were vertically integrated monopolies. Generation expansion models were designed to find the minimal present value cost of meeting the projected future demand over a long planning horizon (e.g., 20 years), subject to such constraints as fuel availability, resource adequacy, and emissions limit. Demand growth is the main source of uncertainty in these models. Anderson (1972) reviews several optimization models that determine the least-cost investment in a vertically integrated market. All parameters in the optimization are assumed to be deterministic, despite the stochastic nature of future demands and costs.

Hartman (1972) studies the effect of uncertainty on the investment decisions of a competitive profit-maximizing firm, demonstrating that rising marginal cost volatility tends to increase capacity investment. Levin et al. (1985) extend the capacity investment model to a monopoly facing uncertain fuel costs, showing that for normally distributed fuel costs, the monopoly's optimal capacity investment is insensitive to fuel cost uncertainty.

Restructuring of the electricity sector in the 1990s to introduce competition in the generation segment requires a new modeling approach. Capacity expansion is no longer the result of total cost minimization, but the interactions among profit-maximizing firms. The competitive market models that accommodate these developments fall into two main classes: *equilibrium models* and *simulation models* (Ventosa et al., 2005). The most common equilibrium model uses Cournot competition, where the strategic variable is the electricity output (Andersson and Bergman, 1995; Borenstein and Bushnell, 1999; Murphy and Smeers, 2005; Tishler et al., 2008). Other models use *Bertrand* competition,

3 Applications of real option theory to oligopolistic framework, such as in Bouis et al. (2009), focus on investment timing, but not optimal capacity expansion, which is the main interest of our paper.

4 http://www.latimes.com/business/la-fi-california-world-economy-20150702-story.html.

5 Eydeland and Wolyniec (2003) define the annualized volatility, σ, as follows (page 82, eq. (3.9)): $\sigma = \sqrt{\frac{1}{n-1}\sum_{i=1}^{n}\left(\frac{\log P_i - \log P_{i-1}}{\sqrt{t_i - t_{i-1}}} - \frac{1}{n}\sum_{i=1}^{n}\frac{\log P_i - \log P_{i-1}}{\sqrt{t_i - t_{i-1}}}\right)^2}$, where $\{P_i\}$ denotes the time series of historical prices observed at times t_i, $i = 0,\ldots,n$, and $t_i - t_{i-1}$ are year fractions. A year fraction equals the length of the interval, in days, between two observations, divided by 365 or by 250 (when only trading days are accounted for).

6 Both price and sales risks can be mitigated by forward contracts that specify the must-take quantity at known prices and tolling agreements that set the capacity lease payment and transfer part or all of the natural gas cost risk from the sellers to buyers. A detailed investigation of forward contracts and tolling agreements, however, is beyond the scope of this paper.