Fuel Cost Uncertainty and Capacity Investment in Competitive Electricity Markets

Ph.D. Thesis

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Abstract

Over the past four 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 competition into electricity markets exposes the IPP to risks previously borne by end-users.

Large-scale natural gas developments during the last decade (e.g., shale gas and hydro fracking in the US) are mainly responsible for the greatly expanded use of natural gas in electricity generation. Relative to coal-fired generation plants, natural gas-fired generation plants have less emissions and shorter construction periods (MIT, 2011). They are 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). However, natural gas-fired generation faces large fuel cost risks because: (a) natural gas constitutes about 80% of variable generation costs, and (b) natural gas price volatility is large, substantially more than oil (Mastrangelo, 2007; Geman and Ohana, 2009; Regnier, 2007; Roesser, 2009; Graves and Levine, 2010; Smead, 2010; BPC, 2011; Whitman and Bradley, 2011; Alterman, 2012).

Despite its real-world relevance and importance, the effect of natural gas fuel cost risk on market price and capacity investment in a liberalized electricity market has attracted little academic attention. While the framework of Dixit and Pindyck (1994)[1] can be used to analyze capacity investment under uncertainty, it only applies to highly competitive markets where a single firm's decision does not affect the market price.

[1] See Frayer (2001), Näsäkkälä and Fleten (2010), Fuss and Szolgayová (2010), Geiger (2011), Henriques and Sadorsky (2011), Bistline (2015), Gugler et al, (2016) for various applications of capacity investment under uncertainty in the electricity sector.

Extending Tishler et al. (2008b), this dissertation assesses the effect of uncertain natural gas prices, and therefore uncertain generation costs on capacity investment and prices in competitive electricity markets. Our basic model (Chapter 5) consists of a two-stage decision process. In the first stage, an IPP builds its optimal capacity, conditional on the perceived uncertainties of fuel cost and electricity demand. Equilibrium prices and quantities are determined in the second stage, in which IPPs compete in a Cournot market environment. Counter to common beliefs (BPC, 2011; Whitman and Bradley, 2011; Alterman, 2012), we show that a profit-maximizing IPP increases its capacity in response to rising fuel cost volatility, chiefly because the asymmetric nature of natural gas price distribution implies higher probability for small values as the volatility increases. Consequently, expected consumer surplus and producer profit increase with fuel cost volatility.

Despite the positive effect of fuel cost volatility on expected profit, firms may worry about the risk of high fuel cost's impact on their ability to obtain financing for their plant construction. Therefore, we study various means of hedging fuel costs risk. First, we study in Chapter 6 the use of call options as a hedging strategy against higher fuel costs. We find that expected consumer surplus increases if the IPPs use call options to hedge the fuel cost risk. However, the IPPs optimal strategy is not to do so due to the hedging cost that lowers the expected profit. Second, we examine in Chapter 7 the possible use of a dual fuel plant to hedge against fuel price risk (e.g., the plant can switch to the alternative fuel when the natural gas price spikes). We find that consumers and producers may benefit from dual fuel capability, because it sets floors for profits and consumer surplus. However, when the dual fuel generation cost is very high, the use of dual fuel capability may lead to smaller capacity and, thus, reduce profits and consumer surplus. Finally, we investigate in Chapter 8 the use of two technologies as a hedging strategy, assuming that the fuel price of natural gas is volatile and the fuel price of coal is fixed. We find that the use of coal in the capacity mix reduces the probability of both low and high profits. I.e., unlike the call options and dual fuel capability, the two-technology mix implies not only a profit floor, but also a profit cap. Further, firms tend to increase their natural gas capacity if the natural gas price becomes more volatile, since the asymmetric shape of the natural gas price distribution implies that the probability of low natural gas prices and, therefore, profits, increase in this case. Consumer surplus is not affected by the technology mix, because total capacity and equilibrium generation remain similar to those of a single technology market.

Furthermore, we empirically demonstrate the theoretical results in Chapters 6 to 8 with stylized data similar to those of California and Texas.

In summary, this dissertation fills some of the literature gaps created by the extant studies' empirically implausible assumption that fuel prices in electricity generation are constant. It also provides insights and decision-supporting tools to firms and policy makers facing uncertain fuel prices in their strategies for capacity investment and risk management.

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1. Background, objectives and contribution

1.1 Background

The electricity sector in most[2] countries was originally a government-owned integrated monopoly that generated, transmitted and distributed electricity to consumers. Since the 1980s, many countries have reformed[3] their electricity sector to attract private investment, achieve better efficiency and lower the retail price (Newbery 1995, 2002, 2005; Joskow, 2006, 2008; Shively and Ferrare, 2010). As part of the reform, integrated electricity monopolies were restructured, and the generation segment was privatized and opened to competition. In some countries, competition was also extended to the retail segment (e.g., New York and Texas in the US, Alberta and Ontario in Canada, the UK in Europe, and Victoria and Queensland in Australia).

In a regulated market, capacity investment is centrally planned. The regulator approves capital expenditure, and the tariff is set to recover the returns on and of the approved investments under the cost of service regulation. In a deregulated market, market forces set the price of electricity and the investment in new capacity reflects the decentralized decision making of IPPs. Specifically, electricity prices are set by a bidding process, which may be at times augmented by bi-lateral agreements between producers and buyers. Investment in new capacity is determined by producers, according to their assessments of their expected future profits.

Power producers in liberalized markets bear risks that were previously borne by end-users via the regulated cost-of-service tariff. These risks include (Gatti 2008):

- Pre-completion risks: The risk of construction delays or cost overruns Post-completion risks:

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[2] A notable exception is the US, where large integrated utilities are privately owned.

[3] Other countries such as Israel and the mid-west states in the US have maintained the monopolistic structure of the electricity sector.

  - Supply risk – Fuel needed for the plant's operation may be supplied in insufficient quantities, at low quality or high prices.
  - Profit risk – The risk of unexpected low profit, due to unexpectedly low market prices or sales.
  - Operation risk – Underperformance of the plant, due to unexpected low capacity availability or high heat rates. This can occur in the plant's commissioning phase or result from the plant's deteriorating performance.
- Risks common to pre- and post-completion: Inflation risk, interest rate risk, regulatory and legal risk, and environmental risk.

This dissertation focuses on the fuel price risk, a supply risk that may be exacerbated by demand uncertainty.

A commodity's annual price volatility is a common measure[4,5] based on the daily percentage price changes over a pre-specified period (Regnier, 2007; Roesser, 2009). Figure 1-1 shows that the US daily natural gas price is highly volatile, substantially more so than coal and oil. Indeed, the annualized price volatility of natural gas in 2014 was 96%, far above the Brent oil's 17% and Australian coal's 8% (Mastrangelo, 2007; Geman and Ohana, 2009; Regnier, 2007; Roesser, 2009; Graves and Levine, 2010; Smead, 2010; BPC, 2011; Whitman and Bradley, 2011; Alterman, 2012).

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. When natural gas production is disrupted or demand spikes, natural gas prices surge (Alterman, 2012). Volatility is further magnified by low inventory (Geman and Ohana, 2009).

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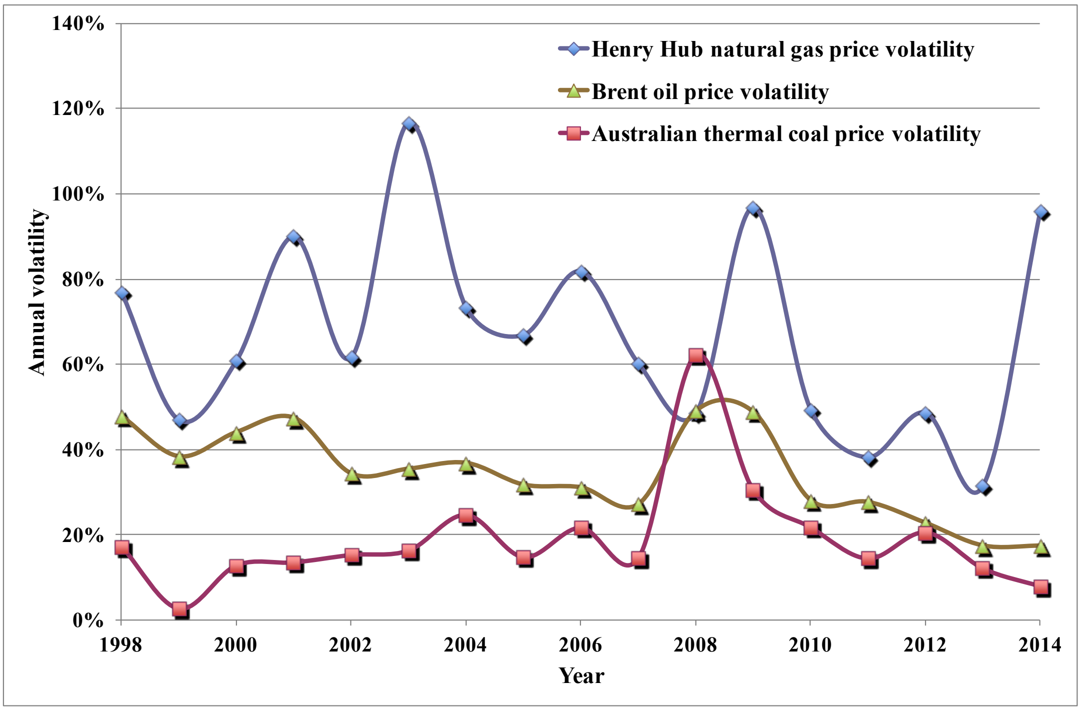
[4]The analytical definition of volatility and its characteristics are detailed in Section 3.5.

[5]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.

Figure 1-1: Volatility of Henry Hub natural gas price, Brent oil price and Australian coal price



Source: 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).

High natural gas price volatility implies that in a competitive electricity market, a natural gas-fired generation plant's cash flow is highly uncertain, and this uncertainty may be further magnified by electricity demand uncertainty[6,7]. The plant's fuel cost risk limits its owner's ability to obtain project financing and discourage capacity investment which, in turn, may cause electricity price spikes during periods of high demand.

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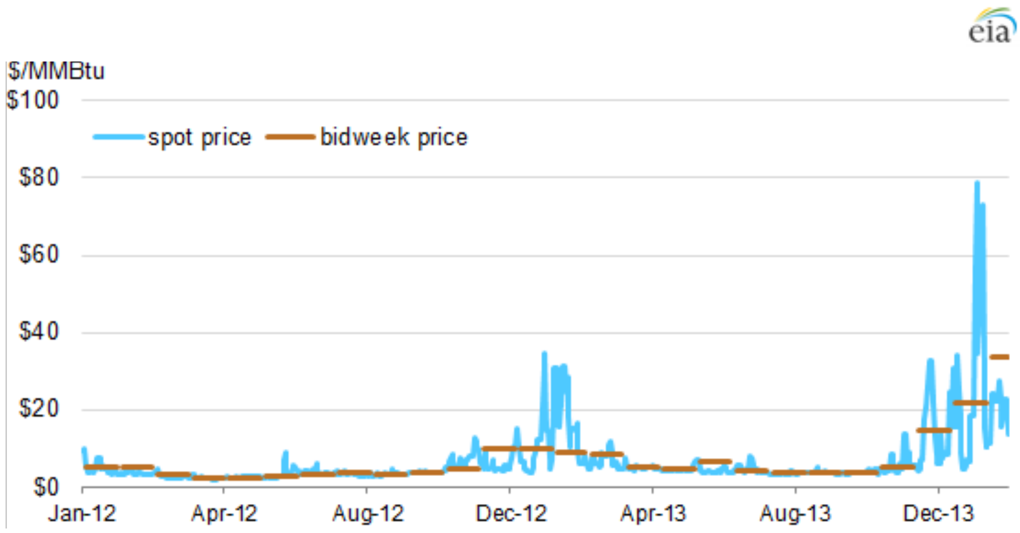
[6] Both price and sales risks can be mitigated by forward contracts that specify the must-take quantity at known prices, and tolling agreements that set the capacity lease payment and transfer part or all of the natural gas cost risk from the sellers to the buyers. A detailed investigation of forward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

[7] See Czamanski et al. (2007) for further analysis about the linkage between natural gas prices and electricity prices.

Figure 1-2 depicts the spot prices of Algonquin City-gate gas prices over a two-year period. These prices tend to spike and become volatile during the winter period, a reflection of an inelastic demand coupled with supply disruptions.

Figure 1-2: Natural gas price[8] fluctuations in Algonquin City-gate (2012 –2014)



Source: Energy Information Agency, Today in Energy, February 21, 2014

In countries where both electricity and natural gas markets are liberalized, independent power producers (IPPs) are exposed to fuel price risk, in addition to other risks (Mastrangelo 2007; Roesser 2009; Graves and Levine 2010; Smead 2010; BPC 2011; Whitman and Bradley 2011). High fuel cost volatility implies that the plant's cash flow is highly uncertain. As the cost of natural gas increases, power producers face smaller profits and higher default probabilities. Thus, investors in natural-gas-fueled electricity plants consider the uncertain future cost of fuel when determining optimal capacity investment. In reality, an IPP's uncertainty is even larger, as the demand for electricity is stochastic.

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[8] Bidweek prices reflect the transactions entered on the last five days of a month, during which traders purchase gas to be delivered during the following month (retrieved from www.api.org).

Risk exposure of power producers limits the availability of finance and, therefore, may lead to underinvestment in new capacity. Underinvestment likely causes price spikes during periods of high demand due to capacity shortage (Tishler et al., 2008b).

1.2 Research objectives

This dissertation's focus is the effect of uncertain natural gas prices on capacity investment and prices in a competitive electricity market. It also studies various means of hedging the fuel cost risk.

1. The main research objectives are as follows: To study the effect of natural gas price volatility on capacity investment and operations in a competitive electricity market.
2. To determine the combined effect of uncertain demand and uncertain fuel cost on capacity investment and electricity prices
3. To optimize the use of call options for the price of gas as a hedging strategy
4. To study the use of dual fuel plants as a means of hedging the risk of high natural gas price or supply interruptions
5. To determine the optimal capacity of an IPP operating in a competitive electricity market with two technologies, where the price of natural gas is uncertain, and the price of coal is non-stochastic.

1.3 Contribution

Deregulation accentuates the importance of studying investment under uncertainty in the electricity sector, as the capacity investment of IPPs is affected by their fuel cost risk exposure. This dissertation contributes to the capacity investment literature by studying the effect of stochastic fuel cost on optimal capacity investment and electricity prices in oligopolistic competition.

The extant literature on capacity expansion and electricity market equilibrium in deregulated markets under uncertain fuel costs is inadequate. In particular:

1. Studies often ignore uncertainty altogether (Fehr and Harbor, 1997; Murphy and Smeers, 2005; Spulber, 1981).
2. Some studies assess demand uncertainty, but assume fixed fuel costs (Gabszewicz and Poddar, 1997; Tishler et al., 2008b).
3. Tseng and Barz (2002) use simulations to study the effect of stochastic fuel cost, as well as other factors. However, simulations provide only limited insights into the relations between market conditions and the optimal decisions made by producers and consumers.
4. Hartman (1972) studies the effect of cost volatility on investment. However, he assumes perfect competition, which does not apply to current electricity markets.
5. Real options theory (Pindyck, 1991; Frayer, 2001; Näsäkkälä and Fleten, 2010; Fuss and Szolgayová, 2010; Geiger, 2011; Henriques and Sadorsky, 2011; Bistline, 2015; Gugler et. al, 2016) offers a framework for valuation of investment under uncertainty in the power sector. However, it assumes that power producers are price takers and electricity price does not depend on market characteristics, such as the number of firms in the oligopoly or the demand function.
6. Portfolio theory (Awerbuch and Yang, 2007; Zhu and Fan 2010; Arnesano, 2012) incorporates various types of risk. However, portfolio theory ignores market competition and the interactions among firms.

This dissertation fills some of the existing theoretical gaps by studying the effects of uncertain fuel cost on capacity decisions in a deregulated market. It is timely, relevant and important because of the electricity and natural gas market restructure already taken place in many parts of the world (Holz et al., 2015), thus causing IPPs in many countries to be exposed to fuel cost risk. This is especially true for Israel, which is now contemplating reforming its electricity sector and opening its natural gas sector to competition (Yogev, 2014; PUA, 2015; Grossman, 2016).

The dissertation's specific contributions are as follows:

1. It contributes to the study of cost uncertainty in oligopolistic competition with a (possibly) binding capacity constraint.

2. It combines fuel cost and demand risks. Some emphasis was given in the academic literature to the implications of demand risk (e.g., Gabszewicz and Poddar, 1997; Tishler et al., 2008b; Milstein et al., 2012). However, to the best of my knowledge, there is no existing study on investment decisions under the real-world phenomenon of fuel cost and demand uncertainties.
3. It enables a study of hedging strategies. In particular, one of the models analyzes the decisions on the optimal use of fuel price call options in a competitive electricity market.
4. It studies the use of dual fuel plants as a hedging strategy to prevent high fuel costs.
5. It provides a solution for the optimal generation technology mix under fuel cost uncertainty.

2. Electricity markets in the USA, the UK and Israel

This chapter is a description and assessment of electricity market restructuring (Newbery, 2005; von der Fehr et al., 2005; Murphy and Smeers, 2005; Joskow, 2006, 2008; Tishler et al., 2008b). It details the structure and key features of the electricity markets of the USA, the UK and Israel.

2.1 Electricity market reform

It is common to describe a country's electricity sector by functional segment as follows:

1. Generation
2. Transmission
3. Distribution
4. Retail
5. System Operation

In most countries, the electricity sector was originally established as a vertically integrated monopoly, which owned and managed the five segments listed above. In the 1990s, the UK and the USA restructured their electricity sectors, encouraging competition in the generation and retail segments with the goal of ensuring sufficient investment in new capacity and lowering retail prices. Other countries soon followed (Woo et al., 2004; Newbery, 1995, 1998, 2002, 2005; Joskow, 2008). There are several models for restructuring the electricity sector. The main models are (Shively and Ferrare 2010; Sioshansi, 2006; 2011):

- **Single buyer with competitive generation** – Several firms generate electricity and compete in the wholesale market. A single buyer holds a monopoly over the transmission, distribution and retail. The buyer procures electricity in the wholesale market for resale to its retail customers. The system can be operated by either the single buyer or an independent system operator (ISO).
- **Wholesale/industrial competition** – Large industrial and commercial consumers procure power directly from wholesale generators through long-term agreements.

A single buyer owns the transmission lines and continues to procure power for smaller consumers. In this model, the system operator has to be independent to ensure fair transmission access by all generators.

- **Complete retail competition** – Retail marketers procure electricity from wholesale generators for resale to end-users. A utility (or several utilities) owns the transmission and/or the distribution infrastructure and provides open and comparable services of transmission and distribution to all generators and retail marketers.

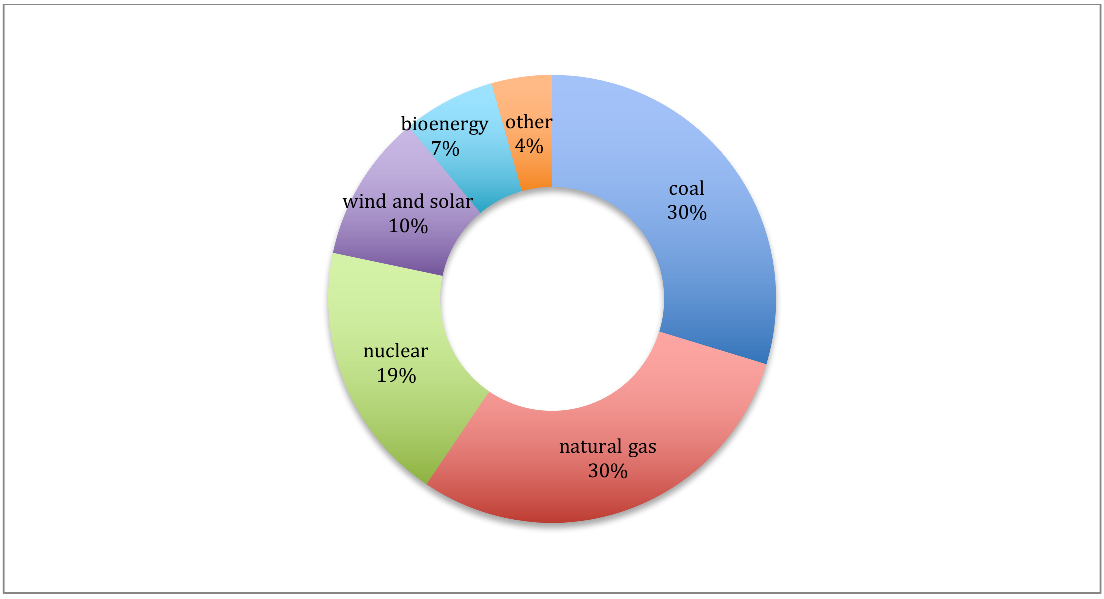
Market restructuring drastically changes the regulator's role. In a regulated market, the regulator approves capacity expansion plans, sets standards for quality of service and for reliability levels, and establishes fair tariffs that will ensure sufficient returns for the utility at a reasonable cost to customers. In deregulated markets, the regulator sets the rules of competition and the required quality of service, while prices are determined by the market. In addition, capacity plans are market-driven, with competitive generators making technology and capacity choices to maximize their future profits (Shively and Ferrare, 2010; Sioshansi, 2006; 2011; Joskow, 2008; Chao et al., 2011).

2.2 The UK electricity market

2.2.1. The UK's installed capacity, generation mix and electricity production

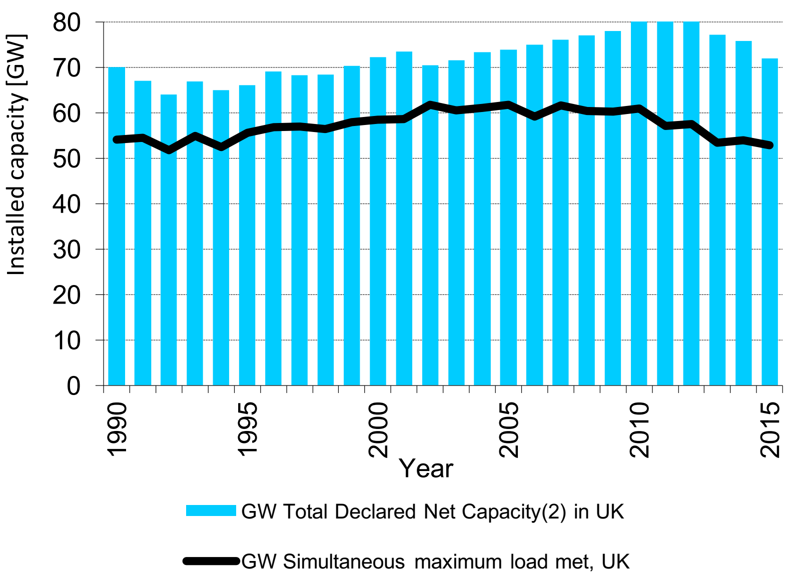
In 2013, the UK's installed capacity and electricity use were 77 GW and 339 TWh, respectively. The generation fuel mix in 2013 comprised natural gas (30%), coal (30%), nuclear (19%) and renewables (17%) (DECC, 2015).

Figure 2-1: The UK's electricity generation mix (2014)



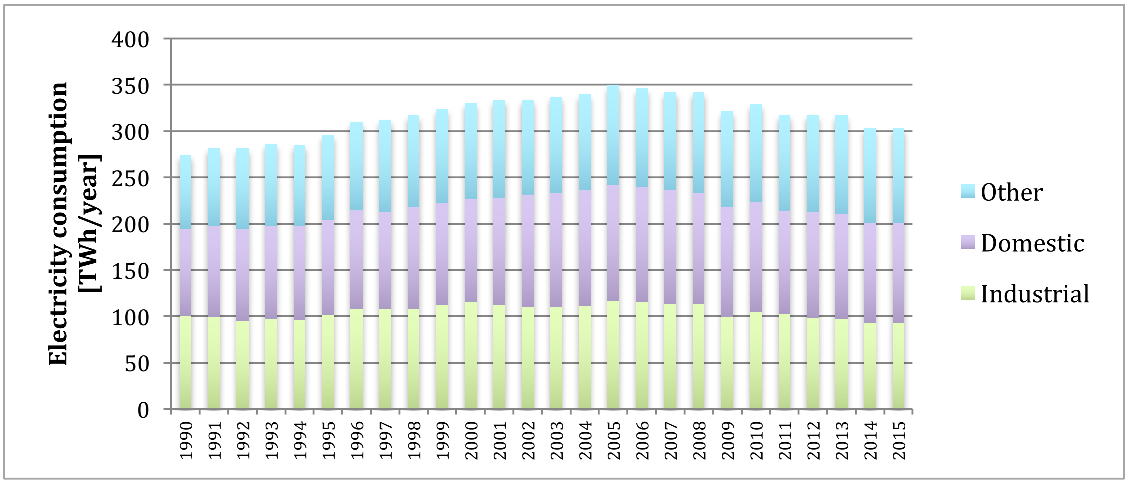
Source: (DECC 2015)

Figure 2-2: The UK's net generation capacity and maximum load



Source: Retrieved from www.gov.uk historical electricity data

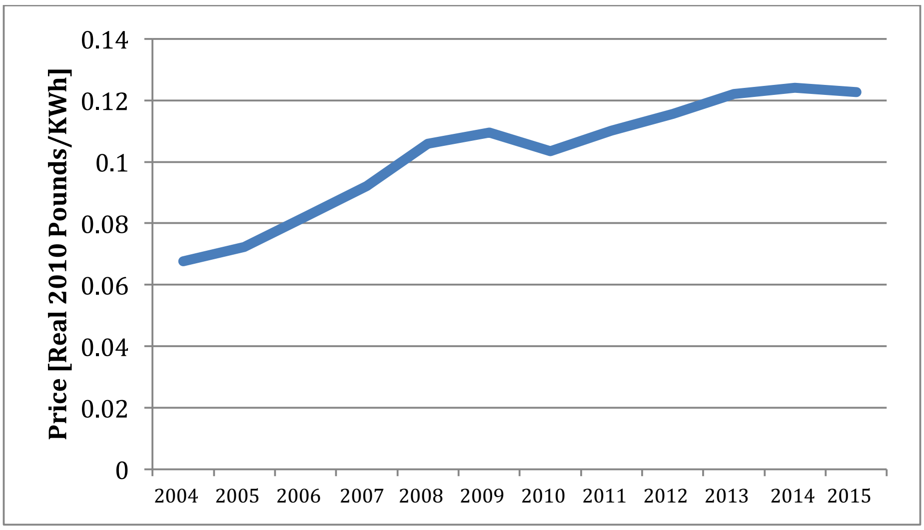
Figure 2-3: UK electricity consumption by sector (1990-2015)



Source: Retrieved from www.gov.uk historical electricity data

Figure 2-2 shows that the net installed capacity is steady over 1990-2015, though with a slight downward trend after 2010. It mirrors the overall electricity consumption in the same period shown in Figure 2-3.

Figure 2-4: The UK's domestic electricity prices (2004-2015)



Source: Retrieved from www.gov.uk historical electricity data

Figure 2-4 shows a continuous increase of electricity prices in the UK during 2004-2015, the result of slowly increasing fuel prices.

In 2012, the British government initiated a new Energy Bill and Energy Market Reform (EMR) to achieve reliable supply, carbon emissions reduction and affordable prices (DECC, 2012). These goals, however, are challenged by the expected plant retirement and demand growth. The EMR’s remedy has the following elements (DECC, 2012):

- A legally binding EU target of 15% renewable energy by 2020, with the aim of achieving a higher target of 30% by that year.
- Retirement of old coal plants via natural-gas-fired generation, renewable energy and nuclear power.
- Reconsideration of capacity markets which were abolished in 2001.
- Encouragement of efficient use of demand response.

The future of nuclear power is one of the EMR’s main challenges. The UK is expecting a retirement of about 50% of its capacity by 2035, mainly comprising old nuclear and coal plants. Nuclear power will play a significant role in the future, thanks to its low levelized cost, zero carbon emissions, and contribution to energy independence. Implementation of the nuclear policy, however, faces issues of safety, waste control, and residents' opposition to the new plants’ construction (Birmingham, 2012).

Keay (2016) challenges the UK’s EMR policy, claiming that the market is stuck in a half-planned, half-market orientation, and the government should intervene to ensure the desired balance between energy-security, environmental protection and economic efficiency. To achieve the EMR's goals, Newbery (2016) stresses the need for a new auction design for renewable energy and economic support for R&D in the electricity sector.

2.2.2. The UK’s electricity market structure

Up until 1989, the UK’s electricity sector was organized as a vertically integrated monopoly under government ownership. The Electricity Act of 1989 established a regulatory agency to set price caps, reliably meet demands, encourage competition and protect consumers (Newbery, 2005; Ehlers, 2009). The monopoly was unbundled into two generation companies, a transmission company, and 12 regional distribution companies. The companies were gradually sold to the public over several years (Ehlers, 2009). Competition was encouraged by requiring the generators to sell their output in the wholesale electricity pool. The electricity pool functioned as a day-ahead spot market: generators made supply bids and they were dispatched to the grid according to the merit-order of their bid prices. The last dispatched generator's bid price set the market price. Generators could hedge against the market price volatility.

In the first three years following the Electricity Act of 1989, generators purchased expensive British coal under long-term contracts, and could sell the power to customers under long-term contracts, thus transferring the stranded cost to customers. Only two fossil fuel companies were competing in the wholesale market, thus increasing the risk of market power abuse. To overcome this problem, companies were encouraged to sign Power Purchase Agreements (PPA), so that only a small portion of their production would be sold in the electricity pool. Hence, if a company bid a high price, it faced the risk of not being dispatched. The entry of new generators to the wholesale market was encouraged by allowing distribution companies to sign long-term PPAs with new entrants. Within a couple of years, the UK's CCGT capacity increased by 5 GW. Consequently, the size of the coal industry was halved (Newbery 2005; Keay, 2013).

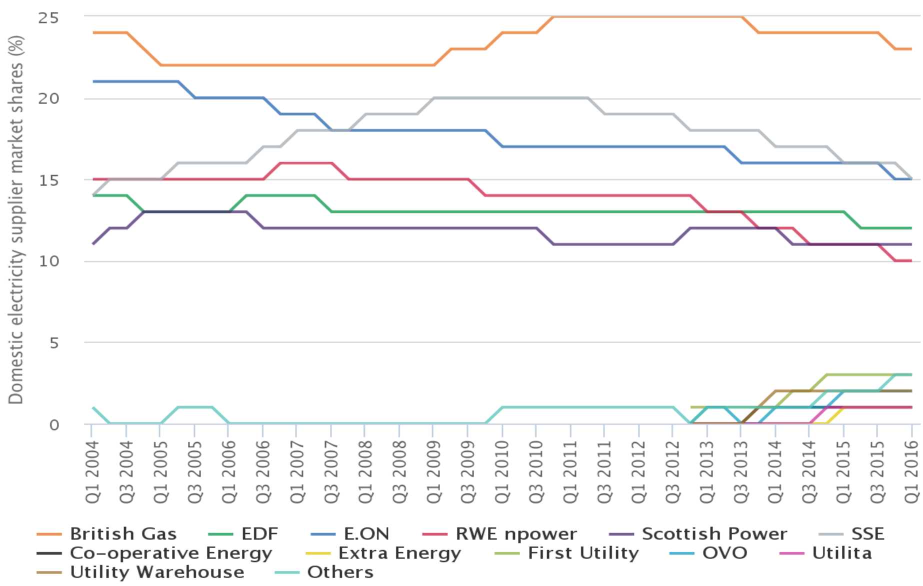
In 2001, the market design of the UK's electricity sector was revised by the NETA (New Electricity Trading Arrangements) system with the following changes:

- Capacity payments were abolished.
- Four markets were created: long-term and mid-term bilateral agreement markets, a forward market, and a day-ahead market.
- It introduced a "pay as bid" settlement system and prices were no longer determined by the single market-clearing price rule.

- Generators could offset the price risk by purchasing regional distribution companies (vertical integration). However, they were required to divest some of their capacity first, thus reducing the market concentration.

In 2005, the system was extended to include Scotland, and the market name was changed to "British Electricity Trading and Transmission Arrangements" (BETTA) (Ehlers, 2009; Keay, 2013).

Figure 2-5: Market shares of electricity generation by company in the UK's electricity market



Source: Retrieved from OFGEM.gov.uk

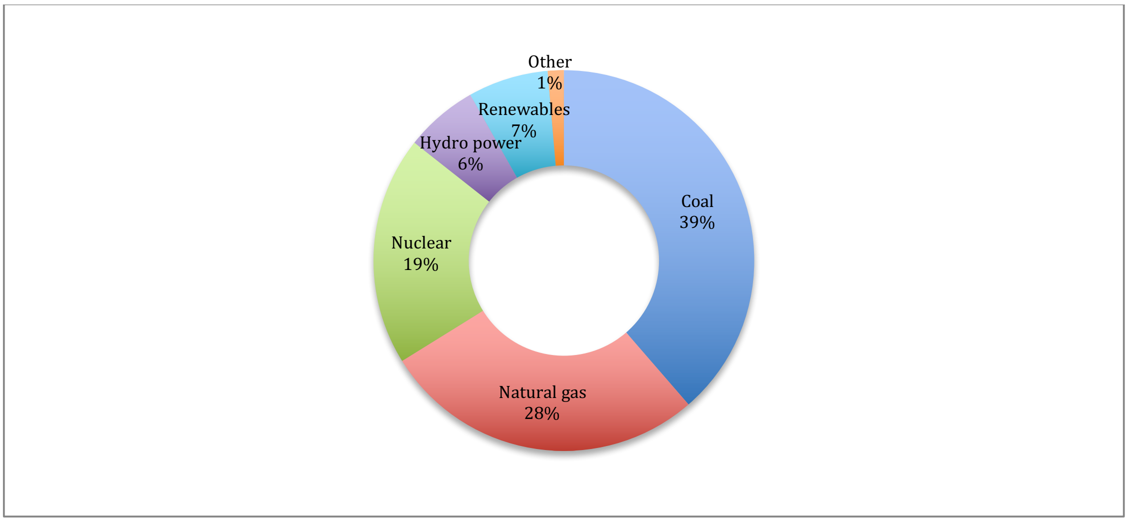
Figure 2-5 depicts the market shares of electricity companies in the UK during 2004-2015. While six companies generate most of the electricity in the UK, none holds a market share larger than 25%, in accordance with Newberry's (2005) 'best practice'.

2.3 The US electricity market

In 2014, the total US generation capacity and electricity use were 1100 GW and 4100 TWh, respectively. The US generation mix in 2014 was dominated by coal (39%) and natural gas (28%) (Figure 2-6; EIA 2016).

2.3.1. Installed capacity, generation mix and electricity production

Figure 2-6: US electricity generation mix (2014)

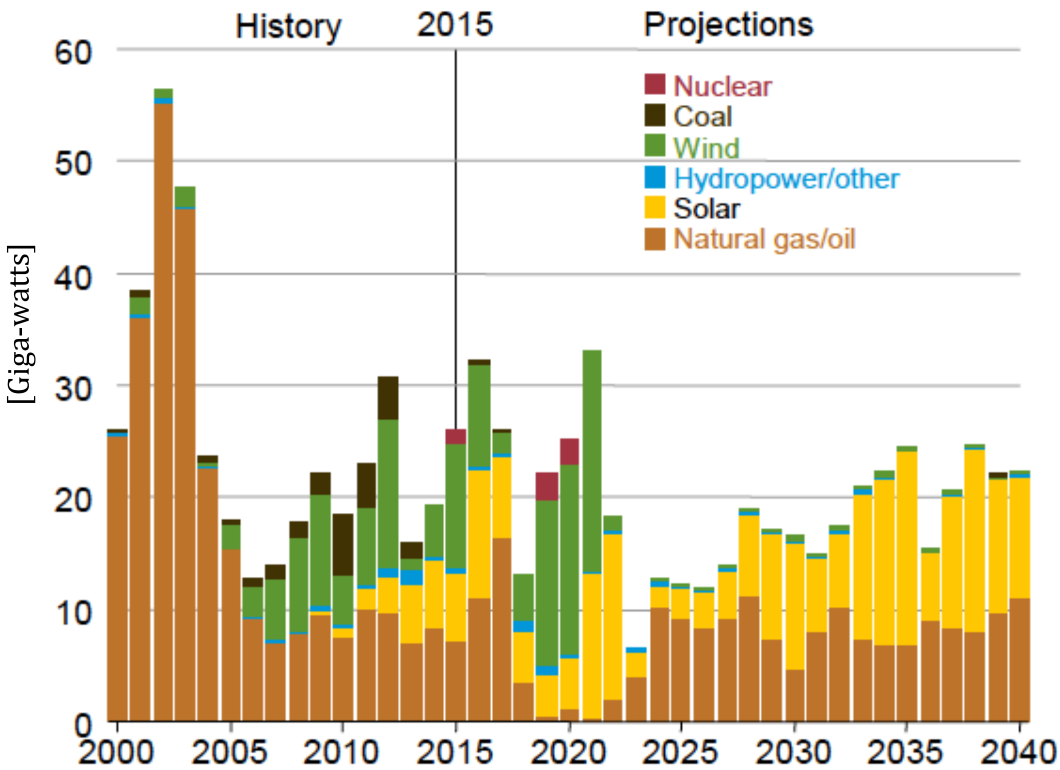


Source: EIA, 2016

US electricity generation by coal-fired capacity declined from over 1750 TWh in 2010 to less than 1400 TWh in 2015. Over the same period, electricity generation by natural gas-fired capacity increased from 1100 TWh to 1400 TWh (EIA, 2016).

The coal capacity share is expected to drop to 35% by 2040 (MIT, 2011). The new capacity in the USA is expected to consist of 63% natural gas and 31% renewables (Figure 2-7; EIA, 2013).

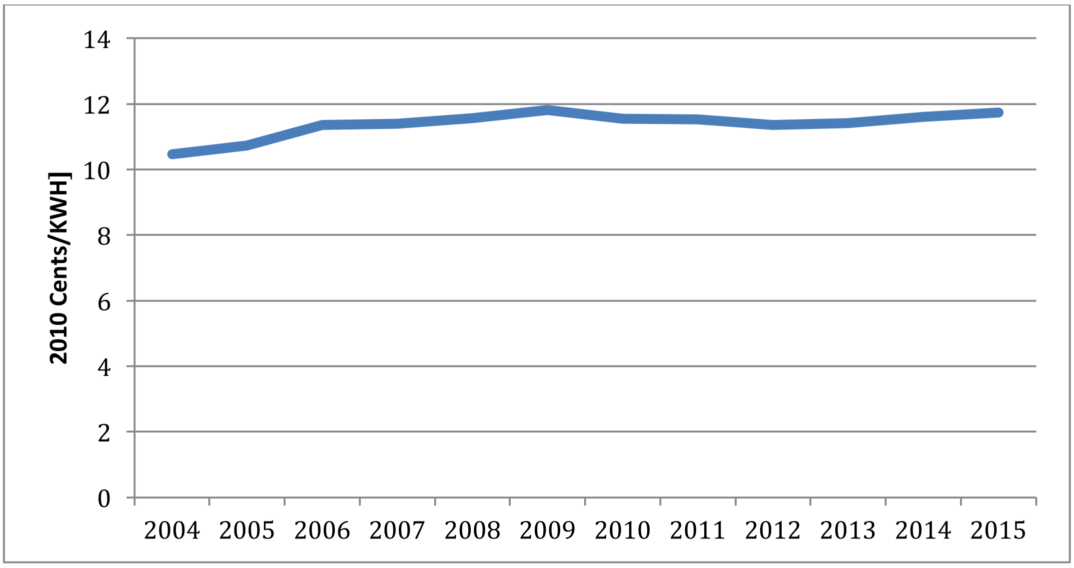
Figure 2-7: Historic and projected capacity addition by fuel (2000-2040)



Source: Retrieved from www.EIA.gov, Annual Energy Outlook, 2016 (with Projections to 2040)

The USA does not have a renewable portfolio standard (RPS) at the federal level. However, 30 states and the District of Columbia have RPS at the state level. Most states are currently either meeting or exceeding the RPS goals. This success is attributed to the decline of the cost of renewable technologies and to tax credits provided by the federal government (EIA, 2013). Generation from renewable resources, other than hydropower, increased from 30 billion KWh in 1989, to over 160 billion KWh in 2011. Most of this growth (75%) is attributed to wind energy (EIA, 2013).

Figure 2-8: US retail electricity price



Source: (EIA statistics)

Figure 2-8 depicts the historic retail prices in the USA. The average prices remained stable, unlike those in the UK during a similar period shown in Figure 2-4.

2.3.2. US electricity market structure

Starting in the 1980s, US electricity markets were gradually opened to competition. Prior to that, local power utilities in the USA were structured as vertically integrated monopolies. Some of the utilities were privately owned and others were cooperatives or owned by municipalities. In 1978, following the oil crisis, the Public Utility Regulatory Policy Act (PURPA) encouraged the development of independent power producers (IPPs). Utilities were required to purchase power from qualified IPPs at avoided costs. Each state's interpretation of the PURPA led to different IPP development levels across the USA (Shively and Ferrare, 2010; Joskow, 2006).

The Energy Policy Act of 1992 attempted to further increase competition. The Act set the legal framework for the sale of power directly from IPPs to large customers or retail marketers. In 1996, the Federal Energy Regulatory Commission (FERC) issued Order 888, mandating open and comparable transmission access for all grid users at just and reasonable wheeling rates. The act required a functional separation of generation, transmission and distribution activities, ensured access to the grid, established tariffs for services offered by utilities to wholesale generators, and encouraged the establishment of Independent System Operators (ISOs). As a result, ISOs were formed in California, New England, New York and PJM[9] (Shively and Ferrare, 2010). While Texas is not under the federal jurisdiction, it also established its own ISO.

The FERC Order 2000 of 1999 intended to foster competition by integrating fragmented transmission areas into larger grids. ISOs were transformed into Regional Transmission Operators (RTOs) to manage transmission and market activities in larger geographic areas, often crossing the borders of states, and to enable open access by all market participants.

The second aspect of market restructuring was the transition from utility ownership to independent power producers. This transition also involved a shift from cost recovery regulation to a market-based pricing model. As a result, some utilities book value was higher than their market value. These utilities were allowed to maintain higher retail tariffs to recover their investments (Borenstein and Bushnell, 2015). Despite power contracts for stranded assets, Joskow (2006) argues that wholesale competition continued to develop in the USA. The transition from utility ownership to independent power producers was voluntary and some regions resisted the change out of fear of losing state control (Shively and Ferrare, 2010). Several events in the early 2000s impeded the implementation of competition in the US electricity sector: (a) the California crisis of 2000-2001 (Blumstein et. al, 2002; Joskow, 2006); (b) the Enron fraud and bankruptcy (Kroger, 2005); and (c) the rising prices of coal and natural gas that made retail competition less attractive (Apt, 2005; Joskow, 2006; Borenstein and Bushnell, 2015).

In 2002, the FERC proposed a standard market design, but the proposal was later withdrawn. The proposal included an independent transmission operator, day-ahead and

[9] PJM – Pennsylvania, New Jersey and Maryland

real-time wholesale markets, a commitment to provide sufficient capacity and a cap for energy and ancillary services[10]. Helman et al. (2008) describe the wholesale market design that evolved in the USA, with an emphasis on day-ahead and real-time wholesale markets.

Hyman (2010) compares prices in regulated and de-regulated markets in the USA over several decades, concluding that deregulation[11] had not led to the expected price reduction. Borenstein and Bushnell (2015) argue that competition in the US electricity markets had increased market efficiency, but prices were mainly affected by exogenous factors such as fuel costs, rather than market restructuring.

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[10] The FERC's definition of *ancillary services* is as follows: "Those services necessary to support the transmission of electric power from seller to purchaser, given the obligations of control areas and transmitting utilities within those control areas, to maintain reliable operations of the interconnected transmission system. Ancillary services supplied with generation include load following, reactive power-voltage regulation, system protective services, loss compensation service, system control, load dispatch services, and energy imbalance services" (see glossary and FERC order 888 at www.FERC.gov).

[11] A detailed comparison of the effects of deregulation on electricity production efficiency and prices is available, among many others, in Apt (2005), Borenstein et al. (2002), Costelo (2003), Fabrizio et al. (2007), Woo et al. (2006) and Woo and Zarnikau (2009).

2.4 Israel's electricity market

2.4.1. Israel's capacity, generation mix and electricity production

Israel is an electricity island, and the entire country's demand is met by local generation. In 2014, the installed capacity and electricity use in Israel were 14.6 GW and 62 TWh, respectively (PUA, 2015).

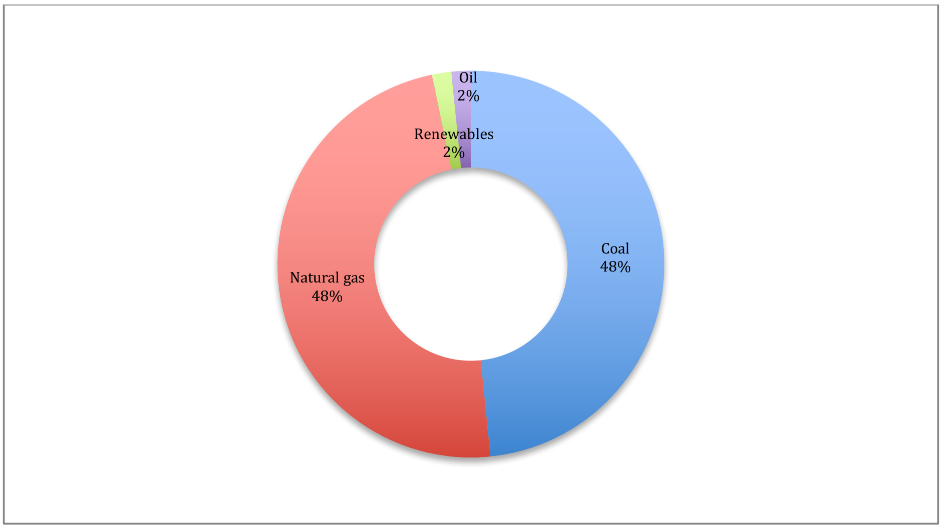
Up until the late 1990s, Israel had no access to natural gas resources and its generation mix was limited to coal and oil. The discovery of the Yam-Thetis natural gas reservoir in 1999 and a later pact with Egypt enabled the use of natural gas for electricity generation for the first time. The pact, however, was scrapped in 2012, following repeated sabotage acts on the natural gas pipeline from Egypt to Israel. Recent discoveries of natural gas reserves in Israel's exclusive economic zone (EEZ) have enhanced the availability and reliability of the natural gas supply to Israel, encouraging a shift of the electricity generation mix towards natural gas (Shaffer, 2011; PUA, 2015).

In 2011, the government set a RPS target of 10% in Israel's electricity capacity by 2020.[12] In 2015, the target was extended to 17% by 2030. However, the market penetration of renewable technologies has been slow: as of 2014, the share of renewables in the total generation mix was only 1% (PUA, 2015). This share increased to 2% in 2016 (PUA, 2017).

Future plans for the Israeli electricity sector aim to achieve (a) a planning reserve margin equal to 20% of Israel's projected annual system peak; (b) retirement of 1.4 GW coal capacity; (c) an increase in natural gas capacity, including combustion turbine (CT), combined cycle gas turbine (CCGT) and combined heat and power (CHP); (d) the RPS targets; and (e) 800 MW of pumped storage (PUA, 2015).

[12] Israel's Prime Minister Office (2011) 'Decision no. 3484'

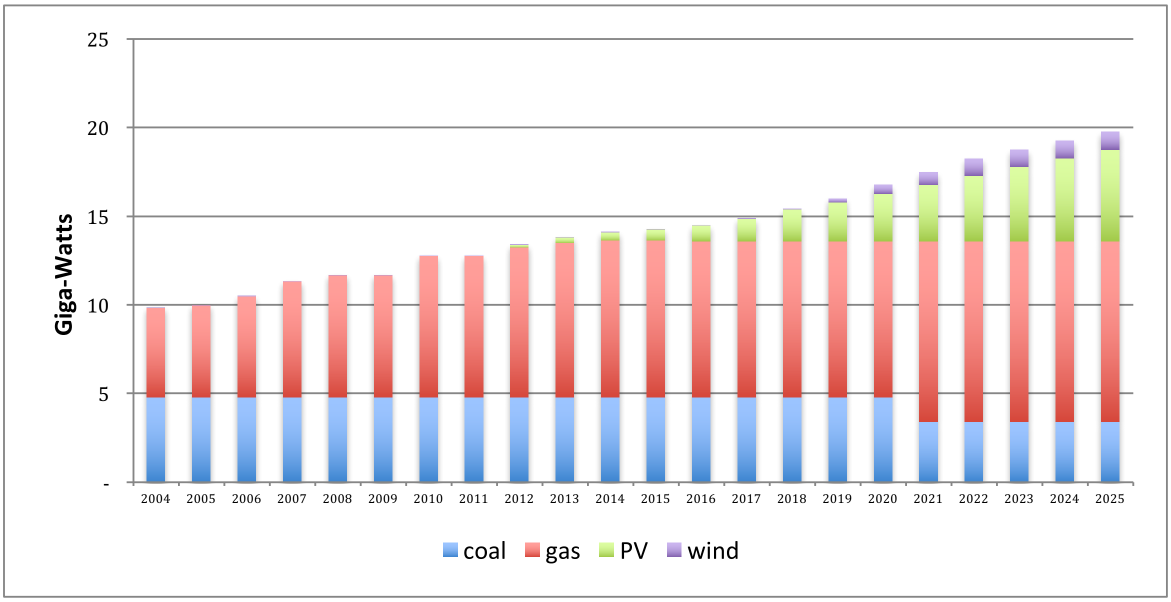
Figure 2-9: Israel's electricity generation mix (2014)



Source: Retrieved from Israel's Electricity Regulator website: www.PUA.gov.il

Figure 2-10 depicts the historic and projected capacities according to fuel type. Natural gas and renewable capacities are expected to increase over the next decade, while coal capacity is expected to gradually retire.

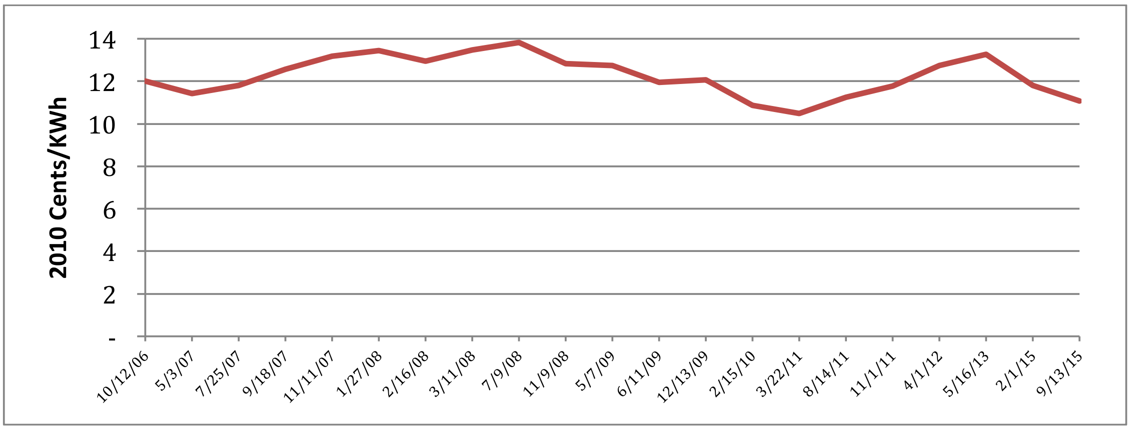
Figure 2-10: Israel's projected installed capacity by generation fuel (2004-2025)



Source: Adapted from (PUA, 2015)

Retail prices in Israel increased in 2011-2013, due to disruptions in the natural gas supply that led to an increased use of diesel generation. Prices have declined since 2013, following the development of the Tamar Natural Gas Reservoir and the rapid decline in the world's coal prices (PUA, 2015).

Figure 2-11: Evolution of retail prices in the Israeli electricity sector



Source: Adapted from (PUA, 2015)

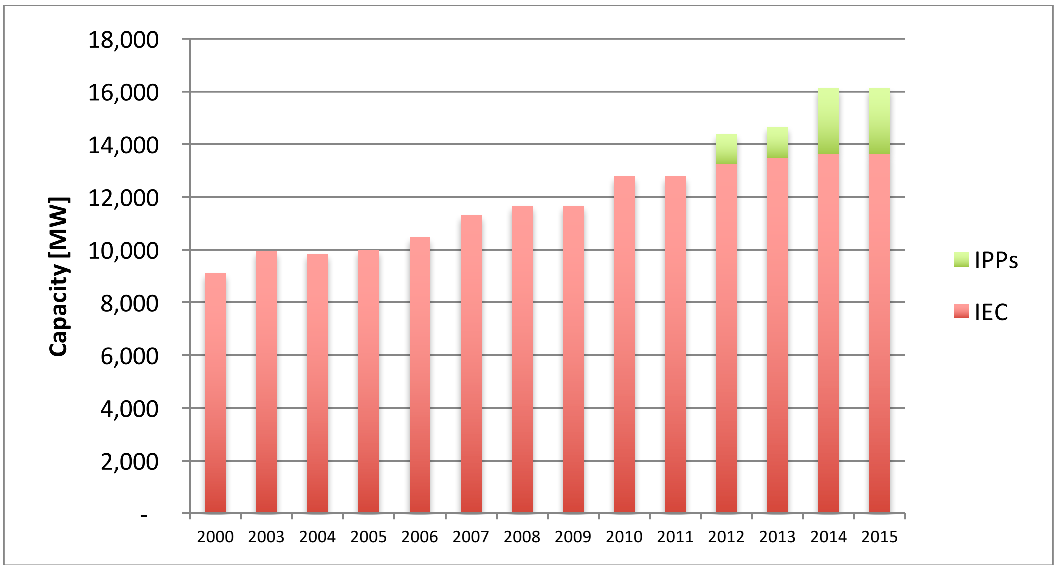
2.4.2. Israel's electricity market structure

The Israeli electricity sector is dominated by a government-owned, vertically integrated monopoly, the Israeli Electric Corporation (IEC). An electricity regulation agency (PUA - Public Utility Authority) was established by the Electricity Market Law in 1996. Over the last two decades, several attempts were made to reform the electricity sector (Czamanski, 1994), but eventually, the structure was unchanged, mainly due to the resistance of the IEC's labor union and the government's ineffective policies in establishing the complex electricity market (MQGI, 2009). In 2003, the Israeli government decided to unbundle the IEC and allow competition in the electricity sector. Wholesale generation and customer service were to be privatized, while transmission and distribution would remain regulated and provide open access to all users (Ben Shahar, 2003). The government confirmed the plan in 2006 and decided to deregulate wholesale electricity prices and provide compensation for the IEC labor union. Attempts to implement a limited reform resumed in 2013, following the IEC's financial crisis (Yogev, 2014). The reform plans, however, were not implemented.

Tishler et al. (2002, 2006, 2008a) and Tishler and Woo (2006) explained why the reform plans did not fit the unique characteristics of the Israeli market. Tishler et al. (2002) assessed the potential of a competitive electricity market in Israel and asserted that the number of firms that would be willing to buy IEC assets and generate electricity was small, due to a too small ROE, enforced price caps, the lack of local fuels and a hostile environment. As a result, they believed firms were likely to abuse market power, and that the average price was likely to exceed the average regulated price. Tishler et al. (2002) and Tishler and Woo (2006) instead proposed using performance-based regulation (PBR). Tishler and Woo (2006) discussed the feasibility of a deregulated market in Israel, finding that there might not be a feasible number of electricity producers in Israel to achieve a competitive market. This is because the number of producers must be small enough to recover their investment costs. At the same time, the number must be large enough to avoid market power abuse; otherwise, the price of electricity in a deregulated market would likely be higher than the price in a regulated market. Tishler et al. (2006) provide a cost benefit analysis of the reform, showing that a flawless implementation of the reform might increase the profit of the producers and the income of the government from taxes, at the expense of the consumers. A less than perfect implementation would lead to a negative net benefit. Tishler et al. (2008a) assess the prospective equilibrium price in a competitive wholesale market in Israel. The authors conclude that prices are expected to be higher than the current regulated monopoly price; yet, the generation units may not be financially viable. Czamanski (1994), Sverdlov et al. (2004) and Grossman (2016) emphasize the need for reform and set the necessary conditions for success. The authors stress the need for unbundling the IEC and limiting market power in the generation and retail segments.

Generation capacity investment by the IPPs has been steadily increasing in Israel over the last 15 years, thanks to the government policy to actively support IPPs' capacity development and inhibit the IEC's capacity expansion. Consequently, IPP capacity and electricity production shares were respectively 18% and 27% in 2015, expected to reach 30% and 40% in 2020 (Yogev, 2014; PUA, 2015). The Treasury and Energy Ministries are currently exploring several competitive or semi-competitive electricity market structures, one of which could be selected for implementation in the near future. A description of a competitive Israeli electricity market, using stylized data, was described and assessed by Tishler et al. (2006, 2008a) and by the PUA (2015).

Figure 2-12: The IEC and IPPs installed capacity (2000-2015)



Source: Retrieved from www.PUA.gov.il

Installed generation capacity in Israel is growing at a rate of 3-5% per year to reliably meet the growing demand. In 2009, the Israeli government decided that all additional capacity would be owned by private producers (PUA, 2015). Figure 2-12 depicts the growing share of IPPs in the Israeli market. The private market is dominated by three large IPPs and many other small producers (PUA, 2015).

3. Natural gas markets in the UK, the USA and Israel

Over the past few decades, natural gas has evolved from a byproduct of oil drilling to become a key component in the global energy mix. This chapter outlines the physical attributes of natural gas, the global natural gas markets and the unique characteristics of natural gas as a commodity. Finally, the evolution of the natural gas markets in the USA, the UK and Israel are described and examined.

3.1 Natural gas categories and types

Natural gas is a mixture of hydrocarbons in a gaseous form, 70%-90% of which is methane. It contains other hydrocarbon gases such as ethane, propane, butane and pentane, as well as carbon dioxide, nitrogen and hydrogen sulfide. There are various types of natural gas, depending on its components (MIT, 2011; IEA, 2012):

- Natural gas is *dry* if it includes mainly methane; otherwise, it is *wet*.
- The gas is *sour* if the levels of hydrogen sulfide are significant.
- Natural gas is *associated* if it is extracted in conjunction with oil production. *Non-associated* gas is developed as a primary product.

Global natural gas reserves are divided into two main categories (MIT, 2011; IEA 2012):

- *Conventional gas* refers to reserves that can be recovered by conventional technology.
- *Non-conventional gas* refers to reserves that are trapped in tight or low permeability rock. The recovery of non-conventional gas employs hydro fracking, which requires a larger amount of water and has a higher potential for polluting water resources, often resulting in higher emissions of greenhouse gases and other pollutants.

Subcategories of non-conventional gas are (IEA, 2012; IEA, 2015):

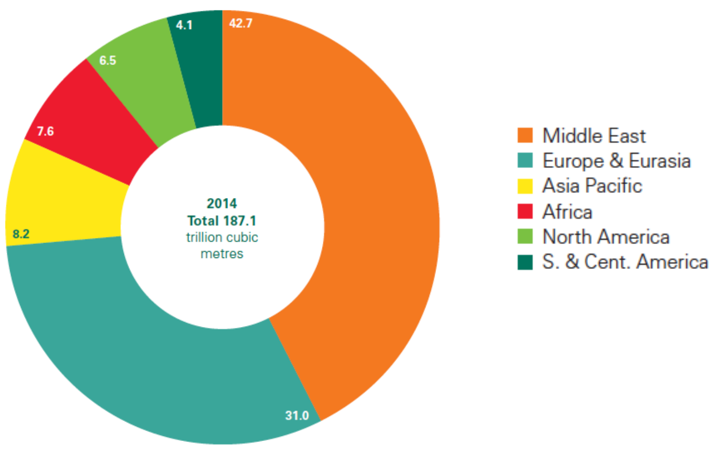
- *Shale gas* is gas that is trapped in shale formation rock. The shale rock is also the source rock of the gas.

- *Coal bed methane* is trapped in coal beds. In the past, this gas was recovered to reduce the risk of explosions in coal mines. Currently, coal bed methane is also recovered from non-minable coal seams.
- *Tight gas* is trapped in low permeability rock.

3.2 Global natural gas supply and demand

The IEA (2015) estimates that the global natural gas reserves are about 781 TCM, of which 437 TCM (56%) are conventional gas resources. Proven natural gas reserves in 2014 were estimated to be about 261 trillion cubic meters (TCM) by IEA (2015) and about 187 TCM by BP (2015). Figure 3-1 depicts the remaining global gas reserves in 2014 by region. Russia and the Middle East hold the majority of the world's natural gas reserves.

Figure 3-1: Global gas reserves by region (2014)



Source: adapted from BP (2015)

Global consumption of natural gas has increased from 2,435 million tons of oil equivalent (MTOE) in 2004 to 3,065 MTOE in 2014, where 47% of that amount was consumed by OECD countries (BP, 2015). The rapid growth in natural gas consumption has been attributed to the following factors (MIT, 2011):

1. The use of hydraulic fracturing technology enabled the profitable recovery of large shale gas reserves in the USA at energy-equivalent prices lower than coal's.
2. Rising oil prices (over $100 per barrel) provided an incentive for using alternative fuels for transportation and manufacturing processes.
3. Awareness of climate change and stricter enforcement of environmental restrictions enhanced the advantage of natural gas as a cleaner alternative to coal and oil. Natural gas emits about 50% CO_2 per MWh when compared to coal or oil.
4. Development of high efficiency and low cost CCGT plants.

3.3 Natural gas transportation and storage

Due to its gaseous form, natural gas can only be economically transported via pipelines and, more recently, as liquefied natural gas (LNG). Both have limitations (Alterman, 2012):

- Transportation via pipelines is limited to destinations in which pipelines are available. As a result, the supplier and the consumer are interdependent. In addition, interstate pipelines often need to cross a transit country. Transit countries require transition costs and may sometimes resist the transition entirely or for a limited time (Shaffer, 2013). Transmission by pipeline across seas and oceans is challenging and expensive, currently limited to 2,000-3,000 miles.
- Transportation via LNG requires costly liquefaction and gasification, as well as costly shipment and port fees. The large investment in infrastructure for LNG often requires long-term contracts to justify the investment which, in turn, limits the competition in LNG supply (Ebinger et. al, 2012).

The gaseous form of natural gas limits storage alternatives (Alterman, 2012). Storage requires large volume and leakage prevention. The majority of the gas is stored in depleted gas reserves, with smaller amounts stored in aquifers and salt caverns. Some of the stored gas cannot be subsequently recovered because of the minimal pressure requirement.

Natural gas is stored when prices are low or when demand is low. It can be extracted when prices rise and/or when the demand for gas rises. Hence, it is stored during the summer when there is no heating demand and extracted from storage in the winter when the demand increases (Geman and Ohana, 2009).

3.4 Global natural gas markets

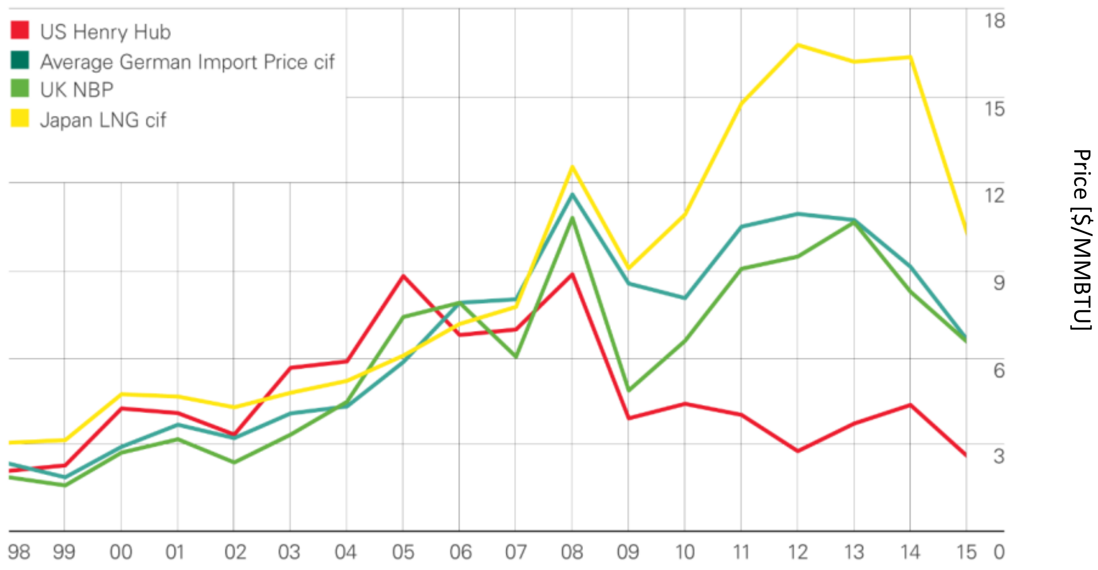
There are four distinguished global markets for natural gas (Melling, 2010; MIT, 2011; Alterman, 2012):

- **The US market**[13] – a highly deregulated and deep market comprising major trading hubs. The regional natural gas prices obey the 'law of one price' and reflect the spot price at the Henry Hub in Louisiana, the delivery point of the US natural gas futures contracts.
- **The UK market** – a deregulated and flexible market. The UK's gas price is set at the National Balancing Point's (NBP) virtual market.
- **The Continental European market** – gas is supplied mainly by Russia, the Netherlands and Norway under long-term contracts indexed to the price of oil. The difference between the contracted amount and the actual use is transacted on the spot market.
- **The Asian market** – there are no on-shore hubs. Prices are set by long-term LNG contracts with some spot LNG trading in Japan and Singapore.

Unlike crude oil with one global price, natural gas has prices that vary substantially by market, particularly in the last decade (see
Figure 3-2). These price differences reflect the different price settlement arrangements. Natural gas prices in the USA and the UK reflect the spot markets' supply and demand conditions. In Asia and Continental Europe, prices are set by long-term contracts mainly indexed to the oil markets (Alterman 2012). Furthermore, the price differences occur due to the limitation of gas transportation and storage (Geman and Ohana, 2009).

[13] www.EIA.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/MarketCenterHubsMap.html

Figure 3-2: Natural gas prices (1998-2015)



Source: BP (2015)

3.5 Natural gas price volatility

The annual price volatility of a commodity is commonly based on its daily price changes (in percentages) over a one-year period (Regnier, 2007; Roesser, 2009). Eydeland and Wolyniec (2003) define the annualized volatility σ as follows (page 82, eq. (3.9)):

$$\sigma = \sqrt{\frac{1}{T-1}\sum_{i=1}^{T}\left(\frac{logP_i - logP_{i-1}}{\sqrt{t_i - t_{i-1}}} - \frac{1}{T}\sum_{i=1}^{T}\frac{logP_i - logP_{i-1}}{\sqrt{t_i - t_{i-1}}}\right)^2},$$

where $\{P_i\}$ denotes the time series of historical prices observed at times t_i, $i = 0,...,T$, 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 the number of calendar days (365) or the number of trading days (250).

Figure 1-1 shows that the US daily natural gas price data have been exhibiting high volatility since the 1978 deregulation of the 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

LNG capacity. Natural gas storage is limited to depleted reservoirs, salt formations or LNG tanks. When natural gas production is disrupted or demand spikes, natural gas prices surge (Alterman, 2012). Volatility is further magnified by low inventory (Geman and Ohana, 2009).

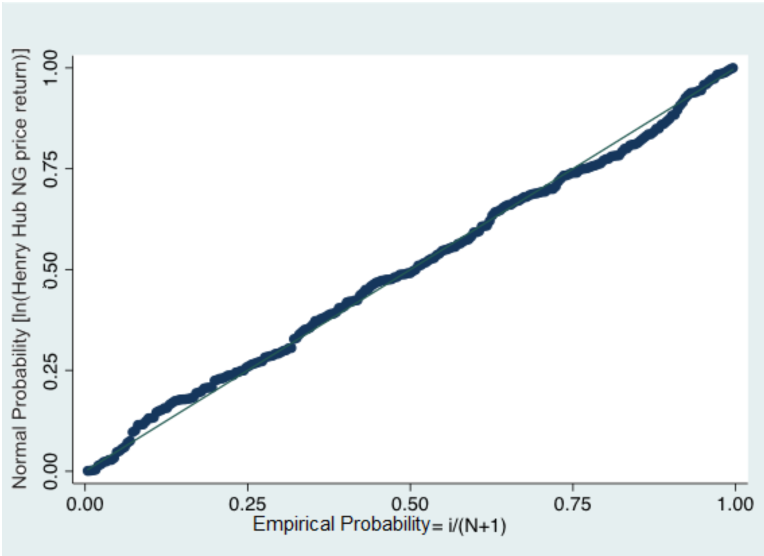
High natural gas price volatility implies that in a competitive electricity market, a natural gas-fired generation plant's cash flow is highly uncertain; and this uncertainty may be further magnified by electricity demand uncertainty.[14] The plant's fuel cost risk limits its owner's ability to obtain project financing and discourages capacity investment which, in turn, may cause electricity price spikes during periods of high demand (BPC, 2011).

Figure 3-3 depicts the fit of $ln\frac{c_t^G}{c_{t-1}^G}$ to a normal distribution, where $\mathrm{c}_\mathrm{t}^\mathrm{G}$ = daily per MWh fuel cost during January 2004 to December 2014 = the daily Henry Hub price times a constant heat rate of 6.44 MMBTU per MWh, and $\mathrm{c}_{\mathrm{t}-1}^\mathrm{G}$ = per MWh fuel cost on the previous day. It shows that $ln\left(\frac{c_t^G}{c_{t-1}^G}\right)$ is normally distributed, corroborated by the Jarque-Bera normality test and documented by Pilipovic (1997) and Geman (2005).

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

Figure 3-3: Fit of the daily change of the gas price to a normal distribution (2004-2014)

$\ln \frac{c_t^G}{c_{t-1}^G}$



The annualized volatility of the natural gas price during 2004-2014 ranges from 30% to 120% (with a value of about 100% in 2014). The implication of an annualized volatility of 100% is that over a period of one year there is a 67% probability that the price of natural gas will change by 100%[15].

3.6 The UK's natural gas market

3.6.1. UK gas supply and consumption

The UK is currently facing a decline in the local natural gas supply and an increasing dependence on imports (see

Figure 3-4) (EIA statistics; Alterman 2012):

- The production in the North Sea peaked in 2000, and has been declining ever since.
- In 2003, the UK became dependent on imports from continental Europe, mainly via the UK–Belgium pipeline.

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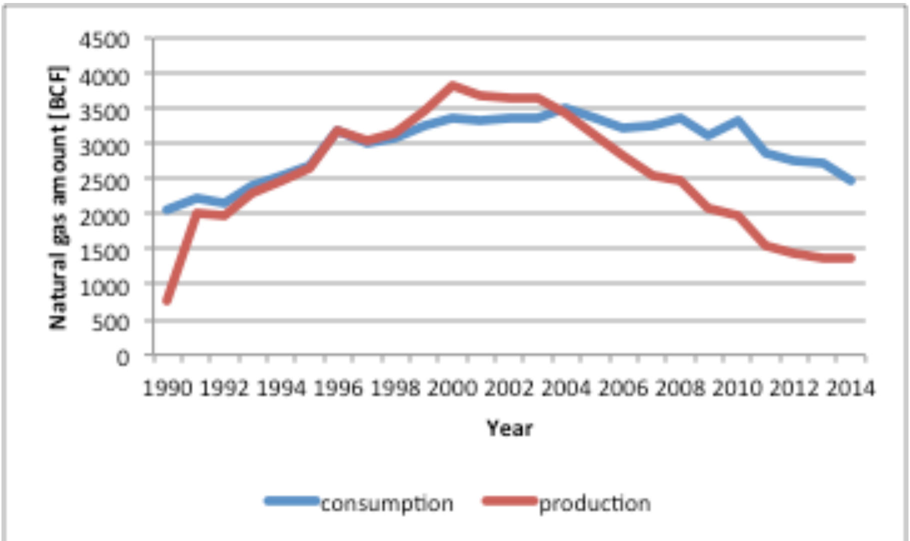
[15] An annualized volatility of 100%, implies a daily standard deviation of $100\%/\sqrt{365}$=5.2%. That is, a probability of 67% that over one day the price will change by 5.2%.

- In 2007, a new pipeline from Norway (Langeled) to the UK was opened, thereby increasing the natural gas capacity available to the UK.
- The LNG inventory capacity on the Isle of Grain was constructed in 1982 to store excess gas supply. In 2005, it was converted to an LNG import facility to meet the growing share of British imports[16]. The LNG imports started to grow in 2008, as new LNG export facilities came online in Qatar, Yemen and Nigeria. LNG supply to the UK increased at that time because the demand for LNG in the USA decreased, due to soaring shale gas supply, and the demand in Asia decreased as a result of the financial crisis (Alterman 2012).

Figure 3-4: UK natural gas production and consumption (1990-2014)



Source: Retrieved from http://www.EIA.gov/opendata/index.cfm

3.6.2 UK natural gas market structure

The UK's gas market was privatized and has been open to competition since 1986 (OECD, 2002). The British Gas Company (BG) was established in 1972 as a government-owned, vertically integrated monopoly. BG owned all the British onshore gas facilities, including

[16] See Hydrocarbons-technology.com

the national pipeline system, and had exclusive long-term contacts with all off-shore producers. Initial attempts to open the British market to competition took place in 1982. The attempts failed, however, because BG was unwilling to surrender any of its exclusive purchasing agreements or allow access to the pipeline system.

The Gas Act of 1986 finally enabled the liberalization of the market (OECD 2002; Heather, 2010; Lewis, 2015), causing the following changes:

- BG was privatized.
- Tariffs were set by a newly established regulator - the Director General of Gas Supply (DGGS).
- BG was given an exclusive permit to sell gas to small customers (70% of the market). Other suppliers were allowed to enter the market and sell gas to industrial consumers.
- The DGGS ensured access of private suppliers to the pipeline grid and set the transmission price.

Competition started to develop in 1991 (Lewis, 2015), requiring the following regulatory interventions (OECD 2002):

- BG was limited by an exclusive permit to sell gas to a smaller share of the market.
- BG's exclusive supply contracts with off-shore suppliers were limited to 90% of the production in the North Sea.
- The regulator prohibited discrimination of transmission tariffs.

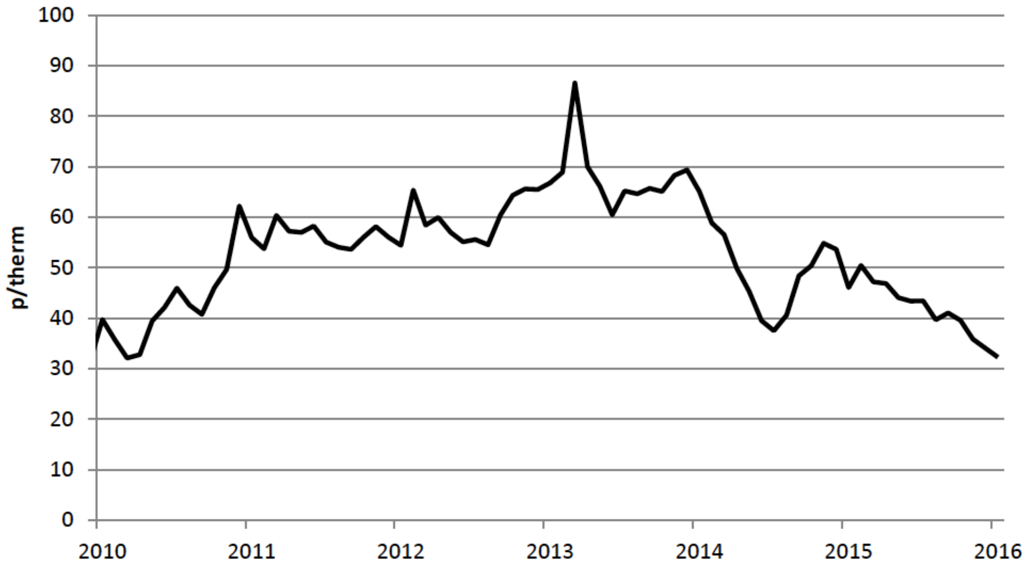
OECD (2002) indicates that the emergence of competition has shortened the length of the contracts; weakened the link of the price of gas to the price of oil; and reduced the "take or pay" requirements. Eventually, the price of gas and of gas transport became separated, and real competition among suppliers emerged. Finally, a spot market and a forward market for gas evolved, and today's prices reflect the interaction of market demands and supplies.

3.6.3 UK natural gas price trend

Increasing dependence on imports and limited storage have led to an increasing wholesale price in the British market (see Figure 3-5; Ofgem, 2016). Recent price drops in global electricity markets (BP, 2015) have moderated the long-term price increase in the British market. Alterman (2012) indicates the main factors affecting natural gas prices in the UK:

- Weather and seasonality - Approximately 60% the consumption is used for heating. Therefore, temperature during the winter has a significant effect on local demand.
- Storage – Similarly to the US market, storage is used for mitigating variations in demand. However, storage capacity represents only 4% of the annual consumption and 75% of the storage capacity is concentrated in one site. Hence, storage only minimally mitigates demand and supply variations (Alterman 2012).
- Import capacity – Due to the lack of sufficient storage capacity, import capacity is needed in order to meet demand spikes. Import capacity was small in the beginning of the 21st century, but has expanded in recent years, thanks to the addition of the Langeled pipeline from Norway, and the conversion of the infrastructure at the Isle of Grain to importation.

Figure 3-5: Monthly average wholesale gas prices (penny/therm) in the UK market



Source: OFGEM, 2016

Note: 1 therm = 10 MMBTU.

The price of natural gas in the UK is linked to the price in Continental Europe which, in turn, is tied to the price of oil. It has declined since 2014, due to the global oil price decline and the decline in the global demand for natural gas (Ofgem, 2016).

3.7 The US natural gas market

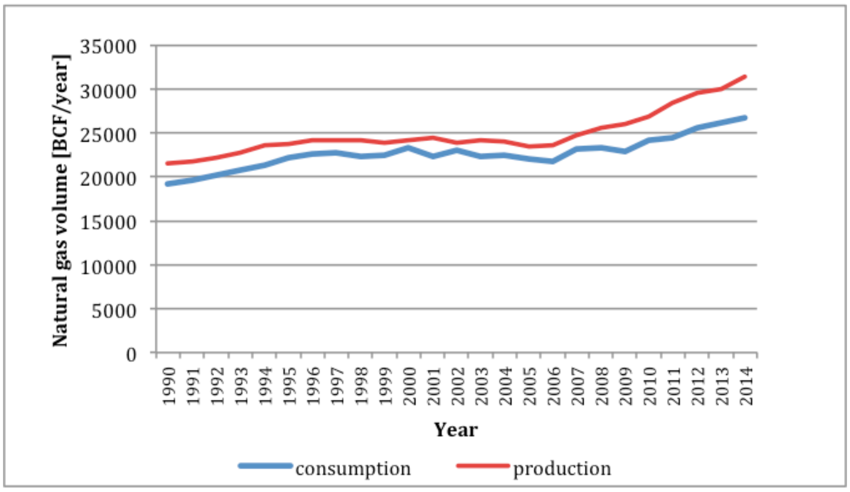
3.7.1. US gas supply and consumption

Figure 3-6 portrays the US gas supply and consumption. Over the past decade, the USA has become a net natural gas exporter, thanks to the rapid increase in local natural gas discoveries and the use of hydro fracking. The share of shale gas in overall US natural gas production increased rapidly from 24 trillion cubic feet (TCF) in 2004 to 32 TCF in 2014 (retrieved from EIA Energy Statistics section[17]). The rapid increase of unconventional gas

[17] https://www.eia.gov/beta/international/data/browser, accessed 2017

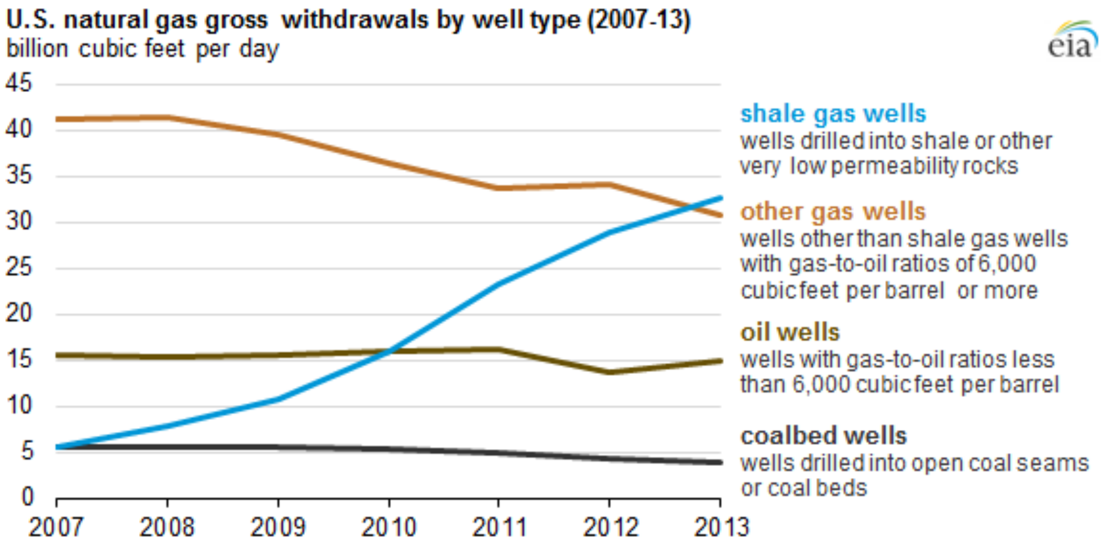
production enabled the USA to meet the country's entire demand with local supply, as shown in Figure 3-6 below (EIA, 2013).

Figure 3-6: US natural gas supply and consumption



Source: Retrieved from www.EIA.gov, International Energy Statistics section

Figure 3-7: US natural gas production by source



Source: (EIA 2013)

3.7.2 US natural gas market structure

The consumption of natural gas in the USA increased rapidly from 1950 to 1970, as a result of the development of an interstate pipeline system. The Federal Power Commission (FPC[18]) regulated gas prices, and provided certificates for building new pipelines (MIT 2011). Following the energy crisis of 1974, consumers sought to switch some of their needs to natural gas. However, gas production did not develop fast enough to meet the increasing demand, due to price caps and tight regulations. As a result, a perception of gas scarcity emerged. Congress passed the Natural Gas Policy Act of 1978 (NGPA), giving the federal regulator the authority to regulate intrastate wholesale prices and ensure supply to high priority agricultural and industrial consumers. Congress passed the Power Plant and Industrial Fuel Use Act (FUA), outlawing the building of new natural gas capacity intended for the electricity sector's use. The act was repealed in 1987 (MIT 2011; Von Hirschhausen 2008; Joskow, 2013).

Since 1987, the US natural gas market has expanded rapidly, due to the development of low-cost CCGT plants, deregulation of wholesale prices, and the development of offshore drilling. Most of the electricity capacity that was built in the USA after the repeal of the Fuel Use Act was gas-fired. Consequently, the rapid development of demand for natural gas in the USA created a perception of long-term gas shortage and the price of natural gas increased. These trends created an incentive for the development of LNG import facilities in the USA (MIT 2011; Von Hirschhausen, 2008; Joskow, 2013). The recent increase in natural-gas production due to shale gas production has obviated the need for gas import and raised the possibility of LNG export (Ebinger et. al, 2012). US exports are expected to grow, but will probably face global competition that may affect price (Boersma et al., 2015).

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[18] FPC is the former name of the Federal Energy Regulatory Commission (FERC)

3.7.2. US natural gas price trends

The competitively set natural gas price in the USA is affected by the following factors (Geman and Ohana, 2009; Alterman, 2012):

- **Extreme weather events** (i.e., hurricanes). Extreme weather in the beginning of the last decade caused supply disruptions and, consequently, price spikes. The severity of this factor has declined over time, along with the share of offshore drilling.
- **Storage levels.** Gas is injected into storage during the summer and withdrawn from storage during the winter to compensate for the demand for heating gas during the winter. Storage capacity represents about 18% of the annual demand and is distributed among various locations. In the event of cold temperatures at the beginning of the winter, withdrawal rates of natural gas are likely to increase, leading to a perception of scarcity and higher gas prices.
- **LNG import capacity.** In past years, LNG import capacity indicated the potential of supply levels. Today, almost all the supply is provided by the local market or by pipelines from Canada. Therefore, the importance of LNG import capacity has become negligible.
- **LNG export.** As LNG exports from the USA increase, natural gas prices likely rise. However, rising prices would reduce the US exports of natural gas. Therefore, exports may only increase the local price up to a limited threshold (Ebinger, 2012).

Figure 3-8: US (Henry Hub) monthly natural gas price: 2001-2015

The price of natural gas in the USA has been declining since 2008. This decline is attributed to the rapid development of shale gas, which increased the supply of gas and replaced the need for imported liquid gas, as well as the global oil price drop that began in 2014.

3.8 Israel’s natural gas market

3.8.1. Israel’s natural gas supply and consumption

Up until 1999, Israel had no indigenous supply of fossil fuels. In 1999, two reserves (Noa and Mary B) totaling 32 billion cubic meters (BCM) were discovered in the Yam Thetis area in the Mediterranean Sea. The gas production from these reserves was purchased by the Israeli Electric Corporation (IEC) which, for the first time, could use gas to fuel its generation plants. The two reserves came on line in 2004 and became depleted in 2013 (Shaffer 2011).

Starting in 2009, large reserves were found offshore (MNIEWR; Shaffer 2011):

- In January 2009, the Tamar field was discovered 90 km west of Israel’s coast. The estimate of Tamar’s proved reserves is 283 BCM[19]. This field came on line in April 2013.
- In April 2009, the Dalit field was discovered 40 km west of Israel's coast, with proven reserves of 7-14 BCM.
- In June 2010, the largest field so far, Leviathan, was discovered about 130 km off the shore of Israel with proven reserves of 510 BCM.

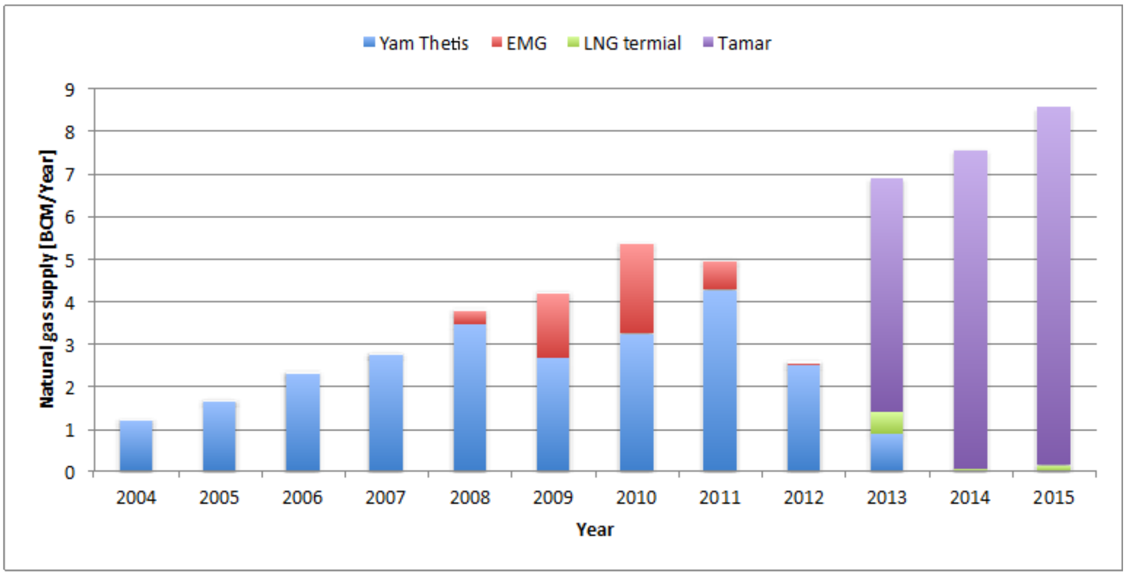
In 2008, the Eastern Mediterranean Gas and Oil Company (EMG) signed a 15-year contract to export 25 BCM from Egypt to Israel through a pipeline from El-Arish in the Sinai Peninsula to Ashkelon. The pipeline suffered from repeated disruptions by terrorist acts and, consequently, Egypt canceled the contract with EMG in 2013 following the fall of the Mubarak regime (Shaffer, 2011; PUA, 2015). In 2011, the government of Israel decided to build a buoy-based LNG receiving terminal off the Hadera coast, to offset the decline of Yam Thetis and the disruptions of the Egyptian supply. The LNG terminal diversifies the gas resources and increases Israel's supply reliability (MNIEWR).

[19] Retrieved from http://www.nobleenergyinc.com

Consumption of natural gas in Israel started in 2004, and up until 2013 was available only to the electricity sector. The discovery of the Tamar Field in 2009 (and, later on, Leviathan in 2011) provides great potential for further increasing the share of natural gas in Israel's generation mix and shifting from diesel/fuel oil to gas in the industrial sector. As of 2015, a pipeline infrastructure is being built to enable supply to industrial users.

In 2014, 7.6 BCM were consumed by the Israeli market, out which about 6 BCM were consumed by electricity generators. Consumption is expected to grow in the future due to rising electricity demand, displacement of coal consumption by electricity generation, and industrial users' fuel switching from liquid fuels to gas (MNIEWR: PUA, 2015).

Figure 3-9: Israel's natural gas consumption growth and supply sources



Source: Israeli Natural Gas Authority, 2015

Figure 3-9 depicts the decline of the Yam Thetis (YT) reservoir in 2012-2013, the disruptions (and, subsequently, elimination) of the EMG supply in 2011-2012, and the beginning of natural gas extraction and sales from the Tamar reservoir in 2013. It also demonstrates the continuous demand growth for natural gas by the local market, excluding the years 2011-2012, during which natural gas supply was unavailable.

3.8.2. Israel's natural gas market structure

The Natural Gas Sector Law (2002) designed the newly established natural gas market in Israel through vertical separation and unbundling.

The Natural Gas Authority in the Israeli Ministry of Energy and Water Resources regulates the activity in the natural gas sector. The authority is in charge of "safety, long-term strategic planning to guarantee a continuous supply of natural gas, licensing and supervision of natural gas licensees, establishing tariffs and criteria for the provision of services, arbitrating disputes and defining arrangements between the market players, and investigating consumer complaints against licensees." (MNIEWR).

The government leased Israel's natural gas reservoirs to private companies. Government resolution no. 476 aims to enable competition in the supply segment[20]. The resolution exempts lease holders from being considered a cartel in accordance with Article 52 of the Antitrust Law 5748-1988, in exchange for transferring their rights in other gas reservoirs in the Mediterranean basin. According to the 1952 Petroleum Law, companies receive a three-year exploration license. If a field is discovered, the company is granted a production permit for 30 years. The companies are required to pay 12.5% in royalties and allow the government of Israel to buy any required amount at a competitive price. Tasked to reconsider the royalties, the Sheshinski Committee (Sheshinski, 2011) recommended a progressive levy, which would take effect after a company's recovery of 150% of its investment.

Forbidden to hold gas supply licenses, the transmission pipeline is constructed and operated by the government-owned Israeli Natural Gas Lines regulated by the Natural Gas Authority. The distribution pipelines are constructed and operated by privately-

[20] Israeli Government Resolution no. 476 "A framework to increase the quantity of natural gas produced from the Tamar natural gas field and rapid development of the natural gas fields Leviathan, Karish and Tanin, and additional natural gas fields", August 2015.

See http://www.pmo.gov.il/secretary/govdecisions/2016/pages/dec1465.aspx owned companies, chosen via franchise bidding and supervised by the Natural Gas Authority.

3.8.3 Israel's natural gas price trends

The supply of gas has not yet been opened to competition; therefore, natural gas prices in the market are set by long-term contracts:

- An IEC contract was signed in 2012 and is indexed to the US CPI with a basic price of $5/MMBTU (PUA, 2015).
- The IPPs' contract has a basic price of $5.66/MMBTU, which is indexed[21] to the electricity price.
- Small industrial users can purchase gas from suppliers at a price indexed to the Brent price.

Finally, government resolution no. 476 allows the continuance of current contracts, with the requirement of the lease holders selling gas to new customers at a price reflecting the average price of these contracts.

[21] PUA, Resolution 1 – Meeting 377 – Principles for recognizing costs incurred due to natural gas acquisition agreements, June 2012.

4. Literature review

This chapter reviews the academic and professional literature on capacity investment in regulated and competitive electricity markets. Sections 4.1 and 4.2 summarize the literature on capacity investment in monopolistic markets and competitive oligopolistic markets, respectively. Section 4.3 reviews the literature on the effect of uncertainty on capacity investments. These sections provide the framework for Chapter 5. Section 4.4 reviews the literature on gas supply interruptions and dual fuel capability. This section provides the framework for our dual fuel model, discussed in Chapter 7. Section 4.5 overviews the literature on generation mix in competitive markets, providing the framework for our modeling of the effect of uncertainty on capacity mix in Chapter 8.

4.1 Capacity planning in monopolistic markets

Prior to the 1980s, the electricity sectors in most regions of the world were organized as vertically integrated monopolies. Generation expansion models were used for the planning of the electricity sector (Anderson, 1972; Levin et al., 1985). These models were designed to find the minimal present value of the cost of meeting projected future demand over a long planning horizon (e.g., 20 years), subject to such constraints as fuel availability, resource adequacy, reliability, and emission limits. Anderson (1972) reviews several optimization models that determine the least-cost cost investment in a vertically integrated market. All optimization parameters were assumed to be deterministic, despite the stochastic nature of future demands and costs. Levin et al. (1985) extend the capacity investment models 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.

4.2 Equilibrium and capacity investment in oligopolistic electricity markets

Restructuring of the electricity sector in the 1990s to introduce competition in the generation segment required a new modeling approach. Capacity expansion was no longer the result of total cost minimization. Rather, interactions among profit- maximizing firms became regulators and academics' focus of analysis. The competitive market models that accommodate these developments fall into two main classes: Nash 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., 2008b). Other models use Bertrand competition, where the strategic variable is the electricity price (Bun et. al, 2003), or a Stackelberg game, where a market leader first decides the electricity price or quantity, while accounting for the subsequent reaction of the followers (Spulber, 1981). Assuming that the fuel cost is deterministic and known, several studies discuss the optimal capacity choice of firms under market competition (von der Fehr and Harbord, 1997; Murphy and Smeers, 2005; Tishler et al., 2008b). Hobbs (1994) discusses optimization planning methods to account for fuel cost uncertainty via Monte Carlo simulations.

4.3 The effect of uncertainty on capacity investment in competitive markets

Hartman (1972) studies the effect of uncertainty on investment decisions by a profit-maximizing firm operating in a competitive market, showing that rising marginal cost volatility tends to increase capacity investment. Ryu and Kim (2011) study the effect of cost uncertainty on equilibrium in a duopoly market, finding that equilibrium production can increase or decrease, depending on each firm's conjecture about the rival's uncertain cost. Siddiqui and Maribu (2009) assess electricity market equilibrium under uncertain availability of generation units and costs, using real options to show that uncertainty increases the value of the investment opportunity. Finally, Tishler et al. (2008b) and Milstein and Tishler (2012) study capacity investment under demand uncertainty in a Cournot market setting, showing that capacity underinvestment is inevitable in competitive market and leads to price spikes in equilibrium.

Financial theory offers a different line of inquiry. Pindyck (1991) and Dixit and Pindyck (1994) use the real option framework to value investment opportunities with uncertain cash flow. Their framework applies to investments, such as power plants, which are irreversible but can be delayed. The authors argue that the net present value (NPV) method in the presence of uncertain cash flow is incorrect because the NPV method ignores the opportunity cost of investing now, instead of awaiting more information. An important result is that higher volatility leads to higher option value (Pindyck, 1991). However, the real option theory is limited to a competitive market where the decision of a single firm does not affect the equilibrium price.

4.4 Dual fuel capability

Dual fuel capability enhances the firm's risk management strategy by mitigating the risk of gas supply interruptions and natural gas price spikes. Gas supply interruptions can result from various causes:

A. **Pipeline capacity constraints or limited operational flexibility** - Newell et al. (2014) indicate that firms in areas characterized by repeated gas supply interruptions, due to capacity constraints or limited operational flexibility, would invest in dual fuel capability. Adam Sieminski's testimony before the US House of Representatives (Representatives, 2013) elaborates on the reasons for gas supply interruptions in the New England region, and discusses various solutions, including dual fuel capability along with other solutions such as demand response, pipeline expansion, and LNG peak contracts.

B. **Geopolitical supply interruptions** - Shaffer (2013) studies various gas supply interruptions in the international arena, with a detailed analysis of the Egyptian curtailment of supply to Israel and Jordan in 2011, and the Russian–Caucasian supply cutoff of 2012. The author concludes that the probability of supply interruption increases when the dependence of the supplier and the buyer on the contract is asymmetric (i.e. one party heavily depends on the pipeline while the other party does not). Silve et al. (2010) study the possibility of a dual fuel capability as a means of improving Bulgaria's electricity sector's fuel supply security. The authors indicate that diesel back-up is common in countries with insecure gas supplies such as Singapore, the UK and Spain. The study demonstrates the advantages of dual fuel capability relative to increased gas pipeline capacity.

C. **Weather-related supply cutoffs** – Alterman (2012) studies the effect of weather on natural gas supply interruptions, and concludes that the risk of supply cutoffs increases if storage capacity is limited, as was the case in the UK.

Dual fuel capability can mitigate gas supply risk. The additional investment needed to establish a dual fuel capability includes storage facilities, adequate fuel inventory, and adaptation of the generation units to air quality compliance when using the secondary fuel (e.g., fuel oil). Overall, the introduction of dual fuel capability may increase the annual capacity cost by 10-20 percent (Newell et al. 2014, Silve et al., 2010). Firms in a competitive oligopoly are therefore required to decide whether to continue their exposure to natural gas price spikes and gas supply interruptions or mitigate the risk by investing in dual fuel capacity.

4.5 Capacity mix

Focusing on the possibility of underinvestment in capacity in competitive electricity markets, several studies discuss the optimal capacity choice of firms in a single fuel competitive market, assuming deterministic fuel prices (Andersson and Bergman, 1995; Fehr and Harbor, 1997; Borenstein and Bushnell, 1999, Tishler et al., 2008b). They conclude that under-investment is a rational (non-abusive) behavior of profit-seeking firms. Capacity mix in competitive markets is studied, among other papers, by Murphy and Smeers (2005), Joskow (2006) and Milstein and Tishler (2012). Murphy and Smeers (2005) compare open vs. closed loop models and conclude that baseload players in a mixed capacities market can take advantage of their position to expand their market share. Milstein and Tishler (2012) conclude that baseload firms are likely to profit much more than peaking firms, and that price spikes are smaller and less frequent when more than one generation technology is used to generate electricity.

The role of renewable technologies in the optimal capacity mix is assessed and discussed by several authors. De Jonghe et al. (2011) find that variability of wind generation increases the share of flexible generation in the capacity mix. Milstein and Tishler (2012, 2015) study the integration of solar energy in the capacity mix and conclude that a larger share of PV capacity increases price spikes and the average annual per KWh retail price. Larson et al. (2003) implement a technology mix model for the Chinese market, concluding that a cleaner strategy would not induce a higher overall energy cost. Diakoulaki and Karangelis (2007) discuss the optimal technology mix for the Greek market, finding that that the option with the highest share of renewable energy provides the best economic, technical and environmental performance for the Greek market.

Awerbuch and Yang (2007) assert that given the various risks related to energy generation options, energy planning should valuate generation portfolios not only by their total costs, but also by their overall risk. The authors adapt the Capital Asset Pricing Model (CAPM) to the energy sector and find the “efficient frontier” of possible portfolios that minimize portfolio risk, given a desired cost level. The risk of each possible portfolio incorporates the fuel cost risk (as measured by its variance), as well as other risks. The portfolio risk also accounts for the correlations among the portfolio’s various generation options. The portfolio approach was applied to several markets. Zhu and Fan (2010) implement portfolio theory to the Chinese market and conclude that diversification, such as an increased share of nuclear energy, can limit the cost-risk of China’s portfolio. Similarly, Arnesano et al. (2012) implement portfolio theory in the Italian market and show that a larger share of renewable energy can reduce price risk.

Portfolio and real options theories analyze investment decisions under risk conditions (Pindyck, 2004). However, both theories assume that market participants are price takers. Therefore, they provide limited insights into investment decisions under uncertainty in an oligopolistic market.

5. Fuel price volatility and capacity investment

5.1 Introduction

This chapter builds on Tishler et al. (2008) and examines the effect of uncertain natural gas prices, and therefore fuel costs, on capacity investment, electricity production and prices, consumer surplus and IPP profits in a competitive electricity market.

Building a new power plant is a slow process, requiring a long lead-time. However, daily fuel costs and electricity demands are volatile. Installed capacity aims to serve projected daily demands, implying potentially large idle capacity during many hours of the day in a given year. When the daily realized peak demand exceeds the available capacity, the daily electricity price increases to curb the excess demand. Hence, daily hourly spot electricity prices fluctuate substantially within a day and across seasons (Bessembinder and Lemmon, 2002; von der Fehr et al., 2005; Tishler et al., 2008b).

To explore the inter-connection among capacity expansion, electricity price and fuel cost volatility, we develop a two-stage, closed-loop model to capture the lead-time in capacity construction, daily fluctuating fuel costs, and short-term demands met by installed capacity. In the first stage, only the probability distribution function of future daily fuel costs is known. Profit-seeking IPPs maximize their expected profits by determining the amount of capacity to be constructed. In the second stage, once daily fuel cost and electricity demand are known, each IPP selects its daily output up to the capacity built in the first stage via the Cournot model.[22] The daily output, in turn, determines the equilibrium market price.

[22] The assumption of Cournot competition is common in the electricity market reform literature (e.g., Wolfram, 1999; Borenstein et al., 2002; Murphy and Smeers, 2005; Tishler et al., 2008b).

5.2 The model

Solved recursively, our two-stage model assumes an oligopoly market with *N* identical IPPs (firms) operating daily in a period of *T* days. We first determine the equilibrium quantities, the equilibrium price and the profits in Stage 2. We then determine each firm's optimal capacity to be built in Stage 1.

The market's inverse demand function P_t on day *t= 1, …, T* is assumed to be linear:

[5.1] $$P_t = a - bQ_t,$$

Where *a > 0*and *b> 0,* $Q_t = \sum_1^N Q_{it}$ = total electricity generated by *N* firms, and Q_{it} = electricity generated by firm *i = 1, …, N.*

For simplicity's sake, variable costs other than those for natural gas are assumed to be zero[23]. Following Newbery (1998), Besanko and Dorazelski (2004), Murphy and Smeers (2005) and Tishler et al. (2008b), we assumed a linear amortization of the debt service; thus, the cost function of electricity generation of firm *i* on day *t* is:

[5.2] $$C(Q_{it}, \mathrm{K}_i) = \frac{\Theta}{T} K_i + c_t Q_{it},$$

where *Θ*= marginal capacity cost ($/MW-year) applicable to the *i-th* firm's capacity K_i (MW), and c_t = per MWh fuel cost ($/MWh) on day *t* = generation heat rate (MMBTU/MWh) × natural-gas price ($/MMBTU) on day *t*. We also assume that $c_t < a$ because P_t = *a* at Q_t = *0,* implying that *a* is the price that would completely choke off the market demand.

Further, let c_o = initial per MWh fuel cost at the beginning of *t = 1*. Following Pilipovic (1997) and Geman (2005), we assume that $ln\left(\frac{c_t}{c_{t-1}}\right)$ is normally distributed with mean μ and variance $\sigma_{c_t}^2$. Thus, $\frac{c_t}{c_0}$ has a log-normal distribution[24], with parameters μt and $\sigma_{c_t}^2 t$*:*

[5.3] $$ln\frac{c_t}{c_0} \sim N(\mu t, \sigma_{c_t}^2 t) \leftrightarrow \frac{c_t}{c_0} \sim lnN(\mu t, \sigma_{c_t}^2 t)$$

[23] The assumption of a zero non-fuel cost is later relaxed in our empirical illustration in Section 6.

[24] See section 3.5 on the relevance of the lognormal distribution to natural gas prices.

$$[5.4] \qquad \tilde{g}\left(\frac{c_t}{c_0}|\mu t, \sigma_{c_t}^2 t\right) = \frac{c_0}{c_t \sigma_{c_t}\sqrt{2\pi t}} e^{-\frac{1}{2}\frac{\left[ln\left(\frac{c_t}{c_0}\right)-\mu t\right]^2}{\sigma_{c_t}^2 t}}$$

The rest of this section uses σ_{c_t} to measure volatility of per MWh fuel cost in period[25].For expositional simplicity, denote $\tilde{g}\left(\frac{c_t}{c_0}|\mu t, \sigma_{c_t}^2 t\right) \equiv g(c_t)$.

5.3 Stage 2 solution: Equilibrium generation and price

Assuming Cournot competition, each of the *N* firms sets Q_{it} in Stage 2 to maximize its profits, π_{it} on day *t*, given its available capacity K_i, c_t and Q_{jt} $(j = 1, \dots, N; j \neq i)$. Each firm's optimization problem is:

$$[5.5] \qquad \max_{Q_{it}} \pi_{it} = (P_t - c_t)Q_{it}$$

$$s.t.\ Q_{it} \leq K_i, Q_{it} \geq 0.$$

Inserting the demand function in equation [5.1] into equation [5.5] yields:

$$[5.6] \qquad \max_{Q_{it}} \pi_{it} = (a - b \cdot \textstyle\sum_i Q_{it} - c_t) \cdot Q_{it}$$

$$s.t.\ Q_{it} \leq K_i, Q_{it} \geq 0.$$

The first-order condition is:

$$[5.7] \qquad a - b \cdot (2Q_{it} + Q_{-it}) - c_t = 0,$$

where $Q_{-it} \equiv \sum_{j \neq i} Q_{jt}$. The optimal solution is:

$$[5.8] \qquad Q_{it}^* = \begin{cases} K_i, & if 0 \leq c_t < a - 2bK_i - bQ_{-it} \\ \frac{1}{2b}(a - c_t - bQ_{-it}), & if \quad a - 2bK_i - bQ_{-it} \leq c_t < a \end{cases}$$

Inserting the optimal solution into the inverse demand function [5.1] yields the optimal price solution. This solution is similar to the one in Tishler et al. (2008b).

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[25] Assuming risk-neutral investment, $\mu t = rt - \frac{\sigma_{c_t}^2 t}{2}$, where *r* = riskless interest rate (Lee et al., 2010).

5.4 Stage 1 solution: Optimal capacity

In Stage 1, each firm determines its optimal capacity, given the distribution function $g(c_t)$. The optimal capacity maximizes the sum of the expected daily profits over the operation period minus the capacity's construction cost:

$$[5.9] \qquad \max_{K_i} \left[\sum_{t=1}^{T} e^{-rt} \left(E(\pi_{it}|K_i) - \frac{\Theta}{T} K_i\right)\right].$$

The expected variable profit of the *i-th* firm on day *t* is:

$$[5.10] \qquad E(\pi_{it}|K_i) = \int_0^a g(c_t) \cdot (P_t - c_t) \cdot Q_{it} dc_t.$$

Inserting the equilibrium solution of Stage 2 (equation [5.8]) into equation [5.10] yields:

$$[5.11] \qquad E(\pi_{it}|K_i) = \int_0^{a-2bK_i-bQ_{-it}} g(c_t) K_i \cdot (a - bK_i - bQ_{-it} - c_t)\, dc_t + \int_{a-2bK_i-bQ_{-it}}^{a} g(c_t) \frac{1}{4b} (a - bQ_{-it} - c_t)^2 dc_t.$$

The first-order condition for optimal capacity is:

$$[5.12] \qquad 0 = \frac{\partial}{\partial K_i} \sum_{t=1}^{T} e^{-rt} \left[\int_0^{a-2bK_i-bQ_{-it}} g(c_t) K_i \cdot (a - bK_i - bQ_{-it} - c_t)\, dc_t + \int_{a-2bK_i-bQ_{-it}}^{a} g(c_t) \frac{1}{4b} (a - bQ_{-it} - c_t)^2 dc_t - \frac{\Theta}{T} K_i\right].$$

Applying the Leibniz rule to compute the derivative in equation [5.12] and assuming symmetry of the *N* firms (i.e. $K_1^* = \cdots = K_N^* = K^*$) yield the optimal capacity[26] condition:

$$[5.13] \qquad 0 = \sum_{t=1}^{T} e^{-rt} [\int_0^{c_{K^*}} (c_{K^*} - c_t) \cdot g(c_t) dc_t - \frac{\Theta}{T}],$$

where $c_{K^*} \equiv a - K^* \cdot b \cdot (N + 1)$, and K^* is the firm's optimal capacity.

The first-order condition given by [5.13] implies that the firm should add capacity, so long as the new capacity's present value of expected daily operating profits exceeds the capacity cost.

Since c_t is uncertain, building capacity K^* is equivalent to buying a put option with a strike price c_{K^*}. when $c_t > c_{K^*}$, equilibrium generation in Stage 2 is below the available capacity because the option is "out of the money". If $c_t < c_{K^*}$, the firm's equilibrium generation

[26] The optimal capacity satisfies the second-order condition for profit maximization.

increases to full capacity because the option is "in the money", with a per MWh profit of *(c_{K^*}–c_t) > 0.*

To ensure continuous, clear and uninterrupted readings of our models and results, the proofs of the propositions in the thesis are presented in the Appendix. Propositions 5-1 and 5-2 below characterize the optimal first-stage solution.

Proposition 5-1: *The marginal profit and optimal capacity of an expected profit-maximizing firm in oligopolistic competition increase with the volatility of c_t.*

Proposition 5-2: *An increase in the volatility of c_t causes:*

a. *An increase in the expected consumer surplus and expected profit in the optimal first-stage solution on day t.*
b. *A decline in the expected electricity price in the optimal first-stage solution on day t.*

Proof*:* See Appendix.

These results are valid for any finite number of firms, *N*, in the market. In chapter 9 (figure 9-3) we study an empirical example of a market with various values of *N*, and show that capacity increases with the number of firms and, for each number of firms in the market, it increases with the volatility of natural gas prices.

Note that a log-normal distribution implies that the probability of low c_t rises when σ_{c_t}increases, because the log-normal distribution is skewed to the left, with most of its mass occurring at low c_t values. Consequently, rising fuel cost volatility induces firms to increase their installed capacity, so as to improve their chances of benefiting from low generation costs. Consequently, electricity prices decline, enhancing consumer surplus. The fit of natural gas prices to the log-normal distribution is shown in figure 3-3 on page 39. Propositions 5-1 and 5-2 are valid under the log-normal distribution of the natural gas price and may not hold for other types of distributions.

Also note that a more price responsive (elastic) demand would increase the response to price volatility. Consequently, the value of the marginal capacity unit increases and optimal capacity would be larger when the absolute value of the price elasticity of demand is higher (see figure 9-4).

5.5 Optimal capacity with uncertain demand and uncertain fuel cost

This section extends the model to include demand uncertainty. Following Tishler et al. (2008b), the inverse demand function is now assumed to be:

[5.14] $$P_t = a - bQ_t + \varepsilon_t,$$

Where ε_t is a random variable with a distribution function $f(\varepsilon_t)$. We assume that ε_t and c_t are independent[27].

The solution of Stage 2 is given by:

[5.15] $$Q_{it}^* = \begin{cases} K_i, \ if \ \ (c_t - \varepsilon_t) \leq a - 2bK_i - bQ_{-it} \\ \frac{1}{2b}(a+\varepsilon_t - c_t - bQ_{-it}), \ \ if \ \ a-2bK_i - bQ_{-it} \leq c(c_t - \varepsilon_t)_t < a \end{cases}$$

In Stage 1, the optimal capacity maximizes the sum of the expected daily profits over *T* days, less the cost of capacity construction:

[5.16] $$\max_{K_i} \left[\sum_{t=1}^{T} e^{-rt}(E(\pi_{it}|g(c_t), f(\varepsilon_t)) - \frac{\Theta}{T}K_i)\right]$$

The expected operating profit of firm i on day *t* is calculated over all possible values of $(c_t - \varepsilon_t)$:

[5.17] $$E(\pi_{it}) = \int_{-\infty}^{\infty} f(c_t - \varepsilon_t) \cdot (P - c_t)Q_{it} \cdot d(c_t - \varepsilon_t).$$

Inserting the equilibrium solution of Stage 2 into equation [5.17], we find:

[27] The independence assumption is empirically reasonable because of the likely weak correlation between the electricity demand and the natural gas price, except for regions in which natural gas and electric heating are prevalent to the same extent. When such regions experience cold weather, both the natural gas demand and the demand for electricity may rise in tandem, thus resulting in a positive and possibly strong correlation between the demand for electricity and the natural gas price.

[5.18] $E(\pi_{it}) = \int_{-\infty}^{a-2bK_i-bQ_{-it}} f(c_t-\varepsilon_t)K_i \cdot (a-bK_i-bQ_{-it}-(c_t-\varepsilon_t))\, d(c_t-\varepsilon_t) + \int_{a-2bK_i-bQ_{-it}}^{\infty} f(c_t-\varepsilon_t)\frac{1}{4b}(a-bQ_{-it}-(c_t-\varepsilon_t))^2 d(c_t-\varepsilon_t),$

Taking the derivative of the objective function [5.16] w.r.t. K_i and using the Leibniz rule to compute the derivative, the first-order condition for the optimal capacity is:

[5.19] $0 = \sum_{t=1}^{T} e^{-rt}[\int_{-\infty}^{c_{K^*}} (c_{K^*} - (c_t-\varepsilon_t)) \cdot f(c_t-\varepsilon_t)d(c_t-\varepsilon_t) - \frac{\theta}{T}]$

Proposition 5-3: *If $f(\varepsilon_t)$ is a uniform distribution, the optimal capacity is an increasing function of σ_{c_t}.*

Proof: See Appendix.

This proposition's main implication is that the positive effect of the per MWh fuel cost's volatility on the optimal level of capacity investment[28] is maintained in the presence of demand uncertainty. Hence, in the remainder of our dissertation we make the simplifying assumption of no demand uncertainty[29]. In making this assumption, we are not saying that demand uncertainty does not exist. All we are saying is that demand uncertainty does not have a material effect on our main findings.

[28] Extensive simulations show that the nature of the effect of volatility on capacity investment, production and price does not change when both demand and fuel costs are uncertain.

[29] The solution of Tishler et al.'s (2008b) model, which includes demand uncertainty and non-random fuel price, is similar when the demand for electricity follows either normal or uniform distribution.

6. The effect of hedging on capacity investment

6.1 Introduction

In this chapter, we evaluate the effects of a possible use of call options to hedge the natural gas price risk. To this end, we add a hedge stage to the two-stage model presented in Chapter 5, between generation capacity planning and electricity production. While capacity planning remains Stage 1, electricity production becomes Stage 3. We denote the hedge stage as Stage 2, where the firms can buy call options to hedge[30] their fuel costs for part or all of their generation capacity.

6.2 The model

This three-stage model is solved backwards. We assume that preceding the third stage, the *i-th* firm built capacity, K_i, and purchased R_i fuel cost options at strike price *s*. If the maximal generation (= installed capacity) is hedged, then 100% of the fuel cost will be capped by the strike price. If only part of the generation capacity is hedged, the fuel cost of that part is capped, while the remainder is incurred at the spot natural gas price. Thus, the hedged fuel cost is:

$$[6.1] \qquad c_t^h = \begin{cases} c_t \text{ for any quantity of units of fuel,} & if\, c_t < s \\ s \text{ for the initial } R_i \text{ units; } c_t \text{ for all other } (Q_{it} - R_i) \text{ units,} & if\, c_t \geq s \end{cases}$$

The equilibrium generation is a straightforward extension of equation [5.8] in Chapter 5:

$$[6.2] \qquad Q_{it}^* = \begin{cases} K_i, \; if\; 0 \leq c_t < a - 2bK_i - bQ_{-it} \\ \frac{1}{2b}(a - c_t - bQ_{-it}), if\, a - 2bK_i - bQ_{-it} \leq c_t < a - 2bR_i - bQ_{-it} \\ R_i, \; if\, a - 2bR_i - bQ_{-it} \leq c_t < a \end{cases}$$

The equilibrium price is obtained by inserting equation [6.2] into equation [5.1]:

[30] Murphy and Smeers (2010) analyze a similar three-stage model. However, the second stage in their model focuses on a forward contract for electricity sale, while the second stage in our model is used for hedging the fuel cost.

[6.3] $$P_t^* = \begin{cases} a - bK_i - bQ_{-it}, & if 0 \le c_t < a - 2bK_i - bQ_{-it} \\ \frac{1}{2}(a - bQ_{-it} + c_t), & if a - 2bK_i - bQ_{-it} \le c_t < a - 2bR_i - bQ_{-it} \\ a - bR_i - bQ_{-it}, & if a - 2bR_i - bQ_{-it} \le c_t < a \end{cases}$$

If c_t is relatively low *(i.e.,* $c_t < a - 2bR_i - bQ_{-it}$*),* hedging does not alter the equilibrium quantity. The options' purchase alters the equilibrium quantity only when c_t is relatively high *(i.e.,* $c_t > a - 2bR_i - bQ_{-it}$ *).* When full capacity is hedged with $R_i = K_i$, the equilibrium generation equals $Q_{it}^* = K_i$ for any value of c_t. In this case, the price of electricity is capped at $P_t^* = a - 2bK_i - bQ_{-it}$. If only part of the capacity is hedged with $R_i < K_i$, the price of electricity will be capped at a higher level, so that $P_t^* = a - 2bR_i - bQ_{-it}$.

6.3 Stage 2 solution: The firm's optimal hedging strategy

In Stage 2, each firm sets the number of options to maximize the expected value of the profits, given the capacity constructed in Stage 1 and the distribution function *g(*c_t*)*. To ensure expositional simplicity, we begin by stating the *i-th* firm's optimization problem in Stage 2 for a particular value of the strike price. The proof of Proposition 6-2 in the Appendix shows that the results of this section hold true for any strike price value.

Suppose that $s = a - 2bK_i - bQ_{-it}$. The expected operating profit of firm *i* on day *t* in Stage 2 as a function of the number of options purchased is:

[6.4] $$E(\pi_{it}|R_i) = \int_0^{a-2bK_i-bQ_{-it}} g(c_t)K_i \cdot (a - bK_i - bQ_{-it} - c_t)\, dc_t + \int_{a-2bK_i-bQ_{-it}}^{a-2bR_i-bQ_{-it}} g(c_t)\left[\frac{1}{4b}(a - bQ_{-it} - c_t)^2 + R_i \cdot (c_t - a + 2bK_i + bQ_{-it})\right] dc_t + \int_{a-2bR_i-bQ_{-it}}^{a} g(c_t)R_i \cdot [(a - bR_i - bQ_{-it}) - (a - 2bK_i - bQ_{-it})]\, dc_t$$

The cost of buying a call option is $\int_s^a g(c_t) \cdot (c_t - s)dc_t$ (Lee et al., 2010). Thus, the *i-th* firm's optimization problem is:

[6.5] $$\max_{R_i}\left(\sum_{t=1}^{T} e^{-rt}\left[E[\pi_{it}|R_i] - R_i \cdot \int_{a-2bK_i-bQ_{-it}}^{a} g(c_t) \cdot (c_t - a + 2bK_i + bQ_{-it})dc_t\right]\right)$$

$$s.t. \quad R_i \leq K_i, R_i \geq 0$$

The first term in equation [6.5] depicts the expected profit given R_i options; the second term presents the cost of buying R_i options, leading to the following propositions:

Proposition 6-1: *Expected consumer surplus increases with the number of options purchased by the i-th firm.*

Proposition 6-2: *The optimal strategy of a profit-maximizing firm, for any strike price s, is not to hedge against natural gas price spikes.*

Proofs: See Appendix.

Proposition 6-1 states that consumers gain from fuel cost hedging, which leads to lower expected electricity prices and higher generation.

The intuition behind Proposition 6-2 is as follows: The reduction of profits due to a higher per MWh cost is divided between consumers and producers because part of this reduction is mitigated by an increase in the electricity price. However, the call option premium paid by an IPP for hedging against high natural gas prices accounts for all of the expected difference between the actual gas price and the strike price (for any gas price larger than the strike price). Therefore, the IPP's hedging cost exceeds the expected profit loss by not hedging. Hence, the optimal strategy of a profit-maximizing firm is not to hedge the natural gas fuel cost.

7. Investment in dual fuel plants under uncertainty

7.1 Introduction

This chapter provides an analytical framework to study the conditions under which producers and consumers can benefit from investing in dual fuel plants. As in Chapter 5, we develop a two-stage model to capture the lead-time in capacity construction, and short-term (daily or annual) fluctuating fuel costs, as in Gal et al. (2017). In the first stage of the model, only the probability distribution function of future daily (or annual) fuel costs is known. Profit-seeking IPPs maximize their expected profits by determining the amount of capacity to be constructed. In the second stage, once the daily fuel cost becomes known, each IPP selects its daily output up to the capacity built in the first stage via the Cournot model[31]. The daily output, in turn, determines the equilibrium market price.

Solved recursively, our two-stage model considers an oligopoly market with *N* identical IPPs (firms) operating daily over a period of *T* days. We first determine the equilibrium quantities, the equilibrium price and the profits in Stage 2. Then, we solve for each firm's optimal capacity to be built in Stage 1. We assume this capacity is built with dual fuel capability.

7.2 The model

The market's inverse demand function P_t on day $t = 1, \ldots, T$ is assumed to be linear:

[7.1] $$P_t = a - bQ_t,$$

where $a > 0$, $b > 0$, $Q_t = \sum_1^N Q_{it}$ is the total electricity generated by *N* firms on day *t*, and Q_{it}= the electricity generated by the *i-th* firm on day *t*.

The cost function of electricity generation of firm *i* on day *t* is given by:

[31] The assumption of Cournot competition is common in the electricity market reform literature (e.g., Wolfram, 1999; Borenstein et al., 2002; Murphy and Smeers, 2005; Tishler et al., 2008b).

[7.2] $$C(Q_{it}, \mathrm{K}_i) = \left(\frac{\Theta}{T} + \frac{\Psi}{T}\right) K_i + c_t^{min} Q_{it},$$

where Θ is the capacity cost (\$/MW-year) of natural gas capability, Ψ is the capacity cost of the dual-fuel capability, and $c_t^{min} \equiv min\{c_t, c^d\}$ is the per MWh fuel cost (\$/MWh), which is the lesser of the per MWh cost of natural gas c_t, and the per MWh cost of a dual fuel c^d, which is assumed to be non-stochastic and known with certainty. As *a* is the marginal willingness to pay (or outage cost) at $Q_t = 0$, $c_t < a$ and $c^d < a$.

The uncertainty of natural gas price implies the uncertainty of the per MWh cost of natural gas. Let c_0 = the initial per MWh cost of natural gas at the beginning of *t* = 1. Following Pilipovic (1997) and Geman (2005), we assume that $ln\left(\frac{c_t}{c_{t-1}}\right)$ is normally distributed with mean μ and variance $\sigma_{c_t}^2$. Thus, $\frac{c_t}{c_0}$ has a log-normal distribution[32], with parameters μt and $\sigma_{c_t}^2 t$:[33]

[7.3] $$ln\frac{c_t}{c_0} \sim N(\mu t, \sigma_{c_t}^2 t) \leftrightarrow \frac{c_t}{c_0} \sim lnN(\mu t, \sigma_{c_t}^2 t), \text{ and}$$

[7.4] $$\tilde{g}\left(\frac{c_t}{c_0} | \mu t, \sigma_{c_t}^2 t\right) = \frac{c_0}{c_t \sigma_{c_t} \sqrt{2\pi t}} e^{-\frac{1}{2}\frac{\left[ln\left(\frac{c_t}{c_0}\right) - \mu t\right]^2}{\sigma_{c_t}^2 t}}.$$

As in Chapter 5, we use σ_{c_t} as our measure of volatility of per MWh cost of natural gas in period *t* and, for expositional simplicity, denote $\tilde{g}\left(\frac{c_t}{c_0} | \mu t, \sigma_{c_t}^2 t\right) \equiv g(c_t)$.

7.3 Stage 2 solution: Equilibrium electricity generation and price

Assuming Cournot competition, the *N* firms set Q_{it} in the second stage to maximize their profits, π_{it}. Following Tishler et al. (2008) and Gal et al. (2017), the optimization problem of firm *i* on day *t* is:

[7.5] $$max_{Q_{it}} \pi_{it} = \left(P_t - c_t^{min}\right) \cdot Q_{it}$$

---

[32] See section 3.5 for a detailed analysis of the log-normal distribution in the natural gas market.

[33] Assuming a risk-neutral investment implies $\mu t = rt - \frac{\sigma_{c_t}^2 t}{2}$, where *r* is the riskless interest rate (see Lee et al., 2010 on this issue).

s.t. $Q_{it} \leq K_i$

The properties of the equilibrium solution in the second stage are summarized in Proposition 7-1 below.

Proposition 7-1:

Let $c_{K_i} \equiv a - 2bK_i - bQ_{-it}$. Then, the equilibrium quantity and equilibrium price at Stage 2 are given by one of the following two cases:

Case A. *When $c_{K_i} \leq c^d$,*

[7.6] $$Q_{it}^* = \begin{cases} K_i, & if\ 0 \leq c_t < c_{K_i} \\ \frac{1}{2b}(a - c_t - bQ_{-it}), & if\ c_{K_i} \leq c_t < c^d \\ \frac{1}{2b}(a - c^d - bQ_{-it}), & if\ c^d \leq c_t < \infty \end{cases}$$

[7.7] $$P_t^* = \begin{cases} a - bK_i - bQ_{-it}, & if\ 0 \leq c_t < c_{K_i} \\ \frac{1}{2}(a + c_t - bQ_{-it}), & if\ c_{K_i} \leq c_t < c^d, \\ \frac{1}{2}(a + c^d - bQ_{-it}), & if\ c^d \leq c_t < \infty \end{cases}$$

where $Q_{-it} \equiv \sum_{j \neq i} Q_{jt}$.

Case B. *When $c_{K_i} > c^d$, $Q_{it}^* = K_i$ and $P_t^* = a - bK_i - bQ_{-it}$ for any value of c_t.*

Proof: See Appendix.

Note that c_{K_i} is the largest value of the per MWh fuel cost for which the firm would utilize the marginal capacity unit to generate full capacity. When $c_{K_i} > c^d$ (i.e., the per MWh dual-fuel cost is relatively low), the per MWh fuel cost c_t^{min} is smaller than c_{K_i} for any realization of the per MWh cost of natural gas c_t. Therefore, the firm would generate full capacity K_i for any value of c_t. When $c_{K_i} \leq c^d$ (i.e., the per MWh dual-fuel cost is relatively high), the firm would generate full capacity only if $c_t \leq c_{K_i}$; otherwise, it would produce less than full capacity.

7.4 Stage 1 solution: Optimal capacity

Following Tishler et al. (2008) and Gal et al. (2017), the optimization problem of firm *i* at stage 1 is:

[7.8] $$max_{K_i} \sum_{t=1}^{T} e^{-rt}\left(E[\pi_{it}] - \frac{\theta+\Psi}{T} \cdot K_i\right).$$

The expected operating profits of firm *i* on day *t* are:

[7.9] $$E[\pi_{it}] = \int_0^{c_{K_i}}[a - bK_i - bQ_{-it} - c_t]K_i g(c_t)dc_t + \int_{c_{K_i}}^{c^d}\frac{1}{4b}[a-c_t-bQ_{-it}]^2 g(c_t)dc_t + \int_{c^d}^{\infty}\frac{1}{4b}[a-c^d-bQ_{-it}]^2 g(c_t)dc_t$$ for case A of Proposition 7-1, and

[7.10] $$E[\pi_{it}] = \int_0^{c^d}[a - bK_i - bQ_{-it} - c_t]K_i g(c_t)dc_t + \int_{c^d}^{\infty}[a - bK_i - bQ_{-it} - c^d]K_i g(c_t)dc_t$$ for case B of Proposition 7-1.

The properties of the equilibrium solution in the first stage are summarized in Proposition 7-2 below.

<u>Proposition 7-2:</u>

The optimal capacity, K^*, is given by one of the following two cases (corresponding to the two cases of Proposition 1):

<u>Case A.</u> When $c_{K^*} \leq c^d \Leftrightarrow \sum_{t=1}^{T} e^{-rt} \cdot \left[\int_0^{c^d}(c^d - c_t)\, g(c_t)dc_t - \frac{\Theta+\Psi}{T}\right] \geq 0;$ *the optimal capacity is given in an implicit form*

[7.11] $$\sum_{t=1}^{T} e^{-rt} \cdot \left[\int_0^{c_{K^*}}(c_{K^*} - c_t) \cdot g(c_t)dc_t - \frac{\Theta+\Psi}{T}\right] = 0,$$

where $c_{K^*} \equiv a - b(N+1)K^*$.

<u>Case B.</u> When $c_{K^*} > c^d \Leftrightarrow \sum_{t=1}^{T} e^{-rt} \cdot \left[\int_0^{c^d}(c^d - c_t)\, g(c_t)dc_t - \frac{\Theta+\Psi}{T}\right]$ *<0; the optimal capacity is given in an explicit form*

[7.12] $$K^* = \frac{a-c^d}{b(N+1)} + \frac{\sum_{t=1}^{T} e^{-rt} \cdot \left[\int_0^{c^d}(c^d-c_t)g(c_t)dc_t - \frac{\Theta+\Psi}{T}\right]}{b(N+1)\cdot\sum_{t=1}^{T} e^{-rt}}.$$

Proof: See Appendix.

The value $\sum_{t=1}^{T} e^{-rt} \cdot \left[\int_0^{c^d} (c^d - c_t)\, g(c_t) dc_t - \frac{\Theta+\Psi}{T}\right]$ depicts the expected net saving of using natural gas at c_t, instead of using the dual fuel, whenever $c_t < c^d$. The expected saving increases with the volatility of $c_t$and the dual fuel cost c^d.

Proposition 7-2 implies that when the expected net saving of using natural gas is high, the optimal capacity is likely smaller, chiefly because the capacity cost is larger for attaining the dual fuel capability. Alternatively, when the expected saving of using natural gas is small, then optimal capacity in a dual fuel market would be larger, compared to a single fuel market.

Proposition 7-3 summarizes the effect of fuel cost volatility of σ_{c_t}on the equilibrium solution.

Proposition 7-3: *An increase in σ_{c_t} causes:*

- ***(i)*** *An increase in the optimal capacity.*
- ***(ii)*** *An increase in the expected operating profits in the optimal solution on day t.*
- ***(iii)*** *An increase in the expected consumer surplus in the optimal solution on day t.*
- ***(iv)*** *A decline in the expected electricity price in the optimal solution on day t.*

Proof: See Appendix.

A lognormal distribution implies that the probability of low c_t rises when σ_{c_t} increases. Similar to a single fuel case of Gal et al. (2017), higher fuel cost volatility induces dual plants to increase their installed capacity, so as to improve their chances of benefiting from low natural gas prices. The resulting higher installed capacity leads to lower electricity prices and higher consumer surplus.

Finally, the effect of an increase in c^d on the model's equilibrium is summarized by Proposition 7-4 below.

Proposition 7-4: *An increase in c^d causes:*

- ***i.*** *No change in the optimal capacity in case A; and a decline in the optimal capacity in case B.*

ii. *A decline in the expected operating profits in the optimal solution on day t.*

iii. *A decline in the expected consumer surplus in the optimal solution on day t.*

iv. *An increase in the expected electricity price in the optimal solution on day t.*

Proof: See Appendix that also defines cases A and B.

To understand the intuition underlying the above proposition, consider an increase of c^d that decreases the value of switching fuels. In case A, c^d is already high, and the optimal capacity is set as in a single fuel market. Therefore, in this case, an additional increase of c^d does not affect optimal capacity. In case B, however, c^d is initially low and the initial probability of using dual capability is higher. As a result, an increase of c^d decreases the probability of using the dual fuel, leading to a smaller optimal capacity. As the probability of switching fuel decreases, the exposure to higher fuel costs increases, leading to higher expected electricity price increases, higher expected operating profits, and lower expected consumer surplus.

In summary, this chapter provides an analytical tool for estimating the costs and benefits of dual fuel capability. Our main finding is that the value of dual fuel capability declines when the volatility of the price of natural gas is high, because a higher volatility implies a higher probability of low natural gas prices under the log-normal distribution, thus reducing the value of the dual fuel capability.

8. Optimal capacities in a two-technology market

We have thus far only considered a single-generation technology based on internal combustion, as exemplified by natural gas-fired generation. While the generation units may have a dual fuel capability, they all use the same technology. The reality is that generation units can have different technologies. A good case in point is internal combustion used by gas-fired units and steam generation used by coal-fired units. This chapter examines whether capacity mix can support IPPs' risk management strategy by allowing them to increase coal generation whenever the per MWh fuel cost of burning natural gas exceeds that of burning coal.

8.1 The model

The model assumes an oligopolistic market with N identical power producers, each of which can invest in two technologies, which differ according to their per MWh fuel costs and investment costs, i.e., gas and coal. More specifically, we assume that the per MWh gas generation cost of natural gas is a random variable, following lognormal distribution $g(c_t)$, while the per MWh of coal generation cost is a constant, c^C. Hence, the realization of c_t can be higher or lower than c^C.

Following Milstein and Tishler (2012) and Gal et al. (2017), the market equilibrium price and capacity come from a two-stage model. In the first stage, each firm decides how much generation capacity to build using each technology, given the annual construction costs Θ^G and Θ^C, the coal price c^c, and the distribution function of the gas price, $g(c_t)$. In the second stage, the natural gas fuel cost price c_t is known, and the firms decide how much electricity to generate employing both technologies. The generation at time t in Stage 2 is limited by the capacities constructed in Stage 1 for each technology.

The model is solved backwards. First, we determine the equilibrium quantity, the equilibrium price and the profit for each technology in Stage 2. Then, we determine the optimal gas capacity, K_i^G(MW) and coal capacity, K_i^C(MW) to be built in Stage 1. The second stage of the game can be repeated *T* independent times.

As before, the market's inverse demand function P_t on day $t = 1, \ldots, T$ is assumed to be linear:

[8.1] $$P_t = a - bQ_t,$$

where $a > 0$, $b > 0$, $Q_t = \sum_{i=1}^{N}\left(Q_{it}^G + Q_{it}^C\right)$ is the total electricity generated by *N* firms, Q_{it}^G is the electricity generated by firm *i* on day *t* using gas plants, and Q_{it}^C is the electricity generated by firm *i* on day *t* using coal plants.

For simplicity, variable costs other than those related to fuel are assumed to be zero[34]. Following Newbery (1998), Besanko and Dorazelski (2004), Murphy and Smeers (2005), Tishler et al. (2008), and Gal et al. (2017), we assume a linear amortization of the debt service, and thus the cost function of electricity generation of firm *i* on day *t* employing the gas technology (the coal technology) and a generator of K_i^G (K_i^C) MW of capacity is:

[8.2] $$C\left(Q_{it}^G, K_i^G\right) = \frac{\Theta^G}{T} K_i^G + c_t Q_{it}^G,$$

[8.3] $$C\left(Q_{it}^C, K_i^C\right) = \frac{\Theta^C}{T} K_i^C + c^C Q_{it}^C,$$

where Θ^G (Θ^C) = marginal gas (coal) capacity cost (\$/MW-year) applicable to the *i*-th firm's capacity K_i^G (K_i^C), c_t= per MWh gas generation cost (\$/MWh) = generation heat rate (MMBtu/MWh) × natural gas price (\$/MMBtu), and c^C = per MWh coal generation cost.[35] We assume that $\Theta^G < \Theta^C$ and $c^C < a$.

[34] The assumption of zero non-fuel cost is later relaxed in our empirical illustration in Section 6.

[35] The decision about capacity and, hence, capacity total cost, is incurred in Stage 1. There are several ways to formulate capacity costs in our model. In reality, the choice of the financing period and the stream of debt payments for the capacity are usually related to the investment's lifetime. We chose to assume a linear amortization of the debt over the project's lifetime.

8.2 Stage 2 solution: Equilibrium electricity generation quantity and price

The objective of the *i*-th firm in Stage 2 is to maximize its operating profits, π_{it}, conditional on K_i^G and K_i^C $(i = 1, \dots, N)$, Q_{jt}^G and Q_{jt}^C $(j = 1, \dots, N; j \neq i)$.

[8.4] $$\max_{Q_{it}^G, Q_{it}^C} \pi_{it} = (P_t - c_t) \cdot Q_{it}^G + (P_t - c^C) \cdot Q_{it}^C$$

s.t. $$Q_{it}^G \leq K_i^G, Q_{it}^C \leq K_i^C, Q_{it}^G \geq 0, Q_{it}^C \geq 0$$

The Karush–Kuhn–Tucker (KKT) conditions are:

[8.5] $$a - 2bQ_{it}^G - bQ_{-it}^G - 2bQ_{it}^C - bQ_{-it}^C - c_t - \lambda^G + \mu^G = 0,$$

$$a - 2bQ_{it}^G - bQ_{-it}^G - 2bQ_{it}^C - bQ_{-it}^C - c^C - \lambda^C + \mu^C = 0,$$

$$\mu^G \cdot Q_{it}^G = 0, \mu^C \cdot Q_{it}^C = 0, \lambda^G \cdot \left(K_i^G - Q_{it}^G\right) = 0, \lambda^C \cdot \left(K_i^C - Q_{it}^C\right) = 0,$$

$$K_i^G - Q_{it}^G \geq 0, K_i^C - Q_{it}^C \geq 0, K_i^G \geq 0, K_i^C \geq 0, \lambda^G \geq 0, \lambda^C \geq 0, \mu^G \geq 0,$$

$$\mu^C \geq 0,$$

where $Q_{-it}^G \equiv \sum_{j \neq i} Q_{jt}^G$, $Q_{-it}^C \equiv \sum_{j \neq i} Q_{jt}^C$, λ^G and λ^C are the dual variables of the capacity constraints, and μ^G and μ^C are the dual variables for non-negativity.

For given values of demand and costs, the optimal quantities equal capacities, i.e., $Q_{it}^{G*} = K_i^G$ and $Q_{it}^{C*} = K_i^C$, assuming that both capacities that have been built before the second stage are relatively small because the investment costs are relatively high in the first stage (Maskin and Tirole, 1988). However, when c_t exceeds a certain value, an IPP is forced to lower the output below K_i^G to compensate for higher generation costs. Thus, production employing coal is at full capacity K_i^C for any given c^c and c_t. In contrast, natural gas-fired generation's output depends on the value of c_t and varies from zero to full capacity K_i^G. Therefore, the equilibrium solution in the second stage, which satisfies [8.4], is:

[8.6] $$\left(Q_{it}^{G*}, Q_{it}^{C*}\right) =$$

$$\begin{cases} \left(K_i^G, K_i^C\right), & if\, 0 \leq c_t < c_{K_i^G + K_i^C} \\ \left(\frac{1}{2b}\left[a - c_t - bQ_{-it}^G - bQ_{-it}^C\right] - K_i^C, K_i^C\right), & if\, c_{K_i^G + K_i^C} \leq c_t < c_{K_i^C} \\ \left(0, K_i^C\right), & if\, c_{K_i^C} \leq c_t < \infty \end{cases}$$

where $c_{K_i^C} \equiv a - 2bK_i^C - bQ_{-it}^G - bQ_{-it}^C$, $c_{K_i^G} \equiv a - 2bK_i^G - bQ_{-it}^G - bQ_{-it}^C$, and $c_{K_i^G+K_i^C} \equiv a - 2bK_i^G - 2bK_i^C - bQ_{-it}^G - bQ_{-it}^C$.

Equation [8.6] states that only one scenario is possible in the second stage of the game, if a firm has decided to build the capacities of both technologies in the first stage. That is, if the per MWh gas generation cost c_t is low on day t, a firm produces at full capacity, employing gas and coal. If the per MWh gas cost c_t is relatively high (i.e., $c_t > c_{K_i^G+K_i^C}$) on day t, a firm decreases the use of gas, and production employing gas is at less than full capacity. When c_t is very high, a firm generates electricity employing only coal.

8.3 Stage 1 solution: Optimal capacities

In a market with two technologies, in Stage 1 the firm sets the capacities mix to maximize the sum of the expected daily profits over the operation period *T*, given the gas cost distribution $g(c_t)$:

[8.7] $$\max_{K_i^G, K_i^C} \sum_{t=1}^{T} e^{-rt} \left[E\left(\pi_{it} \middle| K_i^G, K_i^C\right) - \frac{\Theta^G}{T} K_i^G - \frac{\Theta^C}{T} K_i^C \right],$$

where expectations are taken over c_t $(t = 1, \dots, T)$.

The expected variable profit of the *i*-th firm on day *t* is:

[8.8] $$E\left(\pi_{it} \middle| K_i^G, K_i^C\right) = \int_0^{\infty} \left[(P_t - c_t) Q_{it}^G + (P_t - \mathrm{c}^{\mathrm{C}}) Q_{it}^C \right] g(c_t) dc_t.$$

Inserting [15] into [17], the optimization problem of firm *i* in Stage 1 is

[8.9] $$\max_{K_i^G, K_i^C} \sum_{t=1}^{T} e^{-rt} \left[\int_0^{c_{K_i^G+K_i^C}} \left(a - bK_i^G - bQ_{-it}^G - bK_i^C - bQ_{-it}^C - c_t\right) \cdot K_i^G g(c_t) dc_t + \int_0^{c_{K_i^G+K_i^C}} \left(a - bK_i^G - bQ_{-it}^G - bK_i^C - bQ_{-it}^C - c^C\right) \cdot K_i^C g(c_t) dc_t + \int_{c_{K_i^G+K_i^C}}^{c_{K_i^C}} \frac{1}{4b} \left(a - c_t - bQ_{-it}^G - bQ_{-it}^C\right)^2 g(c_t) dc_t + \int_{c_{K_i^G+K_i^C}}^{c_{K_i^C}} (c_t - c^C) K_i^C g(c_t) dc_t + \int_{c_{K_i^C}}^{\infty} \left(a - bK_i^C - bQ_{-it}^G - bQ_{-it}^C - c^C\right) \cdot K_i^C g(c_t) dc_t - \frac{\Theta^G}{T} K_i^G - \frac{\Theta^C}{T} K_i^C \right]$$

s.t. $K_i^G \geq 0, K_i^C \geq 0$

Assuming the symmetric solution (i.e. $K_1^G = \cdots = K_N^G = K^G$ and $K_1^C = \cdots = K_N^C = K^C$), the Karush–Kuhn–Tucker (KKT) conditions are:

[8.10] $\sum_{t=1}^{T} e^{-rt} \cdot \int_0^{c_{K^G+K^C}} \left[c_{K^G+K^C} - c_t\right] \cdot g(c_t)dc_t - \frac{e^{-r}(1-e^{-rT})}{1-e^{-r}} \cdot \frac{\Theta^G}{T} + \mu_1 = 0,$

$\sum_{t=1}^{T} e^{-rt} \cdot \left[\int_0^{c_{K^G+K^C}} \left[c_{K^G+K^C} - c^C\right] g(c_t)dc_t + \int_{c_{K^G+K^C}}^{c_{K^C}} (c_t - c^C) g(c_t)dc_t + \int_{c_{K^C}}^{\infty} \left[c_{K^C} - c^C\right] g(c_t)dc_t\right] - \frac{e^{-r}(1-e^{-rT})}{1-e^{-r}} \cdot \frac{\Theta^C}{T} + \mu_2 = 0,$

$\mu_1 \cdot K^G = 0, \mu_2 \cdot K^C = 0, K^G \geq 0, K^C \geq 0, \quad \mu_1 \geq 0, \mu_2 \geq 0$

Where μ_1 and μ_2 are the dual variables for non-negativity; $c_{K^G+K^C} = a - b(N+1)(K^G + K^C)$; $c_{K^C} = a - b(N+1)K^C$;

The properties of the first-stage equilibrium solution are summarized in Proposition 8-1 below.

Proposition 8-1 *There exists a unique equilibrium solution in the first stage of the game. This solution is given by one of the following three scenarios:*

Scenario (i). When $\sum_{t=1}^{T} e^{-rt} \cdot \int_0^{c^C+\Theta^C/T} \left[c^C + \Theta^C/T - c_t\right] g(c_t)dc_t \leq \frac{e^{-r}(1-e^{-rT})}{1-e^{-r}} \cdot \frac{\Theta^G}{T}$,

[8.11] $K^{G*} = 0$, and $K^{C*} = \frac{a - c^C - \frac{\Theta^C}{T}}{b(N+1)}$.

Scenario (ii). When $\sum_{t=1}^{T} e^{-rt} \cdot \int_0^{c^C+\Theta^C/T} \left[c^C + \Theta^C/T - c_t\right] g(c_t)dc_t > \frac{e^{-r}(1-e^{-rT})}{1-e^{-r}} \cdot \frac{\Theta^G}{T}$ and $c^C + \frac{\Theta^C}{T} < c_0 \cdot T / \frac{e^{-r}(1-e^{-rT})}{1-e^{-r}} + \frac{\Theta^G}{T}$, the optimal solution is given in an implicit form:

[8.12] $\sum_{t=1}^{T} e^{-rt} \cdot \int_0^{a-b(N+1)(K^{G*}+K^{C*})} \left[a - b(N+1)(K^{G*} + K^{C*}) - c_t\right] g(c_t)dc_t = \frac{e^{-r}(1-e^{-rT})}{1-e^{-r}} \cdot \frac{\Theta^G}{T}$, *and*

[8.13] $\sum_{t=1}^{T} e^{-rt} \cdot \int_{a-b(N+1)K^{C*}}^{\infty} \left[c_t - a + b(N+1)K^{C*}\right] g(c_t)dc_t = \sum_{t=1}^{T} e^{-rt} \cdot \int_0^{\infty} (c_t - c^C)\, g(c_t)dc_t - \frac{e^{-r}(1-e^{-rT})}{1-e^{-r}} \cdot \frac{\Theta^C - \Theta^G}{T}.$

Scenario (iii). When $c^C + \frac{\Theta^C}{T} \geq c_0 \cdot T / \frac{e^{-r}(1-e^{-rT})}{1-e^{-r}} + \frac{\Theta^G}{T}$, $K^{C*} = 0$ and the optimal solution of K^{G*} is given in an implicit form:

[8.14] $\sum_{t=1}^{T} e^{-rt} \cdot \int_0^{a-b(N+1)K^{G*}} [a - b(N+1)K^{G*} - c_t]\, g(c_t) dc_t = \frac{e^{-r}(1-e^{-rT})}{1-e^{-r}} \cdot \frac{\Theta^G}{T}.$

Proof: See Appendix.

Proposition 8-1 implies that only one of three scenarios is possible for any given value of the variable and capacity costs of technology **C**. When these costs are low relative to the expected variable and capacity costs of technology **G** (scenario (i)), IPPs will build only coal capacity. When the costs of both technologies are comparable with each other (scenario (ii)), it is worth for IPPs to build a capacity mix. However, when the variable and capacity costs of technology **C** are high relative to the expected costs of technology **G** (scenario (iii)), the firms will build only gas capacity.

Proposition 8-2

In scenario ii, the size of the natural gas capacity in the technology mix increases along with the volatility of the natural gas price.

Proof: See Appendix.

As volatility increases, the probability of natural gas generation cost falling below coal generation cost increases. Therefore, the firm's optimal strategy is to increase the gas capacity share in the technology mix, to benefit from the probability of lower fuel costs.

9. Real world examples

9.1 California and Texas electricity markets

To clarify our analytical results, this chapter presents numerical analyses of two simplified[36] competitive markets. We start by using stylized data from California's market to illustrate the basic model of discussed in Chapters 5 and 6. We then employ stylized data from Texas's electricity market to elucidate the dual fuel capacity model discussed in Chapter 7 and the technology mix model from Chapter 8. We start with a brief description of the data that we used to characterize the California and Texas markets.

California electricity market. In 1998, California established a competitive wholesale market and an independent system operator (CAISO). The market was vulnerable to abuse by dominant suppliers, leading to the energy crisis of blackouts and shortages in 2001-2002 (Bushnell, 2004). Following the crisis, new market rules were adopted, and today the market is considered competitive and well-functioning. Operating the day-ahead, real-time and ancillary services markets, the CAISO centrally dispatches participating generators under open transmission access to reliably meet the state's nodal demands (California ISO[37], 2013).

In 2015, natural gas-fired generation accounted for 56% of California's total electricity supply, with the remainder coming from hydro, nuclear, and renewable resources[38]. The average hourly consumption during 2015 was 29,800 MWh (EIA, 2017) at an average electricity price of \$150.3/MWh (EIA, 2017). Following Milstein and Tishler (2015), we assume that the price elasticity of demand is -0.25, implying that the inverse demand function in California is $P_t = 750 - 0.0201Q_t$.

[36] Because of its simplicity, our model does not portray how the California and Texas electricity markets work. Rather, this section uses the California and Texas data for the sole purpose of numerically demonstrating how fuel cost volatility variations may affect prices, quantities, profits and consumer surplus.

[37] https://www.caiso.com/market/Pages/MarketProcesses.aspx

[38] California Energy Commission, Energy Almanac – Electric Generation Capacity & Energy: http://energyalmanac.ca.gov/electricity/electric_generation_capacity.html.

Texas Market. Electricity deregulation in Texas was approved in 2002 and as of today consumers can freely choose their power supplier. Competition in Texas is considered robust, with many competitors and products (Harvey, 2015).

With net summer capacity of 117,144 MW, the primary generation fuels in Texas in 2015 were natural gas (53%) and coal (27%) (EIA Data Browser). The average hourly electricity consumption in 2015 was 44,787 MWh at an average retail price of $87/MWh (EIA Data browser). Assuming price elasticity of demand equals -0.25, as in California, the inverse demand function for Texas in 2015 is given by: $\boldsymbol{P_t}$ = 435-0.0077$\boldsymbol{Q_t}$.

EU Electricity market indicators report (2017)[39] indicates that the number of main electricity companies participating in most European electricity markets is usually 5 or less. Therefore, all the examples in chapter assume 5 symmetric firms in the market.

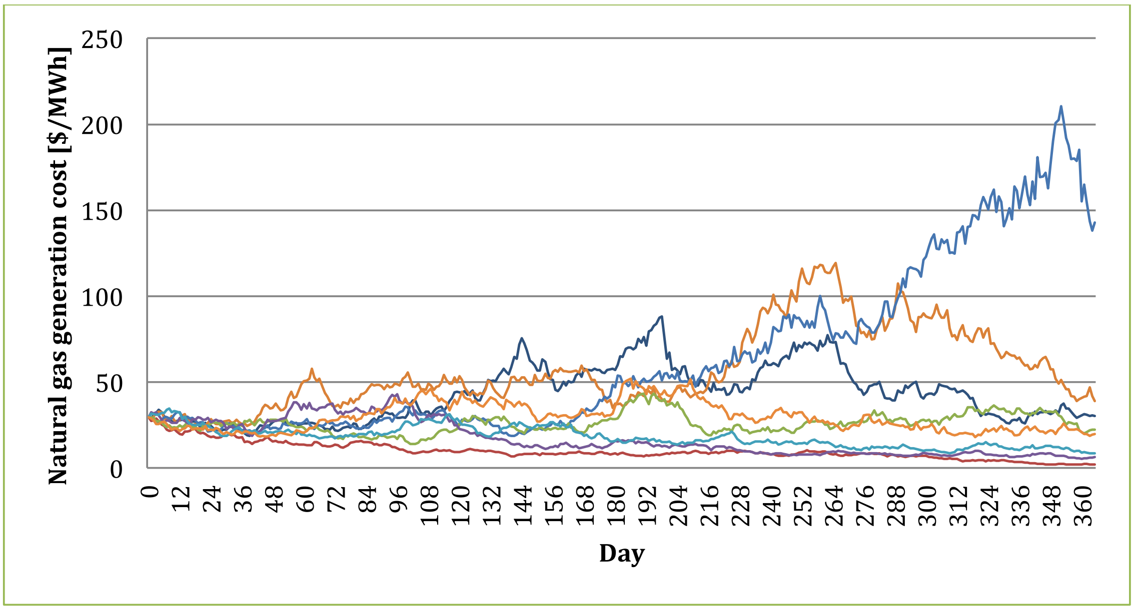
Natural gas generation cost. Following Section 3.5, we assume that the price of natural gas follows a lognormal distribution. The initial per MWh natural gas generation cost in both markets in 2015 was $c_0 =$ \$29.5/MWh, based on the CCGT's heat rate of 7.88 MMBTU/MWh, an average Henry Hub natural gas price of \$3.3/MMBTU (EIA Data browser) and a variable cost of \$3.5/MWh (EIA 2015, Table 1).

Figure 9-1 contains 10 price scenarios[40] for 100% annualized volatility. The average price evolution follows the interest rate (4% annually). Most of the scenarios lead to a price close to the average, but in some scenarios, the price can increase, over a 365-days' period, to 10 times the initial price.

[39] http://ec.europa.eu/eurostat/statistics-explained/index.php/Electricity_market_indicators.

[40] Each scenario begins with the same natural gas generation cost on day 1. The change in the cost from day *t* to day *t+1* is generated according to a lognormal distribution.

Figure 9-1: Simulations of natural gas generation cost evolution over 1 year

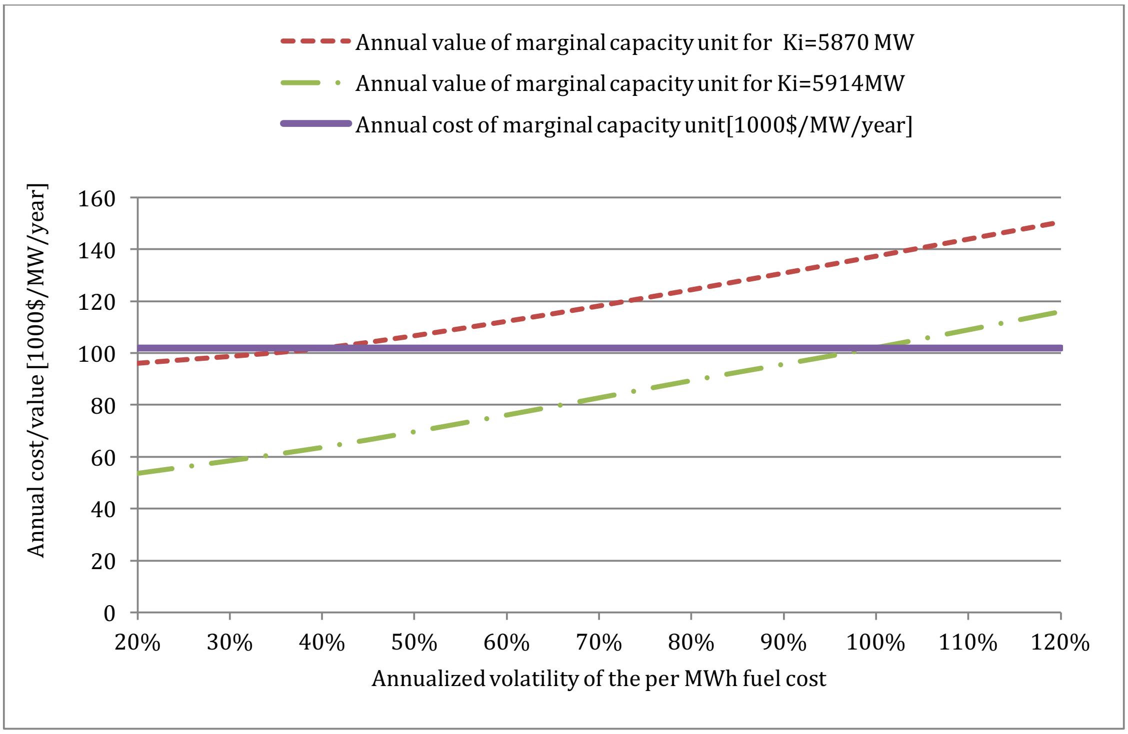


9.2 Real world example of Chapter 5: Capacity investment with uncertain fuel cost

We used the California data to illustrate the optimal capacity model discussed in Chapter 5. We assume that the capacity cost is $\theta/T =$ \$285.12/MW-day, based on a \$1023/kW total installed cost, a 6% WACC, a 20-year depreciation schedule, and an average annual fixed cost of \$15.37/kW/year (EIA 2013, Table 1).

Figure 9-2 depicts the annual profit of the marginal capacity units, as a function of the fuel cost volatility, for an electricity market with five identical firms, over 365 days. It shows that the marginal profit increases with volatility. Thus, a firm's optimal capacity increases with per MWh fuel cost volatility. The optimal per producer capacity for an annualized volatility of 40% is 5870 MW, less than the 5914 MW for an annualized volatility of 100%. This finding's importance is not so much about the small increase in a firm's optimal capacity, but rather the absence of a capacity decrease in response to rising fuel cost volatility.

Figure 9-2: Value and cost of marginal capacity unit as a function of the annualized volatility (*N*=5)



Based on the equilibrium solution depicted in Chapter 5 (equation (5.13)), figure 9-3 presents the optimal generation capacity for different numbers of firms in the market as a function of the annualized volatility of the per MWh fuel cost. As expected, higher volatility implies higher optimal capacity and an increase in the number of firms in the market increases the market's total capacity. Moreover, an increase in volatility from 20% to 120% increases the optimal generation capacity by about the same ~ 1% for N = 3, 5, 10, 20.

Figure 9-3: Optimal market capacity

as a function of the annualized volatility and the number of firms

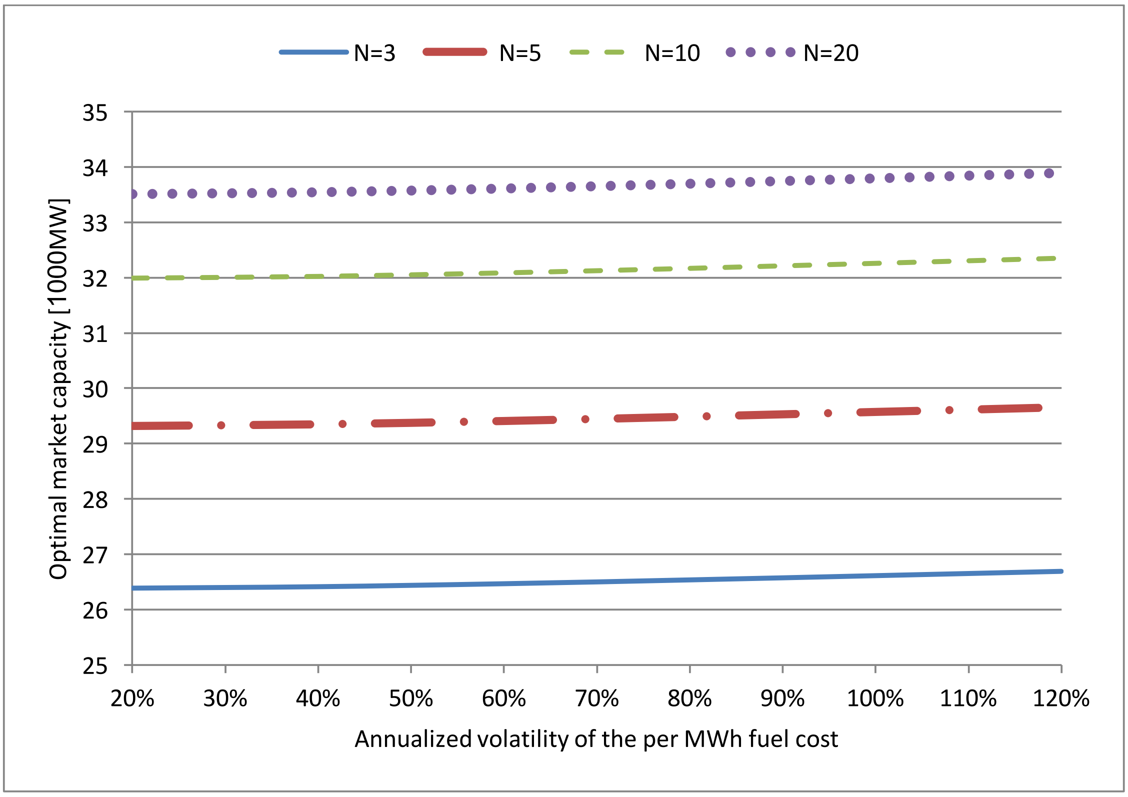
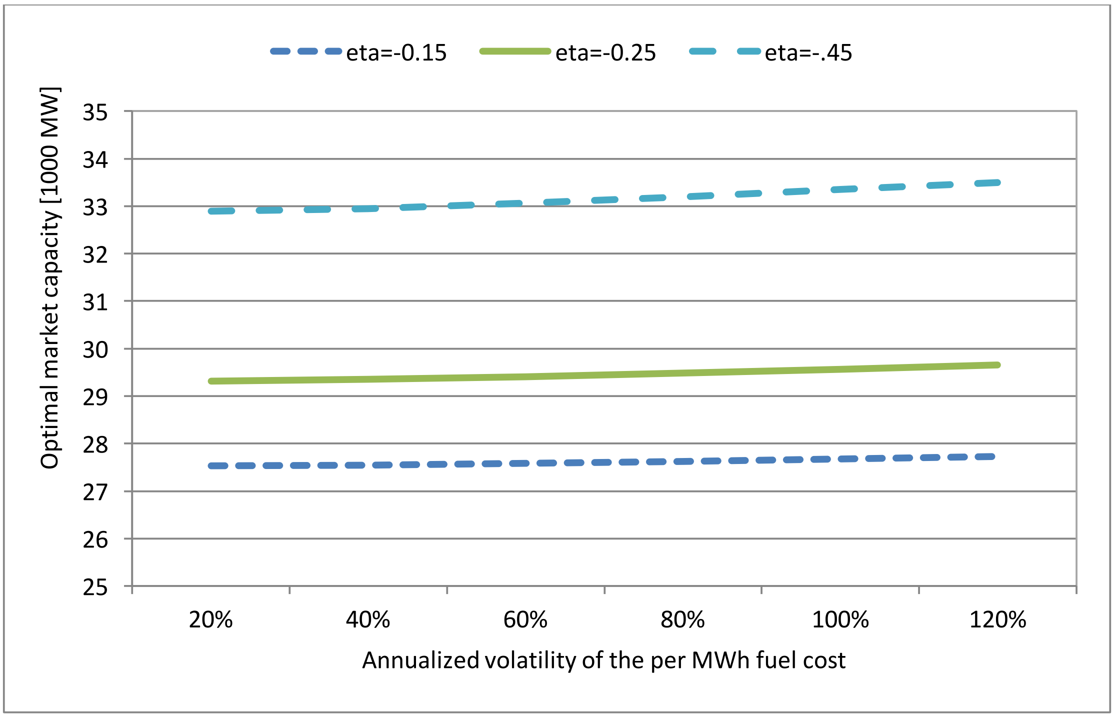


Figure 9-4 shows the sensitivity of the optimal capacity to changes in the demand price elasticity for the range -.15 to -.45. As predicted by Proposition 5.3, larger demand price responsiveness implies higher optimal capacity. This is because an increase in the price elasticity's size implies larger demand responses, which cause more price fluctuations that lead to higher expected profit. to smaller per MWh cost changes; therefore, the expected revenues, given a constant fuel cost volatility level, increases.

Figure 9-4: Sensitivity of optimal capacity to demand elasticity (N=5)



Using the solution for equilibrium quantity presented in Chapter 5 (equation (5.8)) and volatility values of 80%, 100% and 120%, we compute the distributions of equilibrium generation and equilibrium electricity prices in California, as a function of natural gas volatility (Figure 9-5), showing that higher volatility implies more installed capacity, which tends to increase equilibrium quantities. The large bold dots in the graph show the concentration of the probability at a point representing equilibrium generation equal to full capacity for each annualized volatility level. This concentration of the probability occurs at the range of generation costs, $0 < c_t < c_{ki}$.

Figure 9-5: Distribution function of equilibrium generation (N=5)

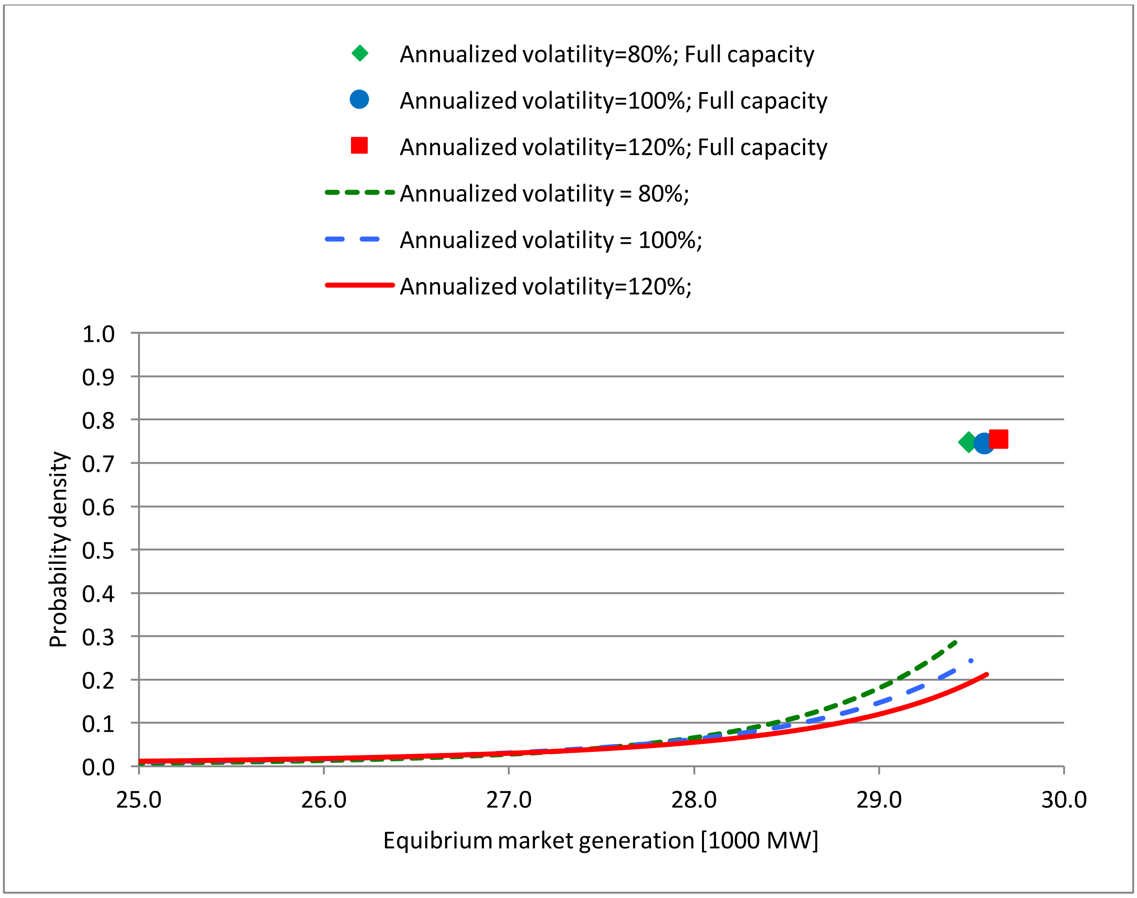


Figure 9-6 presents the distributions of the equilibrium electricity prices. As expected, higher capacity investment, due to higher volatility, reduces the minimal and average price, as proved by proposition 5-2(b). The probability of price spikes[41], however, is higher since the higher per MWh fuel cost volatility "flattens" the log normal distribution, leading to a higher probability that production will be at a very high natural gas price, in addition to a larger mass at very low prices. As in figure 9-5, we get a concentration of the

[41] Note that price spikes occur when per MWh fuel cost (which is a result of high natural gas price) is high and, therefore, the profit-maximizing IPP prefers to produce at less than full capacity. Furthermore, the higher the natural gas price is, the more significant is the electricity price spike will be.

probability at a price representing generation at full capacity. This equilibrium price occurs at the range of generation costs, $0 < c_t < c_{ki}$.

Figure 9-6: Distribution function of equilibrium electricity price (*N*=5)

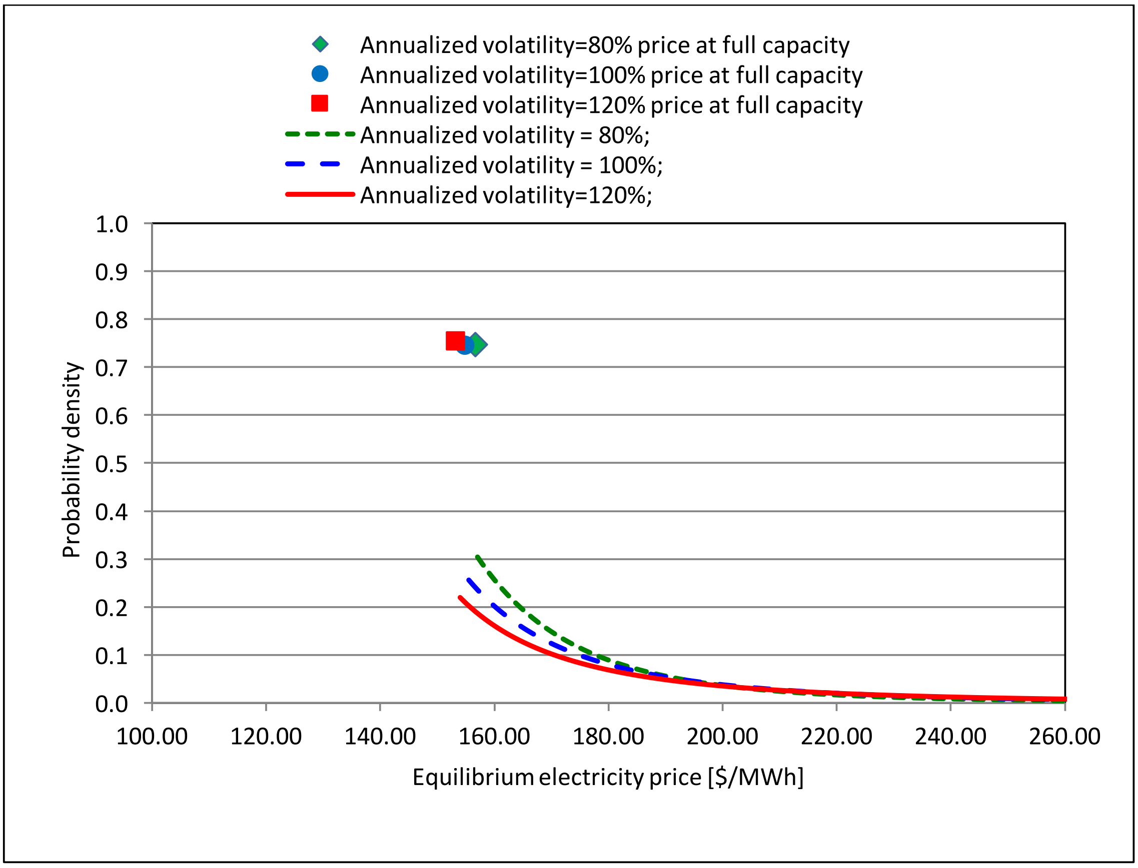
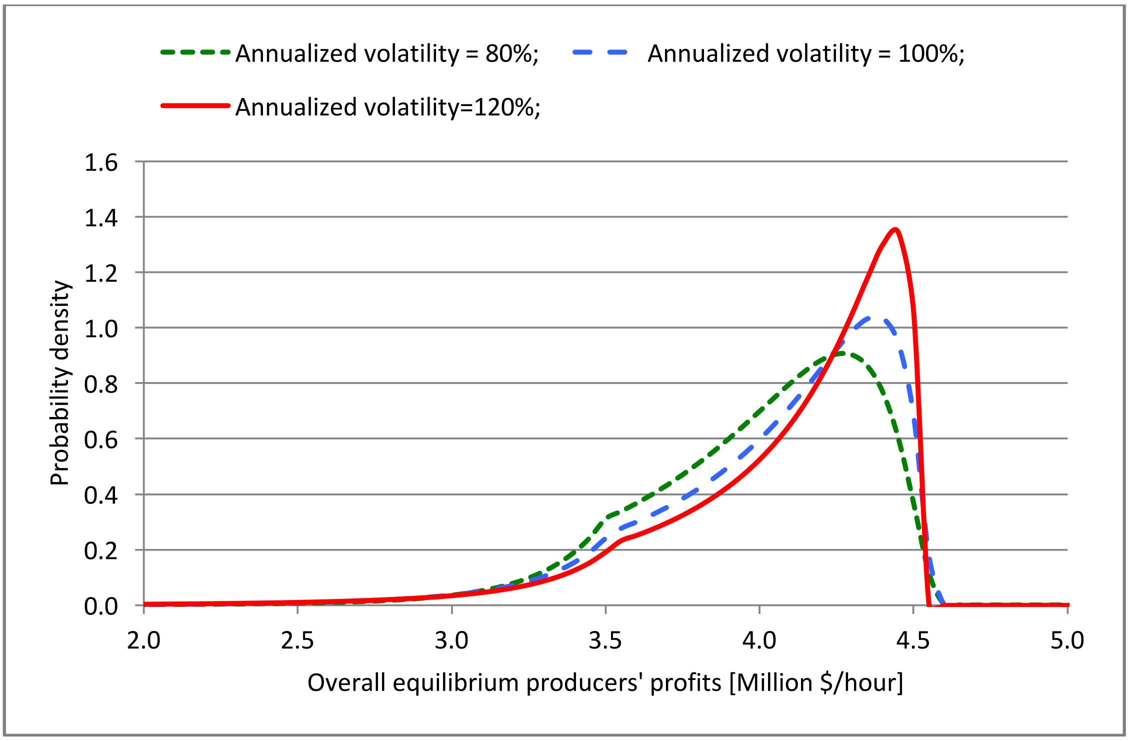


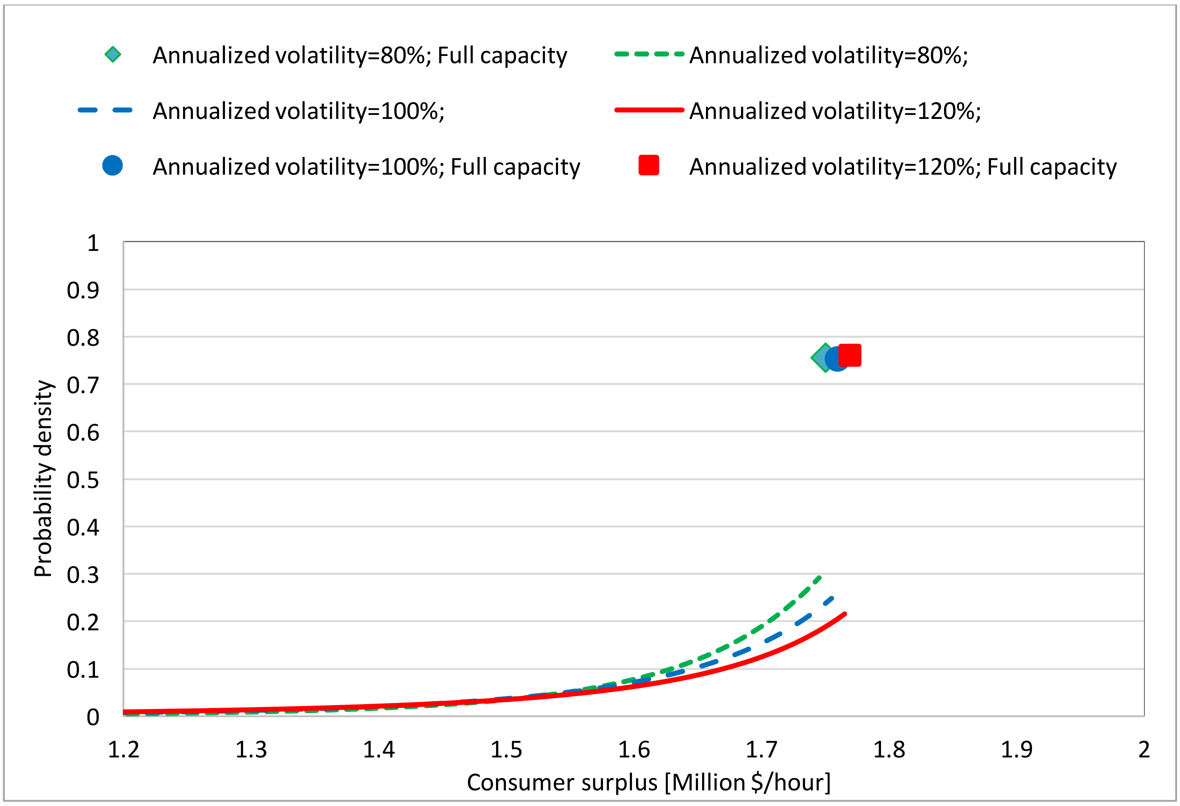
Figure 9-7 depicts the distribution of the producers' profits as a function of natural gas price volatility. The increase in per MWh fuel cost volatility affects the producer's profit in two ways: (a) lower electricity prices reduce profits; and (b) lower per MWh fuel costs improve profits. The overall effect is that rising per MWh fuel cost volatility increases expected profits, as proved in Proposition 5-2(a). Note that the profit probability density does not accumulate at one point, because at the range of generation costs, $0 < c_t < c_{ki}$, generation and price are constant, but smaller generation costs results in higher profits.

Figure 9-7: Distribution function of profits (*N*=5)



Finally Figure 9-8 depicts the distribution function of consumer surplus, as a function of natural gas price volatility. The large bold dots in the graph show the concentration of the probability of the value of the consumer surplus at a single value, separately for each annualized volatility level, reflecting the (fixed) value of the consumer surplus when the market generates electricity at full capacity. This concentration of the probability occurs because there is a range of generation costs, $0 < c_t < c_{ki}$, for which generation is equal to full capacity and, therefore, consumer surplus is constant. For example, for an annualized volatility of 100%, 75% of the probability occurs at a consumer surplus of $1.76 Million/hour, reflecting generation at full capacity. The graph also shows that expected consumer surplus increases with volatility, because higher volatility implies a larger optimal capacity.

Figure 9-8: Distribution function of consumer surplus (*N*=5)



In summary, Figures 9-5 to 9-8 show that an increase in natural gas price volatility increases generation capacity and equilibrium quantity, decreases the average electricity price and increases average profits and consumer surplus, as predicted in Chapter 5. These effects are small, even though the response of the market electricity price and quantity on a particular day to a change in fuel cost[42] may be very large.

[42] We calculated per MWh fuel costs for each day in a year for five different values of annualized volatility (40%, 60%, 80%, 100% and 120%). We repeated this process 100 times. Then, for a given optimal capacity, we calculated electricity prices, industry production, profits and consumer surplus for each day in the year. The results of these simulations show, as is stated in Proposition 5-2, that the average electricity price decreases when fuel cost volatility increases, though not by much: from $150/MWh for $\sigma_{c_t} = 40\%$ to $148/MWh for $\sigma_{c_t} = 120\%$. Consequently, industry production increases by 0.3%, industry profits by 0.8% and consumer surplus by 0.7% when per MWh fuel cost volatility increases from

9.3 Real world example of Chapter 6: The value of hedging

This section demonstrates the effect of hedging on producers' profits. Recall from Chapter 6 that hedging is based on buying call options on the price of natural gas in Stage 2 to create a cap for the price of natural gas in stage 3. Stages 2 and 3 are repeated daily. If the price of natural gas generation, in stage 3, exceeds the strike price, then the firm can buy the gas at the strike price. Otherwise the firm buys the gas at the spot price.

The demonstration of hedging refers to a California style market with 5 firms as in Section 9.1, with 100% annualized natural gas price volatility.

Figure 9-9 demonstrates the effect of hedging on an industry's profits distribution. First, the profit function is shifted to lower values due to the hedging cost. The revenue shift is significant: ~\$5.9 /MW per hour[43] hedging cost per hour, compared to a basic capacity cost of ~\$11.8/MW per hour. Second, hedging creates a floor for the industry's profit at 3.45 million dollars per hour, because the call option implies a cap for the fuel cost thus avoiding the possibility of smaller profits.

Despite of the benefit of the profit floor, the firms' optimal strategy is not to hedge generation cost, because the probability of high fuel cost is small (~25%)[44] and the cost of hedging is significant, therefore decreasing the net expected profit.

40% to 120%. Note, however, that these changes may be substantial in extreme cases. For example, when annualized volatility was 120%, the per MWh fuel cost reached a maximum (minimum) value of \$240 (29) /MWh in one simulation and only \$30 (1.3)/MWh in another. The average (maximum) electricity price reached \$214 (316) /MWh in the first case and only \$143 (143) /MWh in the second.

[43] Using the Black-Scholes option value model with a volatility of 100%, hedging cost is calculated as the value of a call option struck at the price of natural gas for which the firm would generate at full capacity ($c_{K_i} = \$35.9/MWh$). We assume that the hedging stage (Stage 2) is repeated before each time step, t=*1…365*. Hedging cost is calculated for each MW and for each hour over the course of the day, therefore the units of the hedging cost are \$/MW per hour.

[44] Assuming a lognormal distribution with a mean -0.46 and 100% volatility and an initial fuel cost of \$29.5/MWh.

Figure 9-9: The effect of hedging on profits

Consumer surplus increases when the generation cost is hedged, because hedging limits the risk of retail price spikes, due to fuel cost spikes. Note that consumers benefit from hedging without bearing the cost. In this example, the strike price of the call options is equal to the highest fuel cost for which the firm would generate at full capacity, $s = c_{K_i}$. Using equation [6.2], electricity generation is equal to the capacity $Q_{it} = K_i$. Therefore, equilibrium price and consumer surplus are constant, reflecting consumer surplus at full capacity for any fuel cost.

In summary, the firms' optimal strategy is not to use call options for hedging the fuel cost, because of the high hedging cost. Thus, consumers do not gain the potential surplus they could have gained if the fuel cost was hedged.

9.4 Real world example of Chapter 7: Investment in dual fuel capacity

Dual fuel capability is a means of hedging against the risk of high energy costs by fuel switching, whenever the natural gas price is too high, or the natural gas supply is disrupted, see Chapter 7.

Here we use again data from California, assuming that the dual fuel plant is a CCGT plant with the capability of burning diesel fuel instead of natural gas[45]. Dual fuel capability requires on-site storage of liquid fuels, water injection nozzles to reduce NOx emissions, and annual testing of the dual fuel capability. Following Newell et al. (2014, p.14) and Silve et al. (2010, p. 22), we assume that a dual fuel capability increases the capacity cost by 10%. Therefore, the cost of the marginal capacity unit with a dual fuel capability is \$13.07/MWh.

Recall that Proposition 7-2 refers to two possible cases:

Case A (equation [7.11]): In this case, the price of diesel fuel is high, and therefore the expected saving by using natural gas instead of diesel fuel is also high. Proposition 7-2 shows that the use of dual capability would necessarily lead to a smaller capacity investment. We demonstrate this case by assuming a diesel fuel cost of \$80/MWh[46].

Case B (equation [7.12]): In this case, the price of diesel fuel is low, and therefore the expected saving by using natural gas instead of diesel fuel is also low. Proposition 7-1 shows that the use of a dual fuel capability would imply that equilibrium generation would be equal to the capacity for any natural gas generation cost, because the cost of dual fuel generation is smaller than the cost threshold[47] at which the firm would generate at full capacity. We demonstrate this case by assuming a

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[45] Coal-gas plants with dual fuel capabilities are less common and much less efficient compared to dual fuel natural gas plants that can use diesel fuel.

[46] \$80/MWh is equivalent to a price of \$72/barrel, assuming 53% efficiency and 5.8 MMBTU per barrel.

[47] $c_{Ki} > c^d$

diesel fuel generation cost of \$29.5/MWh[48], like the initial natural gas generation cost.

Figure 9-10 depicts the optimal capacity in both a single fuel market and in a dual fuel market. Note that capacity is larger in a dual fuel market only for small values of the dual fuel capability's cost.

Figure 9-10: Dual and single fuel market capacities as a function of the dual fuel cost

N = 5; 100% volatility; c_0=\$29.5 MWh

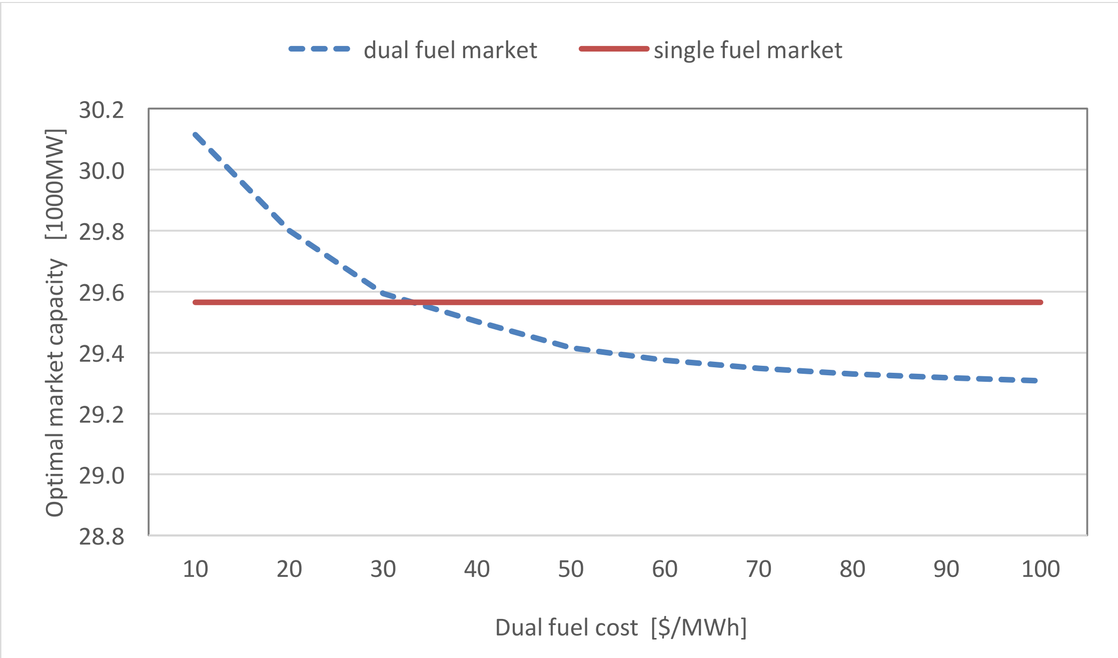


Figure 9-11 depicts the optimal capacity in a dual fuel market as a function of the annualized volatility of the per MWh cost, for two possible values of the dual fuel. Note that the decision to invest in a dual fuel capability, when the per MWh cost of the dual fuel is high, implies a smaller capacity investment.

[48] \$29.5/MWh is equivalent to a price of \$26.5/barrel, assuming 53% efficiency and 5.8 MMBTU per barrel.

Figure 9-11: Dual and single fuel market capacities as a function of annualized volatility

N = 5; c_0=$29.5 MWh

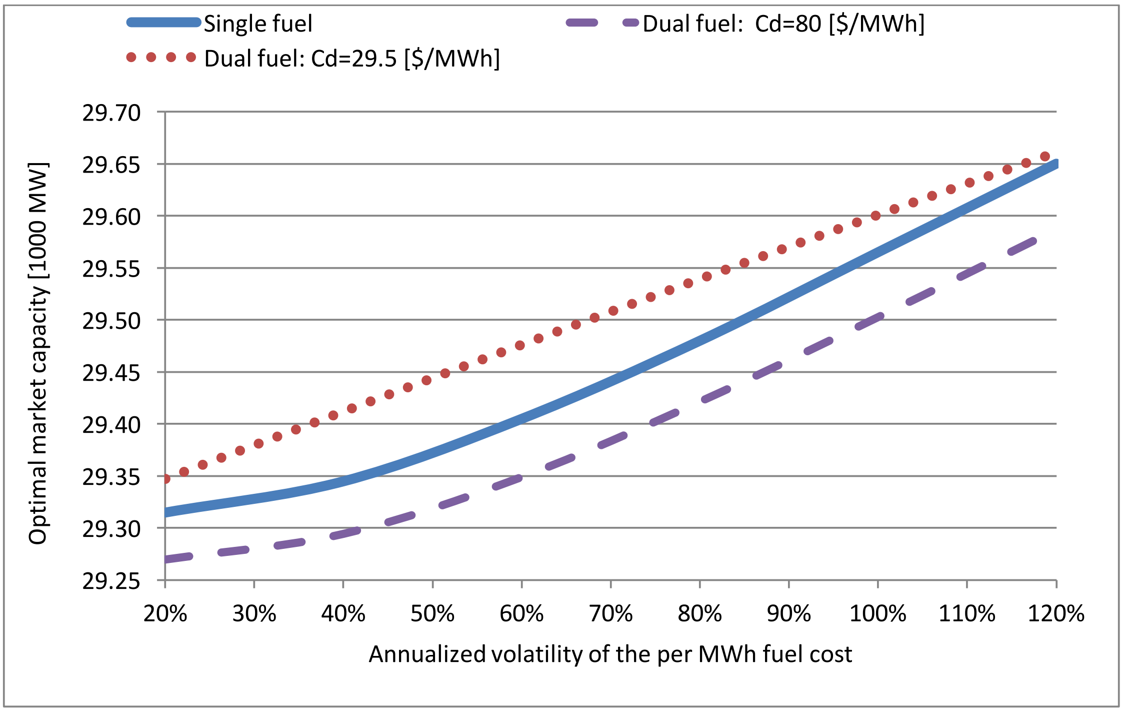


Figure 9-12 depicts producers' net profit in a dual fuel market and in a single fuel market for the two cases of the dual fuel costs. The net profit is equal to the revenues minus fuel costs, minus capacity investment cost.

Note that in both cases the effect of a dual fuel capability is three-fold:

A. **Small profit shift**. The use of dual fuel capability increases capacity cost and therefore slightly cuts the profit. This effect is significantly smaller than the effect of call options discussed in Chapter 6 because the cost[49] of dual fuel capability is smaller than the cost of financial hedging. Note that the profit shift in case B (diesel fuel generation cost = \$29.5/MWh) is slightly more significant because the optimal capacity is larger, thus increasing the dual fuel investment cost.

B. **Profit floor**. Fuel switching hedges against the risk of a high natural gas price, thus creating a floor for the profit distribution. As expected, a smaller dual fuel cost implies a higher floor for the profit distribution. The slight increase of the probability function in the profit floor reflects that the firm would gain whenever the effective fuel cost is higher than the dual fuel capability's cost.

C. **Accumulation of the probability density function at the value of the dual fuel.** The firms' generation cost is equal to the dual fuel generation cost whenever the natural gas-fired generation's cost exceeds that of the dual fuel generation. Therefore, the probability density function accumulates at a point reflecting the profit of the firm when generating with the dual fuel. The accumulation (denoted by a large bold dot at the graph) reflects the probability of the natural gas generating cost exceeding the dual fuel generation cost. Note that a smaller dual fuel generation cost (i.e. \$29/MWh) implies a concentration of the probability density function at a higher consumer surplus value, because the probability of c_t being larger than c^d increases as the value of c^d is smaller.

[49] The cost of dual fuel capability is ~\$1.2/MW per hour, compared to a hedging cost of ~\$5.6/MW per hour.

Figure 9-12: The distribution function of profits in a single and dual fuel market

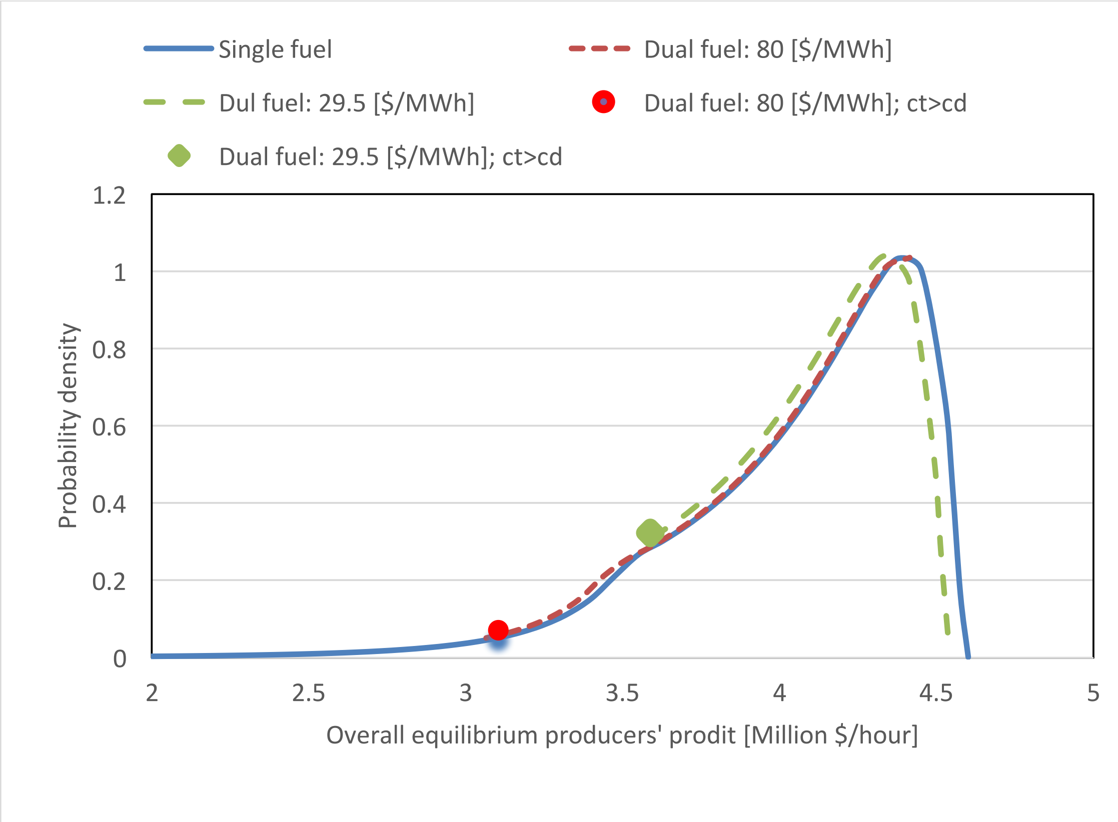
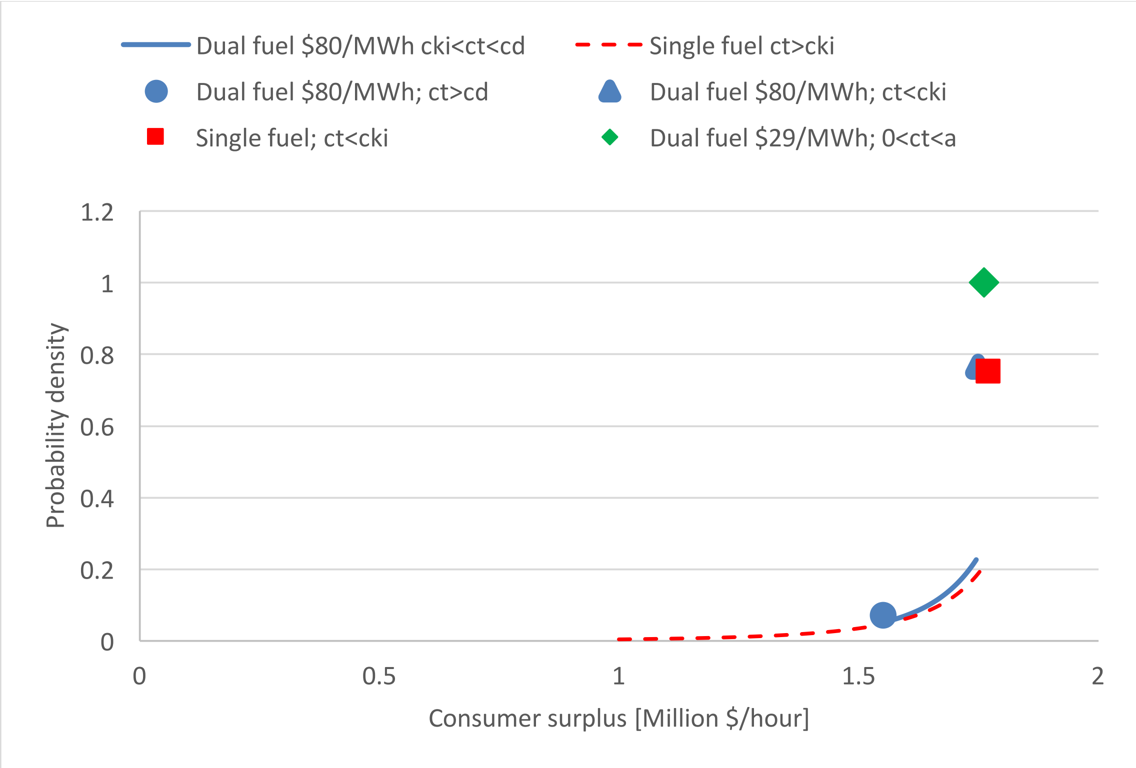


Figure 9-13 depicts the probability density function of the consumer surplus in a dual fuel market. In the single fuel case, consumer surplus peaks at the range of fuel costs smaller than c_{K_i} and decreases for higher values of fuel costs.

In case A, where dual fuel cost is high ($80/MWh), optimal capacity is smaller than in a single fuel market. Therefore, consumer surplus peaks at a slightly smaller value. Also, in this case, small values of the consumer surplus, owing to high generation costs, are prevented due to the dual capability (the probability density function at these values accumulates at a point reflecting the dual fuel cost (denoted by a blue dot).

In case B (denoted by a green dot), where dual fuel cost is low, capacity is constant for any generation cost and, therefore, consumer surplus is constant. In this case, consumers' surplus peaks at a slightly higher value because capacity is higher compared to a single fuel market.

Figure 9-13: The distribution function of consumer surplus in a single and dual fuel market



In conclusion, consumers benefit from dual fuel capability, especially when the dual fuel cost is low. Producers gain a profit floor if they install dual fuel capability, but they also bear the additional cost of investing in this technology, which tends to reduce profit.

9.5 Real world example of Chapter 8: Investment in technology mix

This section illustrates optimal capacity mix in competitive markets (Chapter 8).

In this section, we use here stylized data of Texas, assuming 5 firms, 100% volatility, an initial natural gas generation cost of $29.5MWh, and a marginal capacity cost of $11.88 /MWh.

The coal capacity cost refers to an ICGT plant with $\theta^c = \$26.72/\text{MWh}$, based on a $2290/kw total installation cost, 6% WACC, 20 years' depreciation and $34.4/KW/year fixed cost (NREL, 2010). We study three levels of coal price: $25/MWh, $15/MWh and $9/MWh, reflecting a price of $34.9/ton, $19.4/ton and $8.7/ton respectively[50]. We also assume a heat rate of 11.4 MMBTU/MWh and a variable cost of $4.0/MWh (NREL, 2010).

Recall that Proposition 8-2 refers to two possible cases:

- Case A. The price of coal is low compared to the initial price of natural gas, and the net expected saving of using natural gas - when the price of natural gas is cheaper than the price of coal - is negative. In this case, we expect the optimal capacity to consist of a mix of natural gas and coal capacities. We demonstrate this case with an initial natural gas cost of $29/MWh and a coal fuel cost of $15/MWh and $9/MWh.
- Case B. The price of coal is high relative to the initial price of gas. The net expected saving of using natural gas - when the price of natural gas is cheaper than the price of coal - is positive. In this case, we expect the optimal capacity to consist of natural gas capacity only. We demonstrate this case with an initial natural gas cost of $29.5/MWh and a coal price of $25/MWh.

Figure 9-14 depicts the optimal capacities in case B, in which the initial cost of coal generation is small (i.e. $9/MWh). For volatility values smaller or equal to 80%, scenario 1 is valid, and we find that the optimal capacity consists of coal capacity only, as expected. When the volatility value exceeds 100%, the probability of the natural gas generation cost

[50] Assuming 19.4 MMBTU per one ton of coal

falling below coal generation cost increases, in which case scenario 2 is valid and the firm would invest in some gas capacity.

Figure 9-14: Optimal market capacities in a one- and two-technology market

c^c=\$9/MWh, c_0=\$29.5/MWh

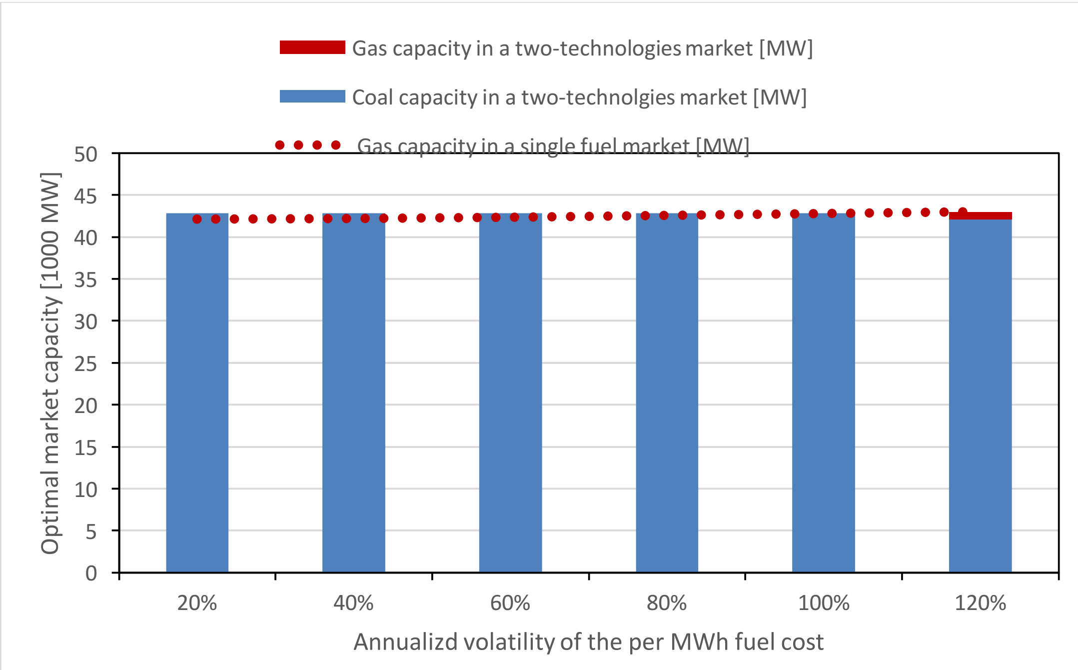


Figure 9-15 depicts optimal technology mix in scenario 2 where natural gas expected fuel cost saving is positive, but smaller than coal expected fuel cost saving. In this case, the firm would invest in a mix of coal capacity and natural gas capacity. The share of gas capacity increases with natural gas cost volatility, as expected by proposition 8-3.

Finally, Figure 9-16 depicts optimal market capacity in scenario 3, where natural gas expected fuel cost saving is larger than that of coal. In this case, the probability of natural gas generation cost falling below coal generation cost is high (67% probability for 100% volatility), and the firm would invest in gas capacity only. In this case, optimal capacity is equal to that of a single fuel market. Note that in this case the firms refrain from investment in coal capacity even though the initial gas generation cost is higher than coal generation cost.

Figure 9-15: Optimal capacities in a one- and two-technology market

$$\mathbf{c^C = \$15/MWh,\ c_0 = \$29.5/MWh}$$

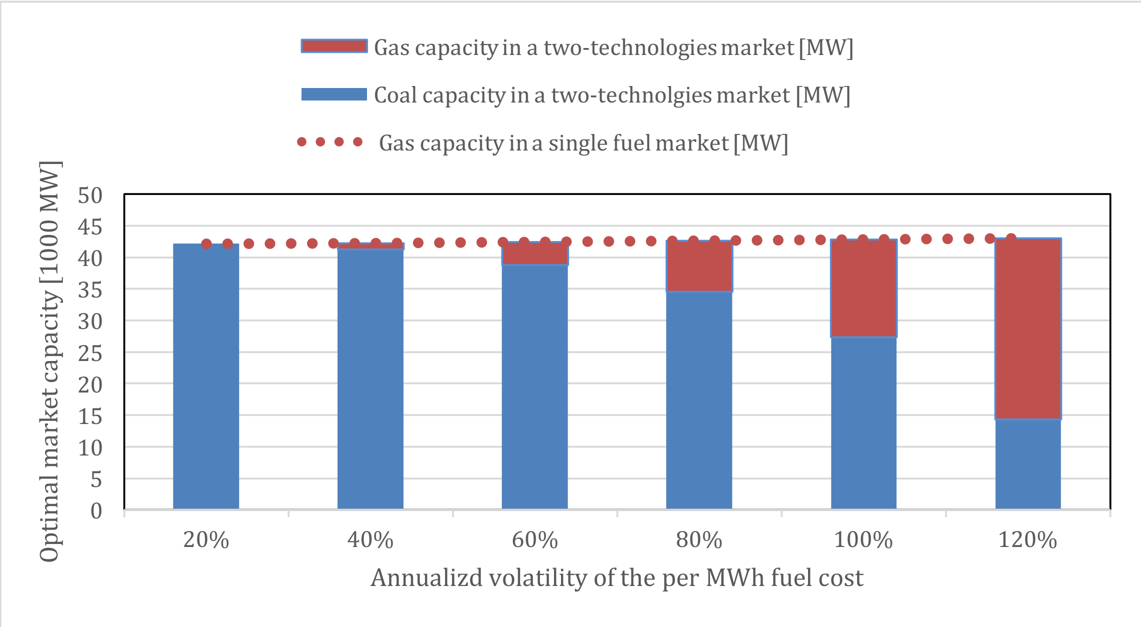


Figure 9-16: Optimal gas capacity in a one- and two-technology market

$$\boldsymbol{c^C = \$25/MWh \quad c_0 = \$29.5/MWh}$$

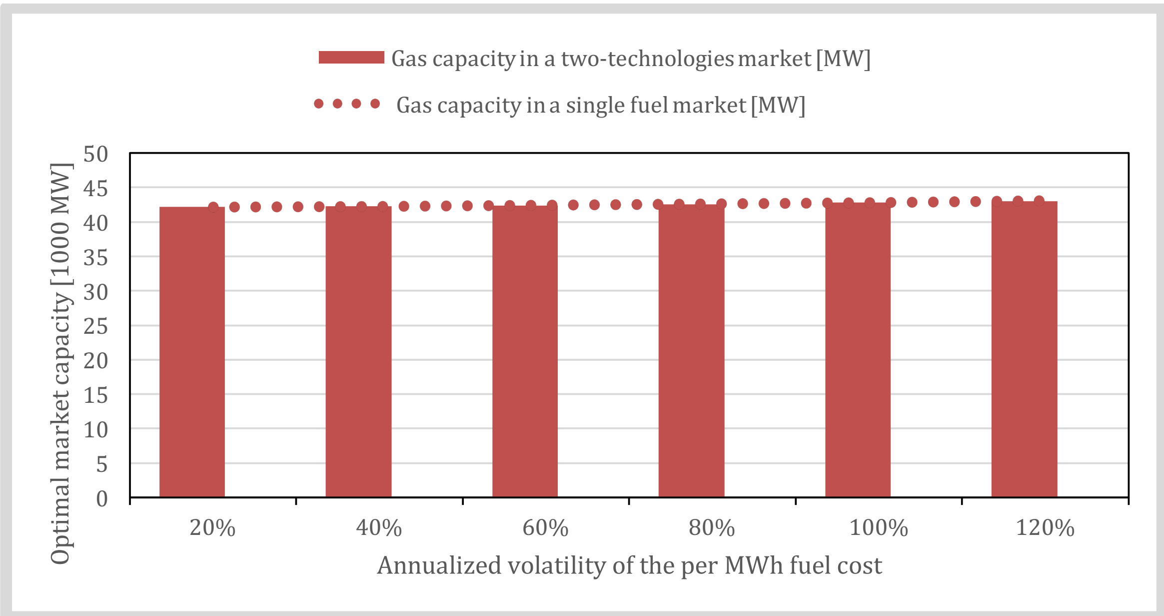


Figure 9-17: The distribution function of profits in a one- and two-technology market

$\mathbf{volatility} = \mathbf{100\%}$; $\boldsymbol{N} = \mathbf{5}$; $\mathbf{c_0}$ = \$29.5/MWh

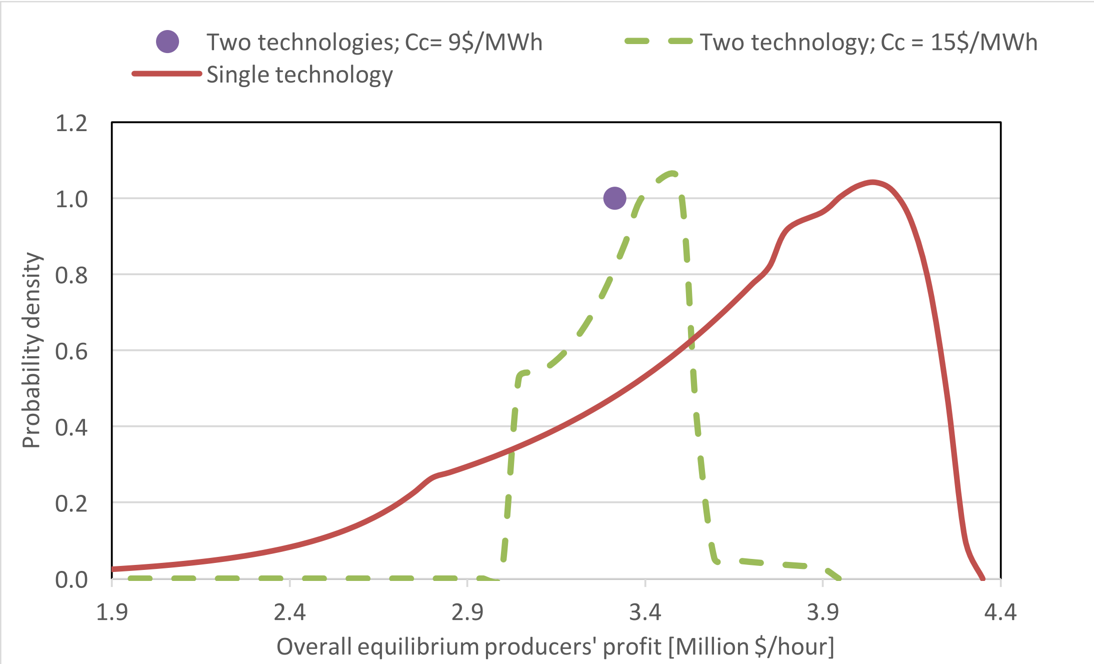


Figure 9-17 depicts distribution functions of producers' profit in a single technology vs. two technology market. As before, the use of technology mix as a means of hedging fuel cost risk has two effects: First, the profit is shifted to lower values due to the increased capacity cost[51]. Second, the use of two technologies creates a cap and a floor for the producers' profit, because the introduction of coal to capacity mix limits the exposure of the firms to the volatility of natural gas price. In other words, coal capacity limits the loss of the firm when the price of natural gas increases, but it also limits the benefit of the firm when the price of natural gas declines. The effect is stronger when the price of coal is lower (i.e. \$9/MWh), because in this case the share of coal in the capacity mix is larger.

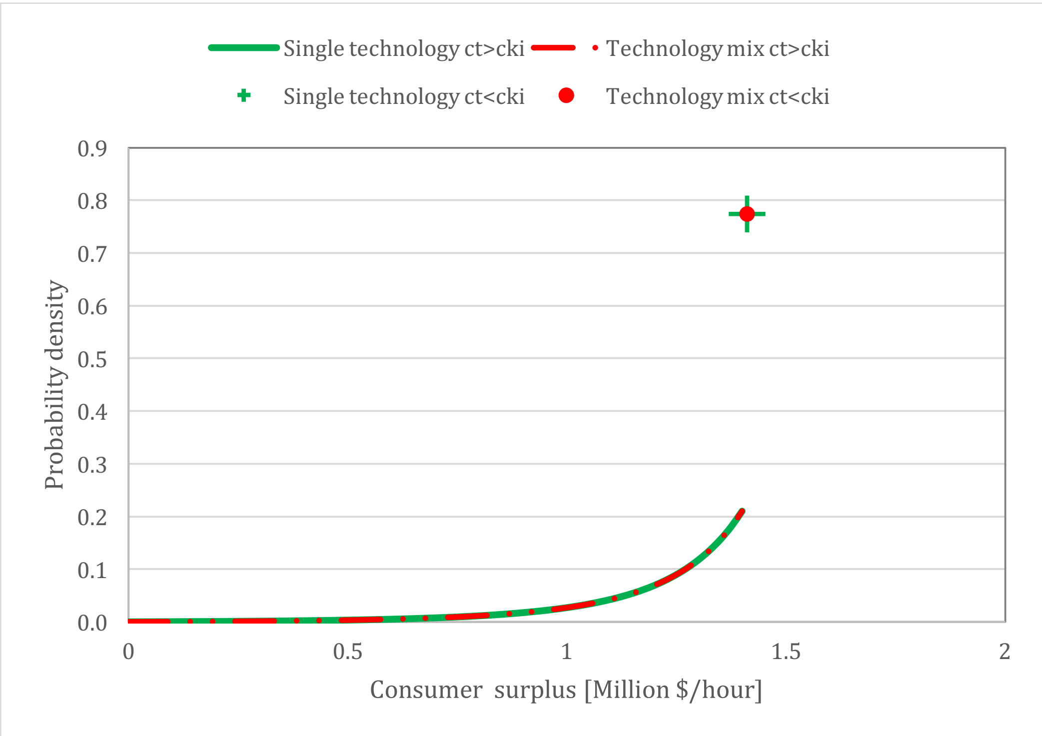
[51] The average market capacity cost increases from 0.51 million dollars per hour in a single-technology market to 0.91 million \$/hour in the case of coal price=\$15/MWh and 1.14 million dollars per hour in the case of coal price = \$10/hour, i.e., a technology mix shifts the profit to lower values by ~0.4-0.6 million dollars per hour.

Hence, the probability density function accumulates at one point (denoted by a purple dot in the graph).

Figure 9-18 depict consumer surplus in a single- and two technology market. Note that optimal capacity, equilibrium generation, and equilibrium price are identical in these markets. Therefore, the distribution function of consumer surplus is also identical in these two markets. Hence, while the technology mix affects the distribution of profits, consumers are unaffected by this hedging strategy.

Figure 9-18: Consumer surplus in a one- and two-technology market

$$\textbf{volatility} = \textbf{100\%}; \quad \textbf{N} = \textbf{5}; \ \textbf{c}_0 = \textbf{\$29.5/MWh}$$



In conclusion, the use of a technology mix provides an effective hedge against the risk of high fuel cost, but it also limits the firm's exposure to the possibility of low natural gas prices, thus limiting the probability of high profits. The effect of a technology mix increases as the price of coal declines, because a lower coal generation cost implies a higher share of coal in the capacity mix. Unlike dual fuel plants, a technology mix does not affect consumer surplus because overall market capacity, equilibrium generation and equilibrium price are not altered.

9.6 Comparison of physical hedging methods

In this section, we compare the firms' profit distribution in a single fuel market versus two possible means of hedging the fuel cost risk: constructing a dual fuel capability or using a technology mix. The comparison refers to two possible scenarios regarding the alternative fuels: low values ($9/MWh for coal generation and $29.5/MWh for diesel generation) and high values ($15/MWh for coal generation and $80/MWh for diesel generation).

Figure 9-19: The distribution function of profits in a single fuel, dual fuel and technology mix markets, when the cost of the alternative fuel is low

$c^C = \$9/\text{MWh};\ c_0 = \$29.5/\text{MWh};\ c^d = \$29.5/\text{MWh}; \text{N=5};\ \text{volatility} = 100\%;$

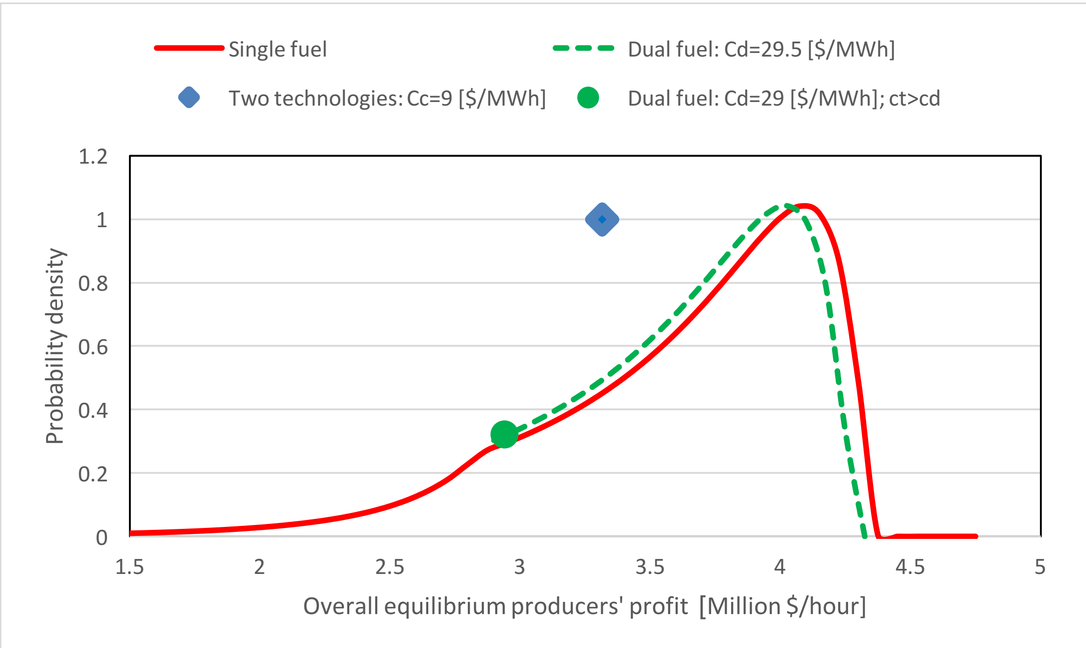
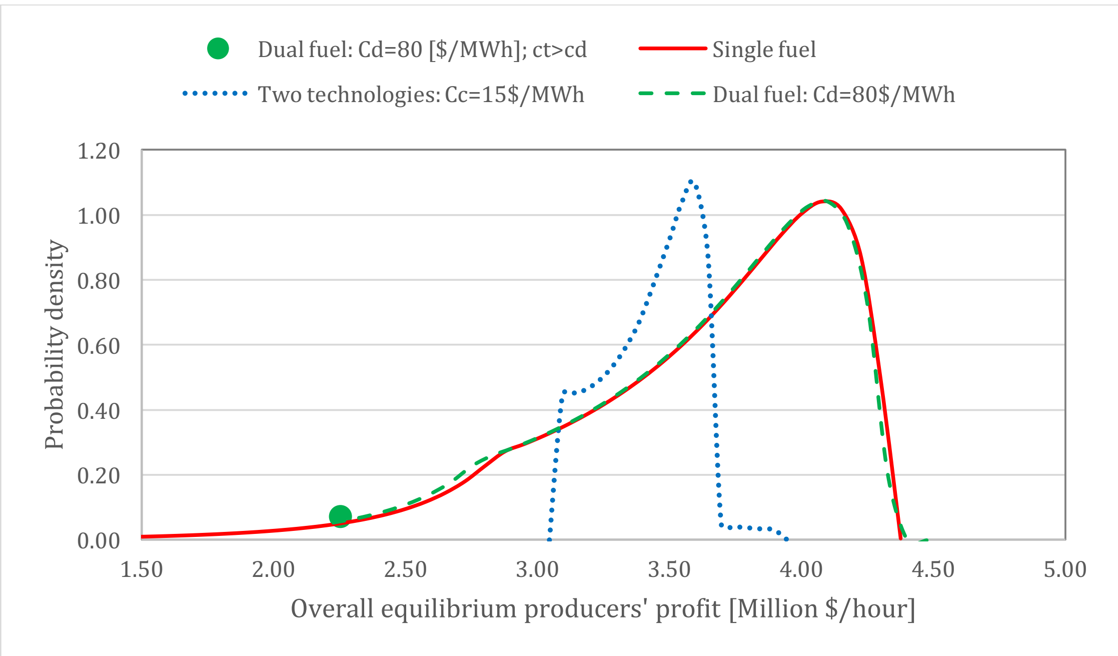


Figure 9-19 compares the firm's strategies of the firm in a scenario reflecting low costs of the alternative fuels. Note that the use of the dual fuel prevents the possibility of the market profits falling below \$2.75 million per hour and the additional capacity cost slightly shifts the profit function to lower values. However, the use of a technology mix shifts the profit function more significantly to smaller values due to the much higher capacity costs. In this case the probability density function accumulates at one point (denoted by a blue dot), reflecting the profit of a coal only market. Therefore, the choice between the two hedging strategies should be related to the firm's risk taste: highly risk-averse firms would prefer a capacity mix, while a risk seeking firm would prefer a dual fuel capability.

Figure 9-20 provides a similar comparison for a scenario reflecting the high cost of the alternative fuels. Note that in this case the effect of both options is less significant. Yet, the use of a capacity mix effects both sides of the profit distribution function and the effect is more significant than that of a dual fuel capability.

Figure 9-20: The distribution function of profits in a single fuel, dual fuel and technology mix markets, when the cost of the alternative fuel is high

$\mathbf{c^C = \$15/MWh;\ \ c_0 = \$29.5/MWh;\ \ c^d = \$80/MWh;\ \ N{=}5;\ \ \sigma = 100\%;}$



10. Summary and conclusions

Natural gas prices in a competitive wholesale market are volatile, more so than the prices of other fossil fuels. Hence, large natural-gas price spikes occasionally occur, exposing IPPs to high natural gas fuel costs and low profits. Thus, the introduction of competition into the electricity market exposes IPPs to risks previously borne by end-users.

This dissertation extends Tishler et al. (2008b) and Milstein and Tishler (2012) to study the effect of natural-gas cost risk on capacity investment in an oligopolistic electricity market. Under the empirically reasonable assumption that per MWh fuel costs are log-normally distributed, we find that optimal capacity investment increases with fuel cost volatility. This is because rising volatility increases the probability of low fuel costs which, in turn, increases the IPP's profits. The increase in installed capacity lowers electricity prices and increases generation output, thus improving consumer welfare.

Despite the positive effect of natural gas price volatility on the expected profits and optimal capacities, firms may still consider the possibility of hedging the price risk to avoid the risk of profits declining below the debt service. In this study, we explore three possible means of hedging fuel cost risk: (1) the use of call options to create a cap for fuel cost at the strike price; (2) the use of dual fuel capabilities which physically hedges the fuel cost risk (e.g. the plant can switch to an alternative fuel as the price of gas increases); and (3) the use of technology mix, which may limit the exposure of the firm to natural gas price volatility.

We demonstrate that the use of call options to hedge natural gas fuel cost increases consumer welfare by mitigating electricity retail price spikes related to fuel cost spikes. However, profit-maximizing electricity producers are unwilling to use call options to hedge against fuel cost spikes because the cost of hedging is higher than the expected gain for the producers.

Second, we develop a framework for analyzing investment in dual fuel plants in a market with uncertain natural gas prices. The dual capability is used as a hedging strategy to protect against fuel price risk. We find that low values of consumer surplus are avoided when dual fuel capability is used. Producers' profit and consumer surplus may decline due to the additional cost of the dual fuel capability, which in turn leads to a smaller capacity, but the firms gain a cap for the fuel cost which implies a floor for the profit distribution function. The effect of using dual fuel capability is larger for both consumers and producers when the dual fuel cost is low.

Finally, we extend the model to study optimal capacity mix in a market with natural gas and coal generation technologies, where the natural gas fuel cost is volatile and the coal fuel cost is known and stable. We find that the firm would choose to introduce coal capacity into its capacity mix only if coal generation cost is significantly lower than the average natural gas generation cost. Also, the optimal share of coal capacity would decline as the volatility of natural gas increases, because higher volatility implies higher possibility of benefiting from lower generation cost when using natural gas. When introducing coal to the mix, producers see a smaller exposure to natural gas price volatility, limiting the possibility of very low or very high profits. In other words, the introduction of coal to the capacity mix implies both a floor and a cap for the producers' profit. Unlike other means of hedging, consumers are not affected by the capacity mix because overall optimal market capacity and equilibrium generation and price are unaffected by the capacity mix.

Overall, consumers benefit from the use of call options or dual fuel capability, more so when dual fuel cost is low. Producers benefit from dual fuel capability and technology mix, though a dual fuel capability might be more attractive since it limits only the down side of high fuel cost, without limiting the possibility of high profits related to low fuel costs. Therefore, a dual fuel capability, given low costs of the alternative fuels, can benefit both consumers and producers.

Our findings highlight the gap between the producers' and consumers' preferences for risk taking. The policy implication, however, is clear: the government should not intervene to reduce the price volatility of a well-functioning competitive natural gas spot market because such an action can have the unintended consequence of discouraging generation investment, raising electricity prices, and reducing consumer surplus.

We would be remiss had we ignored two important limitations to our model presented herein. First, our model only characterizes a simplified electricity market with identical (symmetric) firms, thus abstaining from the reality of heterogeneous power plants with different heat rates (e.g., high, medium and low). Second, the cost of alternative fuels such as coal and diesel is constant in our study, while in reality, these prices are also moderately volatile. Finally, the models presented here do not include all real life market developments (conditions). Forward (bilateral or other) contracting, for example, which may also affect social welfare in oligopolistic markets (see Bushnell, 2007), is left for future research.

Appendix

Proof of Proposition 5-1

The expected marginal profit of a profit-maximizing firm in oligopolistic competition on day *t* is:

[A.1] $$e^{-rt}\int_0^{c_{K_i}}(c_{K_i}-c_t)\cdot g(c_t)dc_t,$$

where

[A.2] $$c_{K_i}\equiv a-bK_i-bQ_{-it}.$$

We must show that, for any time *t*:

[A.3] $$\frac{\partial}{\partial\sigma_{c_t}}e^{-rt}\int_0^{c_{K_i}}(c_{K_i}-c_t)\cdot g(c_t)dc_t>0.$$

Using Lee et al. (2010), we have that if $\frac{c_t}{c_0}$ follows a lognormal distribution, and $\mu=r-\frac{\sigma_{c_t}^2}{2}$, then [A.1] can be rewritten as:

[A.4] $$e^{-rt}\int_0^{c_{K_i}}(c_{K_i}-c_t)\cdot g(c_t)dc_t=c_{K_i}e^{-rt}\Phi(-d_2)-c_0\cdot\Phi(-d_1),$$

where $\Phi(\cdot)$ is the standard cumulative normal distribution function, *r* is the riskless interest rate

[A.5] $$d_1=\frac{ln\left(\frac{c_0}{c_{K_i}}\right)+(r+\frac{1}{2}\sigma_{c_t}^2)t}{\sigma_{c_t}\sqrt{t}},\ \text{and}\quad d_2=d_1-\sigma_{c_t}\sqrt{t}=\frac{ln\left(\frac{c_0}{c_{K_i}}\right)+(r-\frac{1}{2}\sigma_{c_t}^2)t}{\sigma_{c_t}\sqrt{t}}.$$

Differentiating the right-hand side of [A.4] with respect to σ_{c_t} yields:

[A.6] $$\frac{\partial}{\partial\sigma_{c_t}}\left[e^{-rt}\int_0^{c_{K_i}}(c_{K_i}-c_t)\cdot g(c_t)dc_t\right]=c_{K_i}e^{-rt}\frac{\partial\Phi(-d_2)}{\partial d_2}\cdot\frac{\partial d_2}{\partial\sigma_{c_t}}-c_0\frac{\partial\Phi(-d_1)}{\partial d_1}\cdot\frac{\partial d_1}{\partial\sigma_{c_t}}$$

where $\frac{\partial\Phi(-d_1)}{\partial d_1}=-\phi(-d_1)$, $\frac{\partial\Phi(-d_2)}{\partial d_2}=-\phi(-d_2)$, and $\phi(\cdot)$ is the normal density function. Therefore,

[A.7] $$\phi(-d_1)=\frac{1}{\sqrt{2\pi}}e^{-\frac{1}{2}{d_1}^2},\ \phi(-d_2)=\phi\left(\sigma_{c_t}\sqrt{t}-d_1\right)=\frac{1}{\sqrt{2\pi}}e^{-\frac{1}{2}\left(\sigma_{c_t}\sqrt{t}-d_1\right)^2}$$

Thus, we can rewrite [A.6] as follows:

[A.8] $$\frac{\partial}{\partial \sigma_{c_t}}\left[e^{-rt}\int_0^{c_{K_i}}(c_{K_i}-c_t)g(c_t)dc_t\right] = -c_{K_i}e^{-rt}\phi(-d_2)\cdot\frac{\partial d_2}{\partial \sigma_{c_t}} + c_0\phi(-d_1)\cdot\frac{\partial d_1}{\partial \sigma_{c_t}} \quad = -c_{K_i}e^{-rt}\frac{1}{\sqrt{2\pi}}e^{-\frac{1}{2}\left(\sigma_c\sqrt{t}-d_1\right)^2}\cdot\frac{\partial d_2}{\partial \sigma_{c_t}} + c_0\frac{1}{\sqrt{2\pi}}e^{-\frac{1}{2}d_1{}^2}\cdot\frac{\partial d_1}{\partial \sigma_{c_t}}.$$

Using [A.5], c_{K_i} may be written as follows:

[A.9] $$c_{K_i} = c_0 e^{-d_1\sigma_c\sqrt{t}+\left(r+0.5\sigma_c{}^2\right)t}.$$

Inserting [A.9] into [A.8] and rewriting:

[A.10] $$\frac{\partial}{\partial \sigma_{c_t}}\left[e^{-rt}\int_0^{c_{K_i}}(c_{K_i}-c_t)\cdot g(c_t)dc_t\right] =$$

$$= \left[-c_0 e^{-d_1\sigma_{c_t}\sqrt{t}+\left(r+0.5\sigma_c{}^2\right)t}e^{-rt}\frac{1}{\sqrt{2\pi}}e^{-\frac{1}{2}\left(\sigma_{c_t}\sqrt{t}-d_1\right)^2}\frac{\partial d_2}{\partial \sigma_{c_t}} + c_0\frac{1}{\sqrt{2\pi}}e^{-\frac{1}{2}d_1{}^2}\frac{\partial d_1}{\partial \sigma_{c_t}}\right]$$

$$= \left[-c_0\frac{1}{\sqrt{2\pi}}e^{-\frac{1}{2}d_1{}^2}\frac{\partial d_2}{\partial \sigma_{c_t}} + c_0\frac{1}{\sqrt{2\pi}}e^{-\frac{1}{2}d_1{}^2}\frac{\partial d_1}{\partial \sigma_{c_t}}\right]$$

$$= c_0\frac{1}{\sqrt{2\pi}}e^{-\frac{1}{2}d_1{}^2}\left[\frac{\partial d_1}{\partial \sigma_{c_t}} - \frac{\partial d_2}{\partial \sigma_{c_t}}\right]$$

Substituting $d_2 = d_1 - \sigma_{c_t}\sqrt{t}$ in [A.10] yields:

[A.11] $$\frac{\partial}{\partial \sigma_{c_t}}\left[e^{-rt}\int_0^{c_{K_i}}(c_{K_i}-c_t)\cdot g(c_t)dc_t\right] =$$

$$= c_0\frac{1}{\sqrt{2\pi}}e^{-\frac{1}{2}d_1{}^2}\left[\frac{\partial d_1}{\partial \sigma_c} - \left(\frac{\partial d_1}{\partial \sigma_c} - \sqrt{t}\right)\right] = c_0\frac{1}{\sqrt{2\pi}}e^{-\frac{1}{2}d_1{}^2}\sqrt{t} > 0 \ \blacksquare$$

Next, we show that the optimal capacity investment, K^*, also increases with σ_{c_t}. The total derivative of [A.11] with respect to the natural gas cost volatility, σ_{c_t}, is:

[A.12] $$\frac{d\left(e^{-rt}\int_0^{c_{K^*}}(c_{K^*}-c_t)\cdot g(c_t)dc_t\right)}{d\sigma_{c_t}} = 0 = \frac{\partial\left(e^{-rt}\int_0^{c_{K^*}}(c_{K^*}-c_t)\cdot g(c_t)dc_t\right)}{\partial \sigma_{c_t}} + \frac{\partial c_{K^*}}{\partial K^*}\cdot\frac{\partial K^*}{\partial \sigma_{c_t}}.$$

We proved above that the first element in the RHS of [A.12] is positive. Therefore, the second element in the RHS of [A.12] must be negative. By definition, $c_{K^*} \equiv a - K^*\cdot b\cdot(N+1)$, $\frac{\partial c_{K^*}}{\partial K^*} = -b(N+1) < 0$. Therefore, $\frac{\partial K^*}{\partial \sigma_{c_t}} > 0$ $\blacksquare$

Proof of Proposition 5-2

Part a:

[A.13] $E[CS_t] = \int_0^a g(c_t) \cdot \frac{1}{2} \cdot (a - P_t) \cdot Q_t dc_t.$

Inserting the equilibrium solution, we get:

[A.14] $E[CS_t|K^*] = \int_0^{c_{K^*}} g(c_t) \cdot \frac{1}{2} \cdot b(NK^*)^2 dc_t + \int_{c_{K^*}}^a g(c_t) \cdot \frac{1}{2} \cdot \frac{N^2(a-c_t)^2}{b(N+1)^2} dc_t.$

Applying the chain rule, we get:

[A.15] $\frac{\partial E[CS_t|K^*]}{\partial \sigma_{c_t}} = \frac{\partial E[CS_t|K^*]}{\partial K^*} \cdot \frac{\partial K^*}{\partial \sigma_{c_t}}.$

From Proposition 5-1, we have $\frac{\partial K^*}{\partial \sigma_{c_t}} > 0$. Differentiation of [A.14] with respect to K^* yields

[A.16] $\frac{\partial E[CS_t|K^*]}{\partial K^*} = \int_0^{c_{K^*}} g(c_t) \cdot b \cdot N^2 K^* \, dc_t > 0.$

Therefore, $\frac{\partial E[CS_t|K^*]}{\partial \sigma_{c_t}} > 0$ ■

Inserting the equilibrium solution into [5.10] in Chapter 5, we get:

[A.17] $E[\pi_{it}|K^*] = \int_0^{c_{K^*}} g(c_t) \cdot (a - b \cdot NK^* - c_t) \cdot K^* dc_t + \int_{c_{K^*}}^a g(c_t) \cdot \frac{(a-c_t)^2}{b(N+1)^2} dc_t.$

Applying the chain rule, we get:

[A.18] $\frac{\partial E[\pi_{it}|K^*]}{\partial \sigma_{c_t}} = \frac{\partial E[\pi_{it}|K^*]}{\partial K^*} \cdot \frac{\partial K^*}{\partial \sigma_{c_t}}.$

From Proposition 5-1, we have $\frac{\partial K^*}{\partial \sigma_{c_t}} > 0$. Differentiation of [A.17] with respect to K^* yields:

[A.19] $\frac{\partial E[\pi_{it}|K^*]}{\partial K^*} = \int_0^{c_{K^*}} g(c_t) \cdot [a - b(N+1)K^* - c_t] \, dc_t = \int_0^{c_{K^*}} g(c_t) \cdot (c_{K^*} - c_t) \, dc_t = \frac{\theta}{T} > 0.$

Therefore, $\frac{\partial E[\pi_{it}|K^*]}{\partial \sigma_{c_t}} > 0$ ■

Part b:

[A.20] $E[P_t] = \int_0^a g(c_t) \cdot P_t dc_t.$

Inserting the equilibrium solution, we get:

[A.21] $E[P_t|K^*] = \int_0^{c_{K^*}} g(c_t)(a - bNK^*)dc_t + \int_{c_{K^*}}^a g(c_t) \cdot \frac{(a+Nc_t)}{(N+1)} dc_t.$

Applying the chain rule, we get:

[A.22] $\frac{\partial E[P_t|K^*]}{\partial \sigma_{c_t}} = \frac{\partial E[P_t|K^*]}{\partial K^*} \cdot \frac{\partial K^*}{\partial \sigma_{c_t}}.$

From Proposition 5-2, we have $\frac{\partial K^*}{\partial \sigma_{c_t}} > 0$. Differentiation of [A.21] with respect to K^* yields:

[A.23] $\frac{\partial E[P_t|K^*]}{\partial K^*} = \int_0^{c_{K^*}} g(c_t) \cdot (-bN)\, dc_t < 0.$

Proof of Proposition 5-3

The first-order condition for the optimal capacity is given by [5.21] in Chapter 5, and may be rewritten as follows:

[A.24] $\frac{\Theta}{T} = \int_{c_t=0}^{a} \int_{\varepsilon_t = c_t - c_{K^*}}^{\beta} (c_{K^*} + \varepsilon_t - c_t) f\,(\varepsilon_t) g(c_t) d\varepsilon_t dc_t.$

Assuming $\varepsilon_t \sim U(\alpha, \beta)$, we have:

[A.25] $f(\varepsilon_t) = \frac{1}{(\beta - \alpha)}$

Therefore, we can rewrite [A.29]:

[A.26] $\frac{\Theta}{T} \cdot (\beta - \alpha) = \int_0^a g(c_t) \int_{c_t - c_{K^*}}^{\beta} (c_{K^*} + \varepsilon_t - c_t) \cdot dc_t d\varepsilon_t.$

Integrating with respect to ε_t,, we get:

[A.27] $\frac{\Theta}{T} \cdot (\beta - \alpha) = \int_0^a g(c_t)\, ((c_{K^*} - c_t) \cdot \varepsilon_t + \frac{1}{2}\varepsilon_t^2)|_{c_t - c_{K^*}}^{\beta} dc_t.$

Inserting the limits of the integral and rearranging, we get:

[A.28] $\frac{\Theta}{T} \cdot (\beta - \alpha) = \int_0^a \left(\frac{1}{2} {c_t}^2 - (c_{K^*} + \beta)c_t + \frac{1}{2}(\, c_{K^*} + \beta)^2\right) g(c_t) dc_t.$

Rewriting:

[A.29] $\frac{\Theta}{T} \cdot (\beta - \alpha) = \left(\frac{1}{2}\left(\sigma_{c_t}^2 + E[c_t]^2\right) - (c_{K^*} + \beta)E[c_t] + \frac{1}{2}(c_{K^*} + \beta)^2\right).$

Solving the quadratic equation for $(c_{K^*} + \beta)$, we get:

[A.30] $(c_{K^*} + \beta) = E(c_t) \pm \sqrt{2\frac{\Theta}{T}(\beta - \alpha) - \sigma_{c_t}^2}.$

Substituting $c_{K^*} \equiv (a - bK_i(N+1))$, we find:[52]

$$[A.31] \qquad K^* = \frac{a - E(c_t) + \beta - \sqrt{2\frac{\Theta}{T}(\beta - \alpha) - \sigma_{c_t}^2}}{b(N+1)}.$$

Differentiation of [A.36] with respect to σ_{c_t} yields that the optimal capacity, K^*, is a monotonically increasing function of σ_{c_t} for any $g(c_t)$. ■

Proof of Proposition 6-1

Inserting [5.15] and [5.16] in Chapter 5 into [A.13], we get the expected consumer surplus, given the fuel cost distribution, as a function of R_i:

$$[A.32] \qquad E[CS_t] = \int_0^{c_{K_i}} g(c_t) \cdot \frac{1}{2} \cdot b(K_i + Q_{-it})^2 \, dc_t + \int_{c_{K_i}}^{c_{R_i}} g(c_t) \cdot \frac{1}{8b}(a - c_t + bQ_{-it})^2 dc_t + \int_{c_{R_i}}^{a} g(c_t) \cdot \frac{1}{2} \cdot b(R_i + Q_{-it})^2 \, dc_t,$$

where $c_{R_i} \equiv a - 2bR_i - b \cdot Q_{it}$ and c_{K_i} is given by [A.2].

Differentiation of [A.37] with respect to R_i yields:

$$[A.33] \qquad \frac{\partial E[CS_t]}{\partial R_i} = \int_{c_{R_i}}^{a} g(c_t) \cdot b \cdot (R_i + Q_{-it}) \, dc_t \geq 0 \ ■$$

Proof of Proposition 6-2

The proof of Proposition 6-2 is divided into four parts, depending on the value of the strike price, s.

I. Differentiation of the objective function [6.18] in Chapter 6 with respect to R_i:

$$[A.34] \qquad \frac{\partial E[\pi_{it}|R_i]}{\partial R_i} - \int_{a-2bK_i-bQ_{-it}}^{a} g(c_t) \cdot (c_t - a + 2bK_i + bQ_{-it}) dc_t = \int_{a-2bK_i-bQ_{-it}}^{a-2bR_i-bQ_{-it}} g(c_t)\,[c_t - a + 2bK_i + bQ_{-it}] dc_t + \int_{a-2bR_i-bQ_{-it}}^{a} g(c_t)[(a - 2bR_i - bQ_{-it}) - (a - 2bK_i - bQ_{-it})]\, dc_t - \int_{a-2bK_i-bQ_{-it}}^{a} g(c_t) \cdot (c_t - a + 2bK_i + bQ_{-it}) dc_t = 0.$$

Rearranging [A.34] yields:

[52] Note that the other solution is omitted because it does not satisfy the second-order condition $\frac{\partial^2 E[\pi_{it}|K_i]}{\partial K_i^2} \leq 0$, i.e. $K_i \leq \frac{a + \beta - E(c_t)}{b(N+1)}$.

[A.35] $\int_{c_{K_i}}^{c_{R_i^*}} g(c_t)\left(c_t - c_{K_i}\right)dc_t + \int_{c_{R_i^*}}^{a} g(c_t)\left(c_{R_i^*} - c_{K_i}\right)dc_t -$

$$\int_{c_{K_i}}^{a} g(c_t)\left(c_t - c_{K_i}\right)dc_t = -\int_{c_{R_i^*}}^{a} \mathrm{g}(c_t)\cdot\left(c_t - c_{R_i^*}\right)dc_t = 0,$$

where $c_{R_i^*} \equiv a - bR_i^* - b\cdot Q_{-it}$ andc_{K_i} is given by [A.2].

[A.35] holds if $a = c_{R_i^*}$. That is, $R_i^* = 0$ for $i = 1, \dots, N$.

II. Suppose that $a - 2bK_i - bQ_{-it} < s < a - 2bR_i - bQ_{-it}$. Then, the objective function of firm *i* in Stage 2 is as follows:

[A.36] $E(\pi_{it}|R_i) - R_i\cdot\int_s^a g(c_t)\cdot(c_t - s)dc_t = \int_0^{a-2bK_i-bQ_{-it}} g(c_t)K_i\cdot(a - bK_i - bQ_{-it} - c_t)\,dc_t + \int_{a-2bK_i-bQ_{-it}}^{s} g(c_t)\frac{1}{4b}(a - bQ_{-it} - c_t)^2 dc_t + \int_s^{a-2bR_i-bQ_{-it}} g(c_t)\left[\frac{1}{4b}(a - bQ_{-it} - c_t)^2 + R_i\cdot(c_t - s)\right]dc_t + \int_{a-2bR_i-bQ_{-it}}^{a} g(c_t)R_i\cdot(a - bR_i - bQ_{-it} - \mathrm{s})\,dc_t - R_i\cdot\int_s^a g(c_t)\cdot(c_t - s)dc_t$

Differentiating [A.36] with respect to R_i yields

[A.37] $\int_s^{c_{R_i^*}} g(c_t)\,(c_t - s)dc_t + \int_{c_{R_i^*}}^{a} g(c_t)\left(c_{R_i^*} - s\right)dc_t - \int_s^a g(c_t)\,(c_t -$

$$s)dc_t = -\int_{c_{R_i^*}}^{a} \mathrm{g}(c_t)\cdot\left(c_t - c_{R_i^*}\right)dc_t = 0$$

Thus, $R_i^* = 0$ for $i = 1, \dots, N$.

III. Suppose that $s < a - 2bK_i - bQ_{-it}$. Then, the objective function of firm *i* in Stage 2 is as follows:

[A.38] $E(\pi_{it}|R_i) - R_i\cdot\int_s^a g(c_t)\cdot(c_t - s)dc_t = \int_0^s g(c_t)K_i\cdot(a - bK_i - bQ_{-it} - c_t)\,dc_t + \int_{\mathrm{s}}^{a-2bK_i-bQ_{-it}} g(c_t)[R_i\cdot(a - bK_i - bQ_{-it} - \mathrm{s}) + (K_i - R_i)\cdot(a - bK_i - bQ_{-it} - c_t)]\,dc_t + \int_{a-2bK_i-bQ_{-it}}^{a-2bR_i-bQ_{-it}} g(c_t)\left[\frac{1}{4b}(a - bQ_{-it} - c_t)^2 + R_i\cdot(c_t - s)\right]dc_t + \int_{a-2bR_i-bQ_{-it}}^{a} g(c_t)R_i\cdot(a - bR_i - bQ_{-it} - \mathrm{s})\,dc_t - R_i\cdot\int_s^a g(c_t)\cdot(c_t - s)dc_t$

Differentiating [A.38] with respect to R_i yields:

[A.39] $\int_0^{c_{K_i}} g(c_t)\,(c_t - s)dc_t + \int_{c_{K_i}}^{c_{R_i^*}} g(c_t)\,(c_t - s)dc_t + \int_{c_{R_i^*}}^{a} g(c_t)\left(c_{R_i^*} -\right.$

$$\left. s\right)dc_t - \int_s^a g(c_t)\,(c_t - s)dc_t = -\int_{c_{R_i^*}}^{a} \mathrm{g}(c_t)\cdot\left(c_t - c_{R_i^*}\right)dc_t = 0$$

Thus, $R_i^* = 0$ for $i = 1, \dots, N$.

IV. Suppose that $s = a - 2bR_i - bQ_{-it}$. Then, the objective function of firm *i* in Stage 2 is as follows:

[A.40] $$E(\pi_{it}|R_i) - R_i \cdot \int_{a-2bR_i-bQ_{-it}}^{a} g(c_t) \cdot (c_t - s) dc_t = \int_0^{a-2bK_i-bQ_{-it}} g(c_t) K_i \cdot (a - bK_i - bQ_{-it} - c_t)\, dc_t + \int_{a-2bK_i-bQ_{-it}}^{a-2bR_i-bQ_{-it}} g(c_t) \frac{1}{4b} (a - bQ_{-it} - c_t)^2 dc_t + \int_{a-2bR_i-bQ_{-it}}^{a} g(c_t) R_i \cdot (bR_i)\, dc_t - R_i \cdot \int_{a-2bR_i-bQ_{-it}}^{a} g(c_t) \cdot (c_t - a + 2bR_i + bQ_{-it}) dc_t$$

Differentiating [A.40] with respect to R_i yields

[A.41] $$\int_{c_{R_i^*}}^{a} g(c_t) 2bR_i^*\, dc_t - \int_{c_{R_i^*}}^{a} g(c_t) \left(c_t - c_{R_i^*} + 2bR_i^*\right) dc_t = -\int_{c_{R_i^*}}^{a} g(c_t) \cdot \left(c_t - c_{R_i^*}\right) dc_t = 0$$

Thus, $R_i^* = 0$ for $i = 1, \dots, N$ ■

Proof of Proposition 7-1

The first-order condition of [7.5] in Chapter 7 requires:

[A.42] $$a - b \cdot (2Q_{it} + Q_{-it}) - c_t^{min} = 0,$$

where $Q_{-it} \equiv \sum_{j \neq i} Q_{jt}$. Assuming symmetry of the *N* identical firms, the optimal solution of [7.5] in Chapter 7 is $Q_{it} = K_i$ if $c_t^{min} \leq a - b(N+1)K_i$; otherwise, it is $Q_{it} = \frac{a - c_t^{min}}{b(N+1)}$.

Let $c_{K_i} \equiv a - b(N+1)K_i$. Then, there are two possible cases: $c_{K_i} \leq c^d$ (case A) and $c_{K_i} > c^d$ (case B). For each case, we can build the sequence of non-overlapping intervals of c_t, such that the value of c_t is monotonically increasing.

<u>Case A.</u> If $c_t \leq c_{K_i}$, then $c_t^{min} = c_t$ and $Q_{it} = K_i$. If $c_t > c_{K_i}$ but $c_t \leq c^d$, then $c_t^{min} = c_t$ and $Q_{it} = \frac{a - c_t}{b(N+1)}$. If $c_t > c^d$, then $c_t^{min} = c^d$ and $Q_{it} = \frac{a - c^d}{b(N+1)}$. The equilibrium price is obtained by inserting the equilibrium quantity for each interval of c_t.

<u>Case B.</u> If $c_t \leq c^d$, then $c_t^{min} = c_t$ and $Q_{it} = K_i$. If $c_t > c^d$, then $c_t^{min} = c^d$ and $Q_{it} = K_i$. The equilibrium price is obtained by inserting the equilibrium quantity into [7.1] for each interval of c_t ■

Proof of Proposition 7-2

Case A.

Differentiating [7.7] yields the first-order condition for optimal K_i:

$$\text{[A.43]}\qquad \sum_{t=1}^{T} e^{-rt}\cdot\left[\int_0^{c_{K_i}}[a-2bK_i-bQ_{-it}-c_t]\cdot g(c_t)dc_t-\frac{\Theta+\Psi}{T}\right]=0,$$

Assuming symmetry of all *N* producers, we obtain [9].

Case B.

Differentiating [7.8] yields the first-order condition for the optimal K_i:

$$\text{[A.44]}\qquad \sum_{t=1}^{T} e^{-rt}\cdot\left[\int_0^{c^d}[a-2bK_i-bQ_{-it}-c_t]\cdot g(c_t)dc_t+\int_{c^d}^{\infty}[a-2bK_i-bQ_{-it}-c^d]\cdot g(c_t)dc_t-\frac{\Theta+\Psi}{T}\right]=0$$

Assuming symmetry of all *N* producers and rearranging yield:

$$\text{[A.45]}\qquad \sum_{t=1}^{T} e^{-rt}\cdot\left[\int_0^{c^d}[a-b(N+1)K-c_t]\cdot g(c_t)dc_t-\int_{c^d}^{\infty}[a-b(N+1)K-c^d]\cdot g(c_t)dc_t-\frac{\Theta+\Psi}{T}\right]=\sum_{t=1}^{T} e^{-rt}\cdot\left[[a-b(N+1)K]-\int_0^{c^d}c_t\,g(c_t)dc_t-c^d\int_{c^d}^{\infty}g(c_t)dc_t-\frac{\Theta+\Psi}{T}\right]=\sum_{t=1}^{T} e^{-rt}\cdot\left[[a-b(N+1)K]+\int_0^{c^d}(c^d-c_t)\,g(c_t)dc_t-c^d-\frac{\Theta+\Psi}{T}\right]=\sum_{t=1}^{T} e^{-rt}\cdot\int_0^{c^d}(c^d-c_t)\,g(c_t)dc_t+\frac{e^{-r}(1-e^{-rT})}{1-e^{-r}}\left([a-b(N+1)K]-c^d-\frac{\Theta+\Psi}{T}\right)=0.$$

We obtain the optimal solution:

$$\text{[A.46]}\qquad K^*=\frac{\sum_{t=1}^{T}\left[e^{-rt}\cdot\int_0^{c^d}(c^d-c_t)g(c_t)dc_t\right]}{b(N+1)\cdot\sum_{t=1}^{T}e^{-rt}}+\frac{1}{b(N+1)}\left(a-c^d-\frac{\Theta+\Psi}{T}\right)$$

We also obtain the condition for case B:

$$\text{[A.47]}\qquad c_{K^*}>c^d\Leftrightarrow\sum_{t=1}^{T}e^{-rt}\cdot\int_0^{c^d}(c^d-c_t)\,g(c_t)dc_t<\frac{e^{-r}(1-e^{-rT})}{1-e^{-r}}\cdot\frac{\Theta+\Psi}{T}\ \blacksquare$$

Proof of Proposition 7-3

(I)

Case A. The proof is identical to the proof of Proposition 5-2, since the capacity cost (which is the only part differentiating [7.9] from [5.3]) does not depend on σ_{c_t}.

Case B. Differentiation of [7.10] with respect to σ_{c_t} yields:

[A.48] $$\frac{\partial K^*}{\partial \sigma_{c_t}} = \frac{1}{b(N+1)\cdot\sum_{t=1}^{T} e^{-rt}} \cdot \frac{\partial}{\partial \sigma_{c_t}} \sum_{t=1}^{T} e^{-rt} \int_0^{c^d} (c^d - c_t)\, g(c_t) dc_t.$$

Using the same logic as in the proof of Proposition 5-2, it is clear that

[A.49] $$\frac{\partial}{\partial \sigma_{c_t}} \sum_{t=1}^{T} e^{-rt} \int_0^{c^d} (c^d - c_t)\, g(c_t) dc_t > 0. \text{ That is, } \frac{\partial K^*}{\partial \sigma_{c_t}} > 0.$$

(II)

Case A. The expected operating profits on day *t* in [7.7] at the optimal first-stage solution are given by:

[A.50] $$E[\pi_{it}|K^*] = \int_0^{c_{K^*}} [a - bNK^* - c_t] \cdot K^* g(c_t) dc_t + \int_{c_{K^*}}^{c^d} \frac{1}{b}\left[\frac{a-c_t}{N+1}\right]^2 g(c_t) dc_t + \int_{c^d}^{\infty} \frac{1}{b}\left[\frac{a-c^d}{N+1}\right]^2 g(c_t) dc_t$$

The chain rule implies:

[A.51] $$\frac{\partial E[\pi_{it}|K^*]}{\partial \sigma_{c_t}} = \frac{\partial E[\pi_{it}|K^*]}{\partial K^*} \cdot \frac{\partial K^*}{\partial \sigma_{c_t}}.$$

From part (i), we have $\frac{\partial K^*}{\partial \sigma_{c_t}} > 0$. Differentiation of [A.50] with respect to K^* yields

[A.52] $$\frac{\partial E[\pi_{it}|K^*]}{\partial K^*} = \int_0^{c_{K^*}} [a - b(N+1)K^* - c_t] g(c_t) dc_t = \int_0^{c_{K^*}} (c_{K^*} - c_t)\, g(c_t) dc_t > 0.$$

Therefore, $\frac{\partial E[\pi_{it}|K^*]}{\partial \sigma_{c_t}} > 0$.

Case B. The expected operating profits on day *t* in [7.8] in the optimal first-stage solution are given by:

[A.53] $$E[\pi_{it}|K^*] = \int_0^{c^d} [a - bNK^* - c_t] K^* g(c_t) dc_t + \int_{c^d}^{\infty} [a - bNK^* - c^d] K^* g(c_t) dc_t$$

Differentiation of [A.53] with respect to K_i^* yields

[A.54] $\frac{\partial E[\pi_{it}|K^*]}{\partial K^*} = \int_0^{c^d} [a - b(N+1)K^* - c_t] g(c_t) dc_t + \int_{c^d}^{\infty} [a - b(N+1)K^* - c^d] g(c_t) dc_t = \int_0^{c^d} [c_{K^*} - c_t] g(c_t) dc_t + \int_{c^d}^{\infty} [c_{K^*} - c^d] g(c_t) dc_t.$

As long as $c_{K^*} > c^d$ holds for case B, [A.59] is positive. That is, $\frac{\partial E[\pi_{it}|K^*]}{\partial K_i{}^*} > 0.$

Applying the chain rule and the result of part (i) yields: $\frac{\partial E[\pi_{it}|K^*]}{\partial \sigma_{c_t}} = \frac{\partial E[\pi_{it}|K^*]}{\partial K_i{}^*} \cdot \frac{\partial K^*}{\partial \sigma_{c_t}} > 0.$

(III)

Generally, the expected consumer surplus on day *t* is given by:

[A.55] $E[CS_t] = \int_0^{a} \frac{1}{2}(a - P_t) Q_t g(c_t) dc_t.$

<u>Case A.</u> Inserting the equilibrium solution into [A.55], we get the expected consumer surplus in the optimal solution on day *t*:

[A.56] $E[CS_t|K^*] = \int_0^{c_{K^*}} \frac{1}{2}(b\sum_i K^*) \cdot K_i{}^* g(c_t) dc_t + \int_{c_{K^*}}^{c^d} \frac{1}{2b} \frac{N(a-c_t)^2}{(N+1)^2} g(c_t) dc_t + \int_{c^d}^{a} \frac{1}{2b} \cdot \frac{N(a-c^d)^2}{(N+1)^2} g(c_t) dc_t.$

Applying the chain rule, we get:

[A.57] $\frac{\partial E[CS_t|K^*]}{\partial \sigma_{c_t}} = \frac{\partial E[CS_t|K^*]}{\partial K^*} \cdot \frac{\partial K^*}{\partial \sigma_{c_t}}.$

From part (i), we have $\frac{\partial K^*}{\partial \sigma_{c_t}} > 0$. Differentiation of [A.56] with respect to K^* yields:

[A.58] $\frac{\partial E[CS_t|K^*]}{\partial K_i{}^*} = \int_0^{c_{K_i{}^*}} \frac{1}{2} b(N+1) K_i{}^* g(c_t) dc_t > 0.$

Therefore, $\frac{\partial E[CS_t|K^*]}{\partial \sigma_{c_t}} = \frac{\partial E[CS_t|K^*]}{\partial K^*} \cdot \frac{\partial K^*}{\partial \sigma_{c_t}} > 0.$

<u>Case B.</u> Inserting the equilibrium solution into [A.56], we get the expected consumer surplus in the optimal solution on day *t*:

[A.59] $E[CS_t|K^*] = \int_0^{c^d} \frac{1}{2}(b\sum_i K^*) \cdot K^* g(c_t) dc_t.$

Differentiation of [A.59] with respect to K^* yields: $\frac{\partial E[CS_t|K^*]}{\partial K^*} = \frac{1}{2} b(N+1)K^* > 0.$

Applying the chain rule and the result of part (i) yields: $\frac{\partial E[CS_t|K^*]}{\partial \sigma_{c_t}} = \frac{\partial E[CS_t|K^*]}{\partial K^*} \cdot \frac{\partial K^*}{\partial \sigma_{c_t}} > 0.$

(IV)

Generally, the expected price on day *t* is given by:

$$[\text{A.60}] \qquad E[P_t] = \int_0^a P_t g(c_t) dc_t.$$

<u>Case A.</u> Inserting the equilibrium solution into [A.60], we get the expected price in the optimal solution on day *t*:

$$[\text{A.61}] \qquad E[P_t|K_i^*] = \int_0^{c_{K^*}} (a - b\textstyle\sum_i K^*) g(c_t) dc_t + \int_{c_{K^*}}^{c^d} \frac{a+Nc_t}{N+1} g(c_t) dc_t + \int_{c^d}^{a} \frac{a+Nc^d}{N+1} g(c_t) dc_t.$$

Applying the chain rule, we get:

$$[\text{A.62}] \qquad \frac{\partial E[P_t|K^*]}{\partial \sigma_{c_t}} = \frac{\partial E[P_t|K^*]}{\partial K^*} \cdot \frac{K^*}{\partial \sigma_{c_t}}.$$

From part (i), we have $\frac{\partial K^*}{\partial \sigma_{c_t}} > 0$. Differentiation of [A.61] with respect to K^* yields:

$$[\text{A.63}] \qquad \frac{\partial E[P_t|K^*]}{\partial K^*} = \int_0^{c_{K^*}} (-bN)\, g(c_t) dc_t < 0.$$

Therefore,

$$[\text{A.64}] \qquad \frac{\partial E[P_t|K^*]}{\partial \sigma_{c_t}} = \frac{\partial E[P_t|K^*]}{\partial K^*} \cdot \frac{\partial K^*}{\partial \sigma_{c_t}} < 0.$$

<u>Case B.</u> Inserting the equilibrium solution into [A.61], we get the expected price in the optimal solution on day *t*:

$$[\text{A.65}] \qquad E[P_t|K^*] = \int_0^a (a - b\textstyle\sum_i K^*) g(c_t) dc_t.$$

Differentiation of [A.65] with respect to K_i^* yields: $\frac{\partial E[P_t|K^*]}{\partial K^*} = \int_0^{c_{K^*}} (-bN)\, g(c_t) dc_t < 0.$

Applying the chain rule and the result of part (i) yields: $\frac{\partial E[P_t|K^*]}{\partial \sigma_{c_t}} = \frac{\partial E[P_t|K^*]}{\partial K^*} \cdot \frac{\partial K^*}{\partial \sigma_{c_t}} < 0$ ■

Proof of Proposition 7-4

(I)

<u>Case A</u>

Optimal capacity is independent of c^d. Therefore, $\frac{\partial K^*}{\partial c^d} = 0$

Case B

Differentiation of [7.12] yields:

[A.66] $$\frac{\partial K^*}{\partial c^d} = \frac{-1}{b(N+1)} + \frac{\sum_{t=1}^{T} e^{-rt} \int_0^{c^d} g(c_t)dc_t}{b(N+1)\cdot\sum_{t=1}^{T} e^{-rt}} = \frac{\sum_{t=1}^{T} e^{-rt}[\int_0^{c^d} g(c_t)dc_t - 1]}{b(N+1)\cdot\sum_{t=1}^{T} e^{-rt}}$$

Note that $\int_0^{c^d} g(c_t)\, dc_t < 1$; therefore, $\frac{\partial K^*}{\partial c^d} = \frac{\sum_{t=1}^{T} e^{-rt}[\int_0^{c^d} g(c_t)dc_t - 1]}{b(N+1)\cdot\sum_{t=1}^{T} e^{-rt}} < 0.$

(II)

Case A.

Differentiating [A.50] with respect to c^d, yields:

[A.67] $$\frac{\partial E[\pi_{it}|K^*]}{\partial c^d} = -\frac{1}{(N+1)} \int_{c^d}^{a} \frac{2}{b}\left[\frac{a-c^d}{N+1}\right] g(c_t)dc_t < 0$$

Case B.

Differentiating [A.53] with respect to c^d and applying the chain rule yields:

[A.68] $$\frac{\partial E[\pi_{it}|K^*]}{\partial c^d} = \frac{\partial E[\pi_{it}|K^*]}{\partial K^*} \cdot \frac{\partial K^*}{\partial c^d}, \text{ where } \frac{\partial E[\pi_{it}|K^*]}{\partial K^*} > 0 \text{ and } \frac{\partial K^*}{\partial c^d} < 0,$$

Therefore, $\frac{\partial E[\pi_{it}|K^*]}{\partial c^d} < 0.$

(III)

Case A.

Differentiating [A.56] with respect to c^d, yields:

[A.69] $$\frac{\partial E[CS_t|K^*]}{\partial c^d} = -\int_{c^d}^{a} \frac{1}{b} \cdot \frac{N(a-c^d)}{(N+1)^2} g(c_t)dc_t < 0$$

Case B.

Differentiating [A.59] with respect to c^d and applying the chain rule, yields:

$$\frac{\partial E[CS_t|K^*]}{\partial K_i{}^*} = \frac{1}{2} b(N+1)K^* > 0 \text{ and } \frac{\partial K^*}{\partial c^d} < 0$$

Therefore:

$$[A.70] \qquad \frac{\partial E[CS_t|K^*]}{\partial c^d} < 0$$

(IV)

Case A.

Differentiating [A.61] with respect to c^d, yields:

$$[A.71] \qquad \frac{\partial E[P_t|K^*]}{\partial c^d} = \frac{N}{N+1} \int_{c^d}^{a} g(c_t) dc_t > 0$$

Case B

Differentiating [A.65

] with respect to c^d and applying the chain rule, yields:

$$[A.72] \qquad \frac{\partial E[P_t|K^*]}{\partial K_i^*} = \int_0^a (-2b)\, g(c_t) dc_t < 0 \quad \text{and} \quad \frac{\partial K^*}{\partial c^d} < 0$$

Therefore, $\frac{\partial E[P_t|K^*]}{\partial c^d} > 0$

Proof of Proposition 8-1

K^{G*} and K^{C*}, the optimal capacities of the i-th firm, may be either interior or corner solutions. That is, we have to examine whether the KKT conditions, given by [19], are satisfied simultaneously at each one of the three possible solutions (we do not analyze the trivial solution, i.e. $K^{G*} = 0$ and $K^{C*} = 0$).

Scenario (i). $K^{G*} = 0$ and $K^{C*} \neq 0$, i.e. $\mu_2 = 0$. K^{C*} and μ_1 are given by:

$$[A.73] \qquad K^{C*} = \frac{a - c^C - \frac{\Theta^C}{T}}{b(N+1)}, \text{ and}$$

$$[A.74] \qquad \mu_1 = \frac{e^{-r}(1-e^{-rT})}{1-e^{-r}} \cdot \frac{\Theta^G}{T} - \sum_{t=1}^{T} e^{-rt} \cdot \int_0^{c^C + \Theta^C/T} [c^C + \Theta^C/T - c_t]\, g(c_t) dc_t.$$

Thus, this point is optimal iff 1) $K^{C*} \geq 0$, i.e. $a \geq c^C + \frac{\Theta^C}{T}$, and 2) $\mu_1 \geq 0$, i.e.

$$[A.75] \qquad \frac{e^{-r}(1-e^{-rT})}{1-e^{-r}} \cdot \frac{\Theta^G}{T} \geq \sum_{t=1}^{T} e^{-rt} \cdot \int_0^{c^C + \Theta^C/T} [c^C + \Theta^C/T - c_t]\, g(c_t) dc_t.$$

Scenario (ii). K^{G*} and K^{C*} are both interior solutions, i.e. $\lambda = 0$, $\mu_1 = 0$, and $\mu_2 = 0$. K^{G*} and K^{C*} are derived from:

$$[A.76] \qquad \sum_{t=1}^{T} e^{-rt} \cdot \int_0^{a - b(N+1)(K^{G*} + K^{C*})} [a - b(N+1)(K^{G*} + K^{C*}) - c_t]\, g(c_t) dc_t = \frac{e^{-r}(1-e^{-rT})}{1-e^{-r}} \cdot \frac{\Theta^G}{T}, \text{ and}$$

[A.77] $\sum_{t=1}^{T} e^{-rt} \cdot \int_{a-b(N+1)K^{C*}}^{\infty} [c_t - a + b(N+1)K^{C*}]\, g(c_t)dc_t =$
$\sum_{t=1}^{T} e^{-rt} \cdot \int_{0}^{\infty} (c_t - c^C)\, g(c_t)dc_t - \frac{e^{-r}(1-e^{-rT})}{1-e^{-r}} \cdot \frac{\Theta^C - \Theta^G}{T}.$

Thus, this point is optimal iff

[A.78] $K^{G*} > 0$, i.e. $\frac{e^{-r}(1-e^{-rT})}{1-e^{-r}} \cdot \frac{\Theta^G}{T} < \sum_{t=1}^{T} e^{-rt} \cdot \int_{0}^{c^C+\Theta^C/T} [c^C + \Theta^C/T - c_t]\, g(c_t)dc_t$, and

[A.79] $K^{C*} > 0$, i.e. $c^C + \frac{\Theta^C}{T} < c_0 \cdot T / \frac{e^{-r}(1-e^{-rT})}{1-e^{-r}} + \frac{\Theta^G}{T}$.

Scenario (iii). $K^{G*} \neq 0$ and $K^{C*} = 0$, i.e. $\mu_1 = 0$. K^{G*} and μ_2 are solved from:

[A.80] $\sum_{t=1}^{T} e^{-rt} \cdot \int_{0}^{a-b(N+1)K^{G*}} [a - b(N+1)K^{G*} - c_t]\, g(c_t)dc_t = \frac{e^{-r}(1-e^{-rT})}{1-e^{-r}} \cdot \frac{\Theta^G}{T}$, and

[A.81] $\mu_2 = \frac{e^{-r}(1-e^{-rT})}{1-e^{-r}} \cdot \frac{\Theta^C - \Theta^G}{T} - \sum_{t=1}^{T} e^{-rt} \cdot \int_{0}^{\infty} (c_t - c^C)\, g(c_t)dc_t.$

Thus, this point is optimal iff $\mu_2 \geq 0$, i.e. $c^C + \frac{\Theta^C}{T} \geq c_0 \cdot T / \frac{e^{-r}(1-e^{-rT})}{1-e^{-r}} + \frac{\Theta^G}{T}$.

K^{G*} and K^{C*}, the optimal capacities of the *i*-th firm, may be either interior or corner solutions. That is, we have to examine whether the KKT conditions, given by [8.9], are satisfied simultaneously in each one of the three possible solutions (we do not analyze the trivial solution, i.e., $K^{G*} = 0$ and $K^{C*} = 0$).

Scenario (i). $K^{G*} = 0$ and $K^{C*} \neq 0$, i.e. $\mu_2 = 0$. K^{C*} and μ_1 are given by:

[A.82] $K^{C*} = \frac{a - c^C - \frac{\Theta^C}{T}}{b(N+1)}$, and

[A.83] $\mu_1 = \frac{e^{-r}(1-e^{-rT})}{1-e^{-r}} \cdot \frac{\Theta^G}{T} - \sum_{t=1}^{T} e^{-rt} \cdot \int_{0}^{c^C+\Theta^C/T} [c^C + \Theta^C/T - c_t]\, g(c_t)dc_t.$

Thus, this point is optimal if

[A.84] $K^{C*} \geq 0$, i.e.$a \geq c^C + \frac{\Theta^C}{T}$, and

[A.85] $\mu_1 \geq 0$, i.e., $0 \geq \sum_{t=1}^{T} e^{-rt} \cdot \left[\int_{0}^{c^C+\Theta^C/T} [c^C + \Theta^C/T - c_t]\, g(c_t)d - \frac{\Theta^G}{T}\right] \leq 0$

Scenario (ii). K^{G*} and K^{C*} are both interior solutions, i.e., $\mu_1 = 0$, and $\mu_2 = 0$.K^{G*} and K^{C*} are derived from:

[A.86] $\sum_{t=1}^{T} e^{-rt} \cdot \left[\int_{0}^{c_{K^{G*}+K^{C*}}} [c_{K^{G*}+K^{C*}} - c_t] \cdot g(c_t)dc_t - \frac{\Theta^G}{T}\right] = 0,$

[A.87] $\sum_{t=1}^{T} e^{-rt} \cdot \left[\int_{c_{K^{C*}}}^{\infty} \left[c_{K^{C*}} - c^C\right] g(c_t) dc_t + E(c_t) - c^C + \frac{\Theta^G}{T} - \frac{\Theta^C}{T}\right] = 0,$

Thus, this point is optimal if:

[A.88] $K^{G*} > 0$, i.e. $0 < \sum_{t=1}^{T} e^{-rt} \cdot \left[\int_0^{c^C + \Theta^C/T} [c^C + \Theta^C/T - c_t]\, g(c_t) dc_t - \frac{\Theta^G}{T}\right]$

[A.89] $K^{C*} > 0$, i.e. $c^C + \frac{\Theta^C}{T} < E(c_t) + \frac{\Theta^G}{T}$.

Scenario (iii). $K^{G*} \neq 0$ and $K^{C*} = 0$, i.e. $\mu_1 = 0$. K^{G*} and μ_2 are solved from:

[A.90] $\sum_{t=1}^{T} e^{-rt} \cdot \left[\int_0^{c_{K^{G*}}} \left[c_{K^{G*}} - c_t\right] g(c_t) dc_t - \frac{\Theta^G}{T}\right] = 0$, and

[A.91] $\mu_2 = \frac{e^{-r}(1-e^{-rT})}{1-e^{-r}} \cdot \frac{\Theta^C - \Theta^G}{T} - \sum_{t=1}^{T} e^{-rt} \cdot \int_0^{\infty} (c_t - c^C)\, g(c_t) dc_t.$

Thus, this point is optimal if f$\mu_2 \geq 0$, i.e. $c^C + \frac{\Theta^C}{T} \geq E(c_t) + \frac{\Theta^G}{T}$

Proof of Proposition 8-2

Following Lee et al. (2010), we have that the value $\int_0^x g(c_t)(x - c_t) dc_t$ increases with the volatility, σ_{c_t}.

For a given value of $\sum_{t=1}^{T} e^{-rt} \cdot \int_0^{\infty} (c_t - c^C)\, g(c_t) dc_t - \frac{e^{-r}(1-e^{-rT})}{1-e^{-r}} \cdot \frac{\Theta^C - \Theta^G}{T}$, if σ_{c_t} increases, then $a - b(N+1)K^{C*}$ increases to satisfy equation [8.11], and therefore K^{C*} decreases.

If σ_{c_t} increases and K^{C*}decreases, then the LHS of [8.12] increases; therefore, K_i^Gincreases to satisfy [8.12] ■

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Hebrew Abstract

תקציר

מאז שנות ה-80 של המאה הקודמת, מדינות רבות ארגנו מחדש את משקי החשמל שלהן ועברו ממבנה של מונופול מפוקח למבנה שוק תחרותי, בו החלטות על השקעה בתחנות כוח, יצור ומכירת חשמל מתקבלות ע״י גורמים פרטיים. ההחלטה של יצרנים על השקעה בתחנות כוח מבוססת על הערכה של תוחלת הרווח הצפויה מהשקעה זו בעתיד. לכן, המעבר לשוק חשמל תחרותי חושף את יצרני החשמל לסיכונים אשר בשוק מונופוליסטי הועברו באמצעות התעריף המפוקח לצרכנים. בעשורים האחרונים התפתח מאוד גם השימוש בגז טבעי בשווקי החשמל בעולם, בין השאר כתוצאה מהתקדמות טכנולוגית בהפקת הגז ממאגרים שנחשבו בעבר לא כדאיים כלכלית, כגון פצלי גז. מתקני יצור חשמל מבוססי גז טבעי מתאפיינים במיעוט פליטות ובעלויות הקמה נמוכות משמעותית לעומת מתקני יצור חשמל המשתמשים בפחם. בנוסף לכך, מתקני יצור חשמל המשתמשים בגז מאפשרים, בין היתר, גמישות בהפעלת סך ייצור החשמל במשק (גמישות העמסה), ולכן הם מהווים מענה משלים לכניסה הגוברת של ייצור חשמל באמצעות אנרגיות מתחדשות. כתוצאה מכך, מרבית תחנות הכוח המוקמות היום בעולם מבוססות על גז טבעי. לצד יתרונות אלה, השימוש בגז טבעי לייצור חשמל חושף את היצרנים לסיכון: מחיר הגז מהווה כ 80% מעלות הייצור המשתנה והוא מאופיין בתנודתיות (volatility) גבוהה משמעותית לעומת התנודתיות במחירי דלקים אחרים.

השפעת חוסר הוודאות של מחירי הגז הטבעי על ההשקעה בהקמת תחנות כוח לא קיבלה עד כה ביטוי משמעותי במחקר האקדמי, על אף חשיבותה. המחקר העיקרי בתחום זה נעשה בשנות התשעים של המאה העשרים ע״י Dixit and Pindyck (1994) במסגרת מחקרם על אופציות ריאליות (Real Options). אולם, מחקר זה מניח שוק תחרותי שבו ההחלטות של יצרן בודד אינן משפיעות על השוק. הנחה זו איננה מתארת באופן מיטבי משקי חשמל, המתאפיינים במבנה אוליגופוליסטי של מספר יצרנים מוגבל.

מחקר זה מבוסס על המודלים שפותחו על ידי Tishler, Milstein and Woo (2008) ועל ידי Milstein, Tishler and Woo (2012) לניתוח השקעות במשקי חשמל תחרותיים. מודל בעבודה זו מרחיב את המודלים שקדמו לו בכך שהוא כולל גם התייחסות לאי וודאות במחירי הדלקים המשמשים לייצור חשמל. המודל הבסיסי בעבודה זו (פרק 5) מניח תהליך דו שלבי. בשלב הראשון היצרנים מחליטים על ההשקעה בקיבולת לייצור חשמל (capacity), בכפוף להערכת תוחלת הרווח הצפויה מהשקעה זו ולהתפלגות מחיר הגז הטבעי. בשלב השני, כאשר מחיר הגז הטבעי ידוע

לכול, נקבעים הכמות המיוצרת ומחיר החשמל לצרכנים. השלב השני חוזר על עצמו כל יום במשך כול תקופת ההפעלה של הקיבולת. בשונה מההנחה המקובלת, המודל בעבודה זו מראה כי ההשקעה בתחנות כוח המשתמשות בגז טבעי צפויה לגדול ככל שהתנודתיות, המהווה מדד טוב לאי וודאות, של מחיר הגז גבוהה יותר. כלומר, יצרני חשמל יבחרו להקים קיבולת ייצור גדולה יותר, ככל שאי הוודאות גדלה. תוצאה זו מתקבלת עקב האופי הא-סימטרי של התפלגות מחיר הגז בפועל בשווקים שונים בעולם (התפלגות לוג-נורמלית), הנותנת סיכוי גבוה יותר לקיום מחירי גז נמוכים ככל שהתנודתיות עולה. כתוצאה מכך, תנודתיות גבוהה יותר במחיר הגז תביא לתוחלת רווח גדולה יותר ליצרנים ולעודף צרכן גבוה יותר.

למרות האפקט החיובי של תנודתיות מחיר הגז הטבעי, יצרנים במשק החשמל עשויים לרצות לגדר את הסיכון של מחירי גז גבוהים כדי להבטיח את יכולתם לשרת את החוב. לכן, בחנו במחקר זה שיטות פיננסיות ופיסיות שונות לגידור הסיכון של מחיר הדלק. ראשית, בחנו (פרק 6) את השימוש באופציות לגידור מחיר הגז. מצאנו שהשימוש באופציות יתרום לעליה בעודף הצרכן, אולם למרות זאת, האסטרטגיה המיטבית של היצרן היא לא לגדר את הסיכון באמצעות אופציות, משום שעלות הגידור גבוהה מתוחלת הרווח הצפויה ליצרן מגידור זה. שנית, בחנו (פרק 7) את האפשרות של שימוש בתחנות דו-דלקיות לגידור מחיר הגז (כלומר, אפשרות מעבר לייצור חשמל על ידי דלק חליפי כאשר מחיר הגז גבוה). מצאנו כי השימוש בתחנות דו-דלקיות יביא להגדלת ההשקעה בקיבולת רק כאשר מחיר הדלק הדואלי נמוך או כאשר חוסר הוודאות של מחירי הגז גבוה. השימוש בתחנה דו-דלקית מגדר את הסיכון של מחיר גז גבוה ולכן מועיל הן ליצרנים והן לצרכנים. עם זאת, היצרנים נושאים בעלות ההשקעה הנוספת הנדרשת כדי לאפשר יכולת זו, ולכן תוחלת הרווח שלהם עשויה, לעתים, לקטון. כמו כן, כאשר מחיר הדלק הדואלי גבוה, הקמת תחנה דו-דלקית תביא להשקעה נמוכה יותר בקיבולת, וכתוצאה מכך יקטן עודף הצרכן.

לבסוף, חקרנו את השימוש בתמהיל טכנולוגיות לגידור סיכון הדלק (קרי, חלק מהקיבולת לייצור חשמל מבוסס על שימוש בגז טבעי וחלק אחר מבוסס על שימוש בפחם שמחירו מתאפיין בתנודתיות נמוכה מזו של מחיר הגז הטבעי). מצאנו כי בשונה משימוש בתחנות דו-דלקיות, שילוב תחנות פחמיות בתמהיל התחנות אמנם מגדר את הסיכון של מחירי גז גבוהים אך גם מגביל את הפוטנציאל לרווח גבוה כאשר מחיר הגז יורד. כמו כן, מצאנו כי החלק האופטימלי של הקיבולת המבוסס על גז טבעי בתמהיל הטכנולוגיות האפשרי (גז ופחם) עולה ככל שתנודתיות מחיר הגז גבוהה יותר. מהמחקר עולה גם, כי עודף הצרכן אינו תלוי בתמהיל תחנות הכוח, משום שסך הקיבולת המוקמת נותר קבוע ואין שינוי בכמות האנרגיה המיוצרת ובמחיר החשמל.

תוצאות המודלים שפותחו בעבודה זו מודגמות באמצעות דוגמאות מספריות המשתמשות בנתונים ומבנה משק חשמל המאפיינים את שווקי החשמל התחרותיים בטקסס ובקליפורניה.

לסיכום, עבודה זו תורמת לספרות האקדמית והמקצועית בכך שהיא מוסיפה למודלים הקיימים את היכולת להעריך את המשמעות של אי וודאות במחיר הגז הטבעי על הקיבולת, המחיר וכמות ייצור החשמל במשקי חשמל תחרותיים. כמו כן, המחקר מקנה כלים מעשיים לחברות ולקובעי מדיניות כיצד לגדר באופן מיטבי את מחיר הדלקים המיועדים לשימוש בתחנות הכוח.

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