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Intermittently renewable energy, optimal capacity mix and prices in a deregulated electricity market ☆

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ABSTRACT

This paper assesses the effect of intermittently renewable energy on generation capacity mix and market prices. We consider two generating technologies: (1) conventional fossil-fueled technology such as combined cycle gas turbine (CCGT), and (2) sunshine-dependent renewable technology such as photovoltaic cells (PV). In the first stage of the model (game), when only the probability distribution functions of future daily electricity demand and sunshine are known, producers maximize their expected profits by determining the CCGT and PV capacity to be constructed. In the second stage, once daily demand and sunshine conditions become known, each producer selects the daily production by each technology, taking the capacities of both technologies as given, and subject to the availability of the PV capacity, which can be used only if the sun is shining. Using real-world data for Israel, we confirm that the introduction of PV technology amplifies price volatility. A large reduction in PV capacity cost increases PV adoption but may also raise the average price. Thus, when considering the promotion of renewable energy to reduce CO_2 emissions, regulators should assess the behavior of the electricity market, particularly with respect to characteristics of renewable technologies and demand and supply uncertainties.

1. Introduction

Besides nuclear energy expansion, commonly accepted remedies for the problem of global warming due to greenhouse gases (GHG), which will likely dominate public policy debates in the coming decade (Weyant et al., 2006; Tol, 2006; Lior, 2010; Cansino et al., 2010), include increased conservation and renewable energy to displace the use of fossil fuels (Trainer, 2010; Lior, 2010; Traber and Kemfert, 2010). Renewable energy is becoming an ever-increasing feature of the landscape worldwide. For instance, "[2009] was a record-setting year for wind energy in the IEA Wind member countries, which installed more than 20 gigawatts (GW) of new wind capacity. This growth led to a total of 111 GW of wind generating capacity, with more than 2 GW operating offshore" (IEA, 2010a, p.2). In 2008, renewable energy also met 7.3% of Germany's primary energy consumption, a figure that is predicted to increase to 33% by 2020 (Burgermeister, 2009). "It's ambitious, but Germany can be running on renewable energy by 2050 if there is the political will", said David Wortmann, Director of Renewable Energy and Resources at Germany Trade and Invest, a government body supporting the country's renewable energy sector (Burgermeister, 2009).

However, recent research on nuclear energy (Kessides, 2010; NEA, 2010; Lior, 2010), carbon capture and storage (CCS) (MIT, 2007; IEA, 2010b) and incentives to promote green electricity (Cansino et al., 2010; Badcock and Lenzen, 2010) suggests that the road to a "green world" is not fully paved and the potentials and limits of renewable energy are insufficiently explored and understood (Trainer, 2010; Lior, 2010). It also suggests that recent European policies to reduce GHG emissions[1] and conform to the Kyoto Protocol will likely raise electricity prices substantially, unless new approaches to electricity generation are adopted (Linares et al., 2006; Reedman et al., 2006; Odenberger and Johnsson, 2007; Martinsen et al., 2007; Cansino et al., 2010).

This paper offers a formal model to aid regulatory understanding of the relationship between renewable energy, optimal generation mix, and electricity price level and volatility. In particular, it demonstrates that weather dependence of renewable energy sources (using the example of photovoltaic cells) and the fact that electricity power cannot be economically stored and the

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[1] The quantities of CO_2 emissions by technology are detailed in Lise and Kruseman (2008) and Kessides (2010). The cost of reducing GHG in the electricity sector depends on the country's existing and future mix of generation technologies (Bataille et al., 2007; Tishler et al., 2007). Samuelson (2007) discusses the practical difficulties of mitigating GHG emissions.

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demand side cannot be sufficiently managed (Traber and Kemfert, 2010) can cause price spikes and increase the average price and price volatility, particularly when PV adoption rises due to its declining cost.[2] Furthermore, these price effects worsen with the introduction of CO_2 taxes, a policy that aims to reduce emissions, as required by the Kyoto protocol (Cansino et al., 2010; Badcock and Lenzen, 2010). To be fair, enforcing high electricity prices via GHG taxes is likely to boost R&D expenditure by governments and private firms on productive, safe and new technologies which will, eventually, bring about "cleaner" and more environment-friendly electricity generation.

To simplify the exposition, our model only employs combined cycle gas turbine (CCGT) and PV plants. However, its results equally apply to other fossil as well as weather-dependent renewable energy sources such as wind, solar-thermal technologies, and sea waves. In particular, more efficient electricity production by PV technology will enhance the following effects:

- In the short term, when most of the generation capacity is given, it will shift production away from CO_2-intensive (fossil) technologies to PV technology.
- In the mid and long term, optimal capacity mix will shift new capacity construction away from CO_2-intensive technologies to PV technology and, possibly, cause early retirement of CO_2-intensive technologies.
- An increase in the share of electricity production by PV technology will raise the equilibrium electricity price during periods in which weather conditions limit its use.
- Since electricity demand is very "inelastic", particularly in the short run, electricity prices will spike substantially during these periods, and will likely raise the average price and price volatility.

This paper contributes to the literature by presenting an analytical model of endogenous investments and operations in an electricity market with CCGT and PV technology under demand and supply uncertainties.[3] Formally, in the first stage of the game, when only the probability distribution functions of future daily electricity demands and weather conditions are known, profit-seeking producers maximize their expected profits by determining the amount of generation capacity to be constructed for each technology. In the second stage, after daily demand and sunshine-determined PV availability become known, each producer selects its daily electricity production, thereby determining the equilibrium market prices. Like many other studies of the electricity sector, we employ the Cournot conjecture to determine equilibrium quantities and prices in the second stage of the game, where electricity is sold simultaneously by all producers to meet market demand (Carpio and Pereira, 2007; Borenstein and Bushnell, 1999; Green, 1996, 2004; Newbery, 1998; Tishler and Woo, 2006; Puller, 2007; Murphy and Smeers, 2005, 2007; Tishler et al., 2008; Bushnell et al., 2008). We show that the optimal solution is very sensitive to PV's sunshine-dependent availability and capital cost. These theoretical properties of the model are illustrated using data for the Israeli electricity market.[4]

[2] Substantial price volatility due to sudden and unexpected change in wind generation is reported by ERCOT in Texas (Hardy and Nelson, 2010).

[3] Although the analysis becomes more complicated, it is straightforward to demonstrate the nature of the solution is unchanged by adding more generating technologies (Milstein and Tishler, 2009).

[4] Tishler et al. (2008) present recent data on four major electricity markets in the USA (New England; California; PJM—Pennsylvania, New Jersey and Maryland; and ERCOT, Texas) demonstrating that the characteristics of the distribution of electricity prices over time in these markets and in Israel are very similar. Thus, the results in this paper likely apply to those, and other, markets.

2. Model

Consider two types of generating technologies: (1) CCGT, to be denoted **G**, which exhibits "low" capacity cost and "high" variable cost; and (2) PV, to be denoted **S**, with high capacity cost and zero variable cost.[5] The oligopoly market consists of N identical firms, each employing both technologies. Each firm builds generating capacity and then uses it to generate and sell electricity on each day of an operation horizon of T days (e.g., $T=365$ for a 1-year horizon).[6] Let P_t and Q_t denote the electricity price and output on day t. Following Wolfram (1999) and Tishler et al. (2008), daily electricity demand is

$$P_t = a - bQ_t + \varepsilon_t \tag{1}$$

where $Q_t = \sum_{i=1}^{N}(Q_{it}^G + Q_{it}^S)$ and Q_{it}^G and Q_{it}^S denote the CCGT and PV production on day t of the i-th firm. The parameters $a>0$ and $b>0$ are assumed to be known constants. In Eq. (1), ε_t is a random variable accounting for the effect of a random demand factor such as temperature. ε_t is revealed to the electricity producers on day t and the price is determined each day according to the Cournot conjecture.[7] Only $f(\varepsilon_t)$, the (probability) density function of ε_t, and the probability function of daily sunshine are known to the firms when they choose their capacity.

Following Murphy and Smeers (2005, 2007) and Milstein and Tishler (2009), the annual production cost of the i-th firm employing technology **G** (technology **S**) and a generator of K_i^G (K_i^S) MW of capacity is

$$C_i(K_i^G, Q_i^G) = \theta^G K_i^G + c^G Q_i^G \tag{2a}$$

$$C_i(K_i^S, Q_i^S) = \theta^S K_i^S + c^S Q_i^S \tag{2b}$$

where $Q_i^G = \sum_{t=1}^{T} Q_{it}^G$ and $Q_i^S = \sum_{t=1}^{T} Q_{it}^S$ denote the annual CCGT and PV production by firm i, respectively. Capacity cost is US\$ θ^G (θ^S) per MW-year and variable (marginal) cost is US\$ c^G (c^S) per MWH for technology **G** (technology **S**). By assumption, technology **G** is more expensive in operations, $c^G \gg c^S \cong 0$, and technology **S** is more expensive in capacity, $\theta^S > \theta^G$. The parameters c^G, c^S, θ^G and θ^S are assumed to be known constants.

The availability of PV capacity on day t, $t=1,\ldots,T$, is conditional on whether the sun is shining. We suppose that the sun is shining with probability ρ. If the sun is shining on day t, all of PV capacity is available on that day; otherwise the available PV capacity is zero. For expositional simplicity, we assume that the availability of the sun and ε_t are independent.[8] This assumption reflects our contention that demand is mainly driven by temperature, much less so by daily cloudiness. Finally, we assume that $E(\varepsilon_t)=0$, $Var(\varepsilon_t)=\sigma^2$ and $c^S < a+\varepsilon_t$.[9]

The decision process of this two-stage game is as follows:

[5] Neither of these two technologies dominates the other. See Chao (1983) and Milstein and Tishler (2009) on this issue and the general use of the concept "merit order" in electricity markets.

[6] Electricity demand can be defined for any length of time. It is straightforward, for example, to solve the model for 8760 hours or 17520 half-hours of the year. The model assumes that consumers are informed about electricity prices and can respond, at least to some extent, to electricity price changes.

[7] Puller (2007) shows that the conduct of the firms in the restructured electricity market in California during April 1998 until late 2000 is consistent with a Cournot pricing game. Bushnell et al. (2008) find that a Cournot-competition predicted equilibrium prices are good approximations for actual electricity prices during the summer of 1999 in three US markets.

[8] The nature of the results is unchanged if these two variables are correlated. Price volatility tends to be higher if they are positively correlated.

[9] If $E(\varepsilon_t)=\mu\neq 0$, we add μ to the constant a in expression (1), thus setting $E(\varepsilon_t)=0$.

Stage 1: Each of the N firms decides on its capacity investment, K_i^G and K_i^S, to maximize its expected profits over T days, taking the capacities of the other $N-1$ firms and the probability functions of ε_t and daily sunshine as given.
Stage 2: Once the firms know ε_t and the sunshine condition on day t, each firm decides how much electricity to produce (and sell) to maximize its daily operating profit. The firm's decision is based on the Cournot conjecture, treating the quantity produced by the other $N-1$ firms and the capacity of all N firms as given. This stage is repeated T (independent) times.

The game is solved recursively using backward induction. The daily electricity production of each firm is found by solving the second stage of the game. The optimal second-stage solutions (the reaction functions) are then used to determine the expected profit-maximizing generation capacities in the first stage.

Formally, the objective of the i-th firm in stage 2 is to maximize its operating profits, π_{it}, conditional on ε_t, appearance of the sun, $K_i^G$and $K_i^S(i=1,...,N)$, Q_{kt}^G and Q_{kt}^S $(k=1,...,N; k\neq i)$. When the sun is shining, the maximization problem of firm i on day t is

$$\max_{Q_{it}^G,Q_{it}^S} \quad \pi_{it}=(P_t-c^G)Q_{it}^G+(P_t-c^S)Q_{it}^S$$
$$s.t. \qquad Q_{it}^G\leq K_i^G, \quad Q_{it}^S\leq K_i^S, \quad Q_{it}^G,Q_{it}^S\geq 0, \quad i=1,\ldots,N \tag{3}$$

When there is no sun, the maximization problem of firm i on day t is

$$\max_{Q_{it}^G,Q_{it}^S} \quad \pi_{it}=(P_t-c^G)Q_{it}^G$$
$$s.t. \quad Q_{it}^G\leq K_i^G, \quad Q_{it}^G\geq 0, \quad i=1,\ldots,N \tag{4}$$

Table 1
Daily averages and maximal values of hourly electricity use in Israel during 2009 (1000 MWH).

	Average hourly use	Maximal hourly use
Mean	6.08	7.36
Median	5.97	7.28
Sample standard deviation	0.84	1.05
Minimum	4.29	5.33
Maximum	8.04	9.88

The solution of Eq. (3) is given in Milstein and Tishler (2009) and the solution of Eq. (4) is given in Tishler et al. (2008). To determine optimal capacities, the i-th firm uses the second-stage reaction functions to solve the stage 1 expected profit maximization problem

$$\max_{K_i^G,K_i^S} \quad \rho E\left[\sum_{t=1}^{T}(\pi_{it}|K_i^G,K_i^S)\right]+(1-\rho)E\left[\sum_{t=1}^{T}(\pi_{it}|K_i^G)\right]-\theta^G K_i^G-\theta^S K_i^S. \tag{5}$$

There is no closed form solution of problem (5) and the optimal capacities, $K_i^{G^*}$ and $K_i^{S^*}$, are obtained by numerical methods.

3. Application to real-world data

To illustrate its real-world relevance, we apply our model to Israeli data. Table 1 lists descriptive statistics of the hourly electricity use in Israel during 2009 and Fig. 1 presents the histogram of these data (IEC, 2010). The data in Fig. 1 and Table 1 show that the distribution of the hourly electricity use in 2009 is close to symmetrical, with most of the mass around the mean.

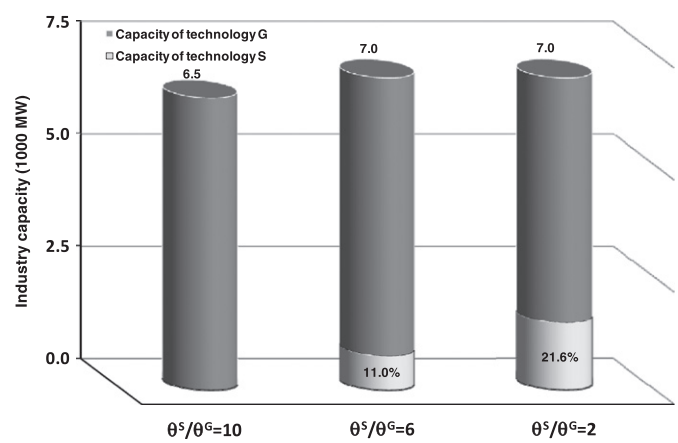

Fig. 2. Industry capacity.

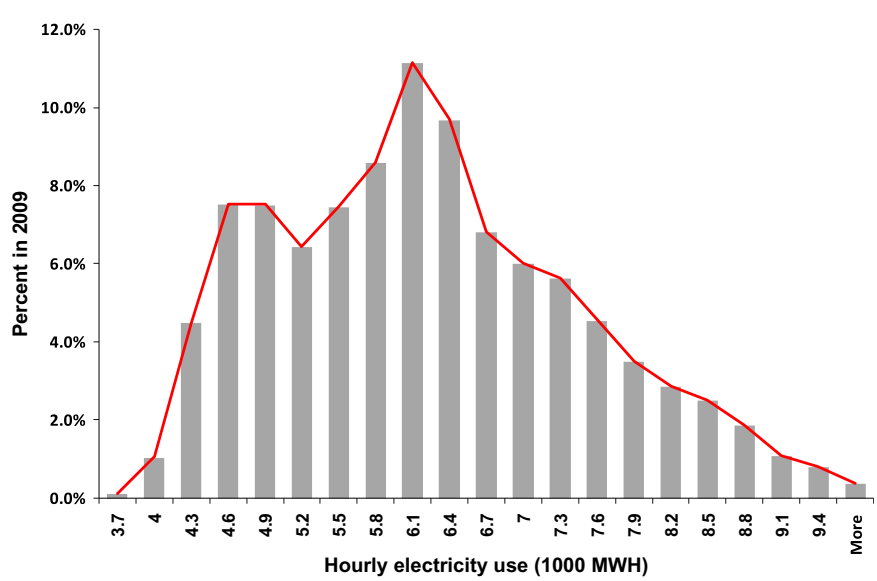

Fig. 1. Histogram of hourly electricity use in 2009.

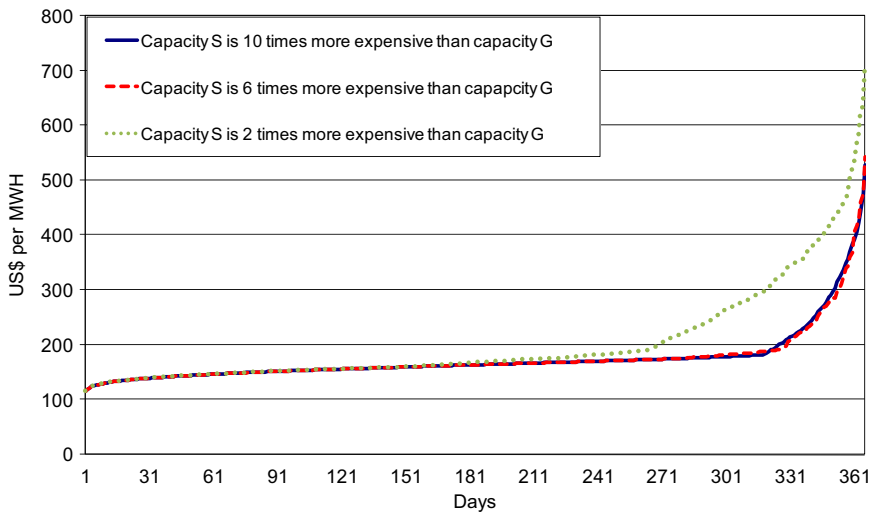

Fig. 3. Price distribution over the year.

Computation of the optimal capacities is based on estimates of the demand parameters, a and b, the cost parameters, θ^G, θ^S, c^G, and c^S, the parameters of the probability function $f(\varepsilon_t)$ and on ρ. Using the average generation price in 2009 (66.4 \$/MWH) and a (short-run) price elasticity of -0.05 for the daily demand function for electricity,[10] these estimates are as follows (Tishler et al., 2008):[11] $a=1394.4$, $b=218.4$, $\theta^G/T=223.0$, $c^G=40$, and $c^S=0$.

To illustrate the properties of the equilibrium solution of the model, we consider three PV to CCGT capacity cost ratios: (1) $\theta^S/\theta^G=10$, (2) $\theta^S/\theta^G=6$, and (3) $\theta^S/\theta^G=2$.[12] The first stage of the game is solved under the assumption that $f(\varepsilon_t)$ follows the uniform distribution, $f(\varepsilon_t)=1/(\beta-\alpha)$, with $\alpha=-317$and $\beta=317$.[13] We also assume $\rho=0.6$[14] and $N=10$.[15]

Fig. 2 presents the industry's optimal capacity as a function of θ^S/θ^G. It shows that producers will not build PV capacity at the prevailing (very high) capacity cost of the PV technology, mirroring the reality reported in Trainer (2010), Lior (2010), and Badcock and Lenzen (2010). The share of PV capacity in the industry's total capacity increases when PV capacity cost decreases.[16] Uncertainty in daily PV capacity, however, reduces its profitability. Hence, a large PV capacity cost reduction only leads to a moderate increase in PV adoption. As shown in Fig. 2, PV capacity is about 22% of total capacity when PV capacity cost is reduced by 80%.

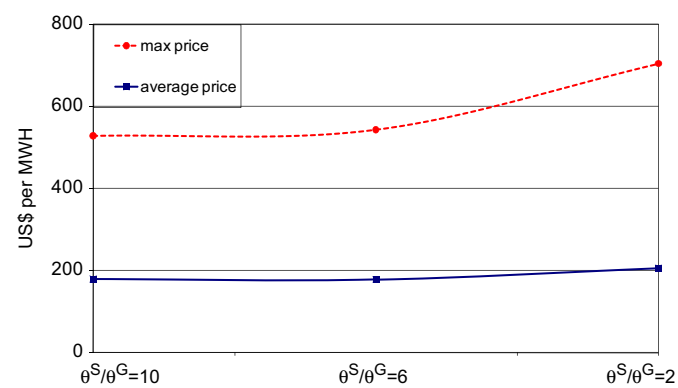

Fig. 4. Average and maximal price.

Milstein and Tishler (2009) show that the frequency of price spikes does not depend on the fixed cost of the base technology (PV in our model) when its capacity is always available ($\rho=1$). This result does not hold when $\rho<1$. Fig. 3 presents the distribution of daily equilibrium electricity prices in the year.

Equilibrium prices are stable when production is below full capacity and start to rise at an increasing rate once full capacity is reached. Full capacity is reached *earlier*, the *higher* is the share of PV in total capacity, which occurs due to lower PV capacity cost. In our example, when PV capacity is zero because the sun is not shining, the CCGT technology reaches full capacity for 17, 35 and 96 days of the year when $\theta^S/\theta^G=10$, $\theta^S/\theta^G=6$ and $\theta^S/\theta^G=2$, respectively.[17] Moreover, full capacity is reached on the 318th day of the year when $\theta^S/\theta^G=10$ and on the 266th day when $\theta^S/\theta^G=2$. Thus, price spikes are larger and more frequent under rising PV adoption due to declining PV capacity cost.

Fig. 4 presents the average and maximal electricity prices for $\theta^S/\theta^G=10$, $\theta^S/\theta^G=6$, and $\theta^S/\theta^G=2$. The average equilibrium prices increase from 179 \$/MWH when $\theta^S/\theta^G=10$ to 206 \$/MWH when $\theta^S/\theta^G=2$. The maximal price increases from 528 \$/MWH when

[10] The nature of the results of this study does not change when price elasticity is -0.1 or -0.25.

[11] See Khatib (2010) and Lior (2010) and references therein for the costs of electricity generation by various technologies.

[12] The first case, where the PV capacity cost is 10 times that of the CCGT capacity cost, reflects the current ratio in the Israeli market (Lior, 2010 and Trainer, 2010). The latter two cases represent technology improvements.

[13] Though the normal distribution seems to be a more reasonable approximation (see Fig. 1), the uniform distribution is simpler to use in our case (a similar assumption is made, for example, in Wang et al. (2007)). Tishler et al. (2008) show that employing the empirical, a uniform, or a normal distribution yields almost identical optimal capacity.

[14] This value seems to be realistic for Israel: nights constitute about one third of the year and the sun may appear partially or not at all during 5–15% of the year—mostly, but not only, during the winter.

[15] Daily prices are somewhat lower (higher) when N increases (decreases), but the nature of the results does not change for larger (smaller) N.

[16] PV is the most-run technology since its marginal production cost is zero. The industry's total capacity is lower in a competitive market than under regulation due to the price spikes, which "shave" demand during peak hours, thus reducing the need for capacity during peak hours (Tishler et al., 2008).

[17] Price spikes may not occur if the value of the random variable, ε_t, is sufficiently small. For example, technology **G** reaches full capacity on 96 days when $\theta^S/\theta^G=2$. On six of these days we do not observe price spikes, due to small realizations of ε_t.

Table 2
Maximal electricity prices as a function of θ^S/θ^G and ρ.

ρ	$\theta^S/\theta^G=10$	$\theta^S/\theta^G=6$	$\theta^S/\theta^G=2$
0.6	527.9	542.9	704.1
0.7	527.9	583.8	743.8
0.8	527.9	652.6	826.0
0.9	506.4	689.7	906.0
0.99	520.3	895.9	1275.2

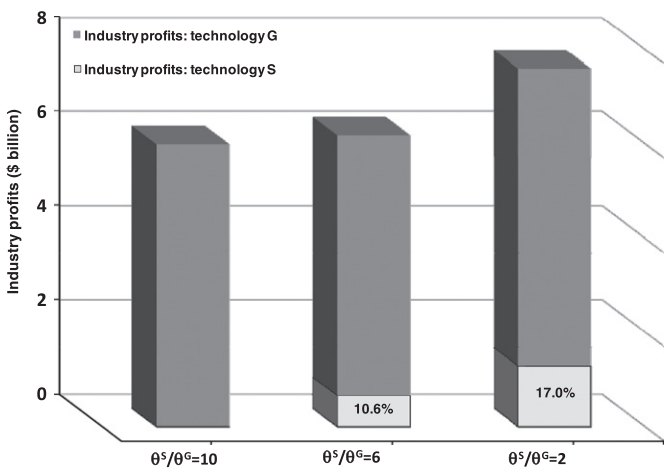

Fig. 5. Industry profits.

$\theta^S/\theta^G=10$ to 704 \$/MWH when $\theta^S/\theta^G=2$. Thus, the larger PV capacity share yields higher electricity price spikes on days without sun, when all the demand must be met by CCGT. Very high price spikes together with very low price elasticity give producers some monopoly power, potentially raising the average electricity price over the year. This phenomenon does not happen when $\rho=1$ (the sun is always shining), and the average electricity price decreases when PV capacity cost declines in this case (Milstein and Tishler, 2009).

Table 2 presents the maximal daily electricity prices as a function of θ^S/θ^G for different values of ρ. A higher value of ρ implies a higher share of PV capacity in total capacity which, in turn, implies higher electricity price spikes on days without sunshine, as all the demand must be met by CCGT capacity installed. When the capacity cost of PV is large, producers build PV capacity only when the sun shines on a sufficient number of days. This happens when $\theta^S/\theta^G=10$ and $\rho=0.9$ or higher (the optimal PV capacity is zero when $\theta^S/\theta^G=10$ and $\rho<0.9$).[18]

Do Fig. 4 and Table 2 mean that R&D improvements or government subsidies to PV technology are not socially desirable? Not necessarily. Fig. 5 shows that the industry's profit increases when θ^S/θ^Gdecreases. One reason for the profit increase is lower total generation cost. Another reason is higher oligopoly profits due to the low price elasticity of electricity demand, which enables producers to gain more on rising market prices than they lose on falling market prices.

[18] At the point at which producers start to build some PV capacity, which is $\theta^S/\theta^G=10$and $\rho=0.9$ in our case, total capacity increases, PV capacity is very low, CCGT capacity is still "large", and price spikes may occur on days on which ε_t is "large" (rather than on days on which the sun is not shining). Consequently, the maximal electricity price may decline in this situation relative to the maximal price when $\rho<0.9$ (see the first column of Table 2).

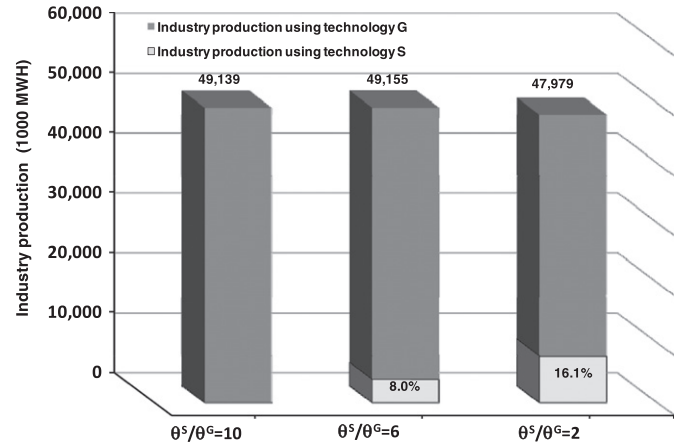

Fig. 6. Industry production.

Fig. 6 shows that the industry's production tends to decline as PV capacity cost falls. This mirrors rising PV adoption due to declining PV capacity cost, which in turn raises the average market prices, thus reducing market demand. Finally, the industry's electricity production in a competitive market is lower in comparison to production under market regulation (about 53 million MWH in 2009; see IEC, 2010).

4. Conclusion

This paper analyzes the relationship between intermittently renewable energy and optimal endogenous generating capacity mix, energy production by technology, and market prices in a Cournot market with CCGT and PV generation. The solution to a two-stage game shows that rising adoption of PV due to declining PV capacity cost can increase the average market price and price volatility. This result is confirmed by an application to real-world data for the Israeli electricity sector. It arises because market prices spike to balance the price-inelastic demand and CCGT capacity installed when PV output disrupts due to a lack of sunshine.

The paper highlights that tight generating capacity and frequent electricity price spikes in competitive electricity markets are due not only to demand variability over time (day, season and year), the high cost of constructing capacity and the long lead time required to add new capacity, but also to supply uncertainty, an inevitable outcome in markets with substantial renewable generation capacity (Hardy and Nelson, 2010; Trainer, 2010; Lior, 2010).

To be sure, an independent system operator may mitigate price spikes by maintaining capacity reserves that will not be part of the daily market operations (Tishler et al., 2008). However, the analysis of this paper underscores the fact that efficient use of renewable capacity requires an integrated approach to the management of electricity markets, one that accounts for modern and properly distributed T&D infrastructure, balancing generation, smart grids, and implementation of appropriate financial and other incentive systems (Lior, 2010; Hardy and Nelson 2010 and references therein).

Finally, this paper accentuates the importance of regulators understanding the behavior of the electricity market when considering the promotion of renewable energy for the purpose of reducing CO_2 emissions, particularly with respect to the characteristics of renewable technologies, demand and supply uncertainties, and market structure. Absent such an understanding, successful promotion that results in a generation mix dominated by

intermittent capacities can have unintended consequences, including rising average market price level and worsening price volatility.

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