Market Power and Technological Bias: The Case of Electricity Generation

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August 2005

CWPE 0532 *and* EPRG 01

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Market Power and Technological Bias: The Case of Electricity Generation

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May 13, 2005

Abstract

It is difficult to eliminate all market power in electricity markets and it is therefore frequently suggested that some market power should be tolerated: extra revenues contribute to fixed cost recovery, facilitate investment, and increase security of supply. This suggestion implicitly assumes all generation technologies benefit equally from market power. We assess a mixture of conventional and intermittent generation, e.g. coal plants and wind power. If all output is sold in the spot market, then intermittent generation benefits less from market power than conventional generation. Forward contracts or option contracts reduce the level of market power but the bias against intermittent generators persists.

JEL: D42, D43, L12, L13, Q42

Keywords: Market Power, Technology Choice, Electricity markets, Intermittent Output, Forward and Option Contracting

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1 Introduction

Renewable energy technologies are playing an increasingly important role in the portfolio mix of electricity generation. However, the intermittent nature of output from wind turbines and solar panels is frequently discussed as a potential obstacle to larger scale application of these technologies. Contributions of 10-20% of electrical energy from individual intermittent technologies create little technical difficulties and additional system costs. With greater contributions from intermittent technologies, stress to the electricity system could arise during periods when low output from intermittent generation coincide with high electricity demand. Old power stations would need to be retained or low capital cost new power stations built to provide electricity for these periods. Prices during these periods would be high because of high marginal costs of such generation or the scarcity value of generation capacity. Intermittent generation with high market shares would not benefit from these high price periods as they occur precisely when intermittent output is low. The average price received by intermittent generation is therefore lower than the average price received by the remaining technologies. This intermittency discount is not a market failure but simply reflects the value of electricity provided by different technologies. Building on this base case the paper assesses the impact of monopolist and strategic behaviour of conventional generation companies on the revenues for intermittent generation.

Market power of generation companies in wholesale electricity markets can easily arise because of low demand elasticity, regional separation of markets due to transmission constraints and extremely high costs to store electricity (Schmalensee and Golub 1984). Regulators and competition authorities are concerned by the presence of excessive exercise of market power but have difficulty in monitoring and mitigating price deviations below 10-20% over marginal cost. While the level of market power is frequently argued to be significant (Borenstein, Bushnel and Wolak 2002), these deviations are increasingly accepted, particularly as they might result in additional incentives to invest in generation capacity - a major concern of policy makers.

This paper looks in more detail at the implication of market power in short-term markets where there is intermittent output by fringe generators. For this paper we will assume that these intermittent fringe generators are wind turbines. In a Cournot model the exercise of market power by conventional (thermal) generation companies is increasing with the demand for their output. That implies that market power exercise is high when wind output is low and low when wind output is high. Wind generators therefore benefit less from the exercise of market power than conventional generators. Frequently supply function models are used to represent strategic behaviour in electricity spot markets. They predict a disproportional increase in the exercise of market power with demand increase - therefore our linear approximation in the Cournot model represents a lower bound.

Long-term energy contracts are the main mechanism to reduce market power in spot markets (Green 1999). The less output generators sell at spot prices, the lower their incentive to increase spot prices by increasing their bids or by withholding output. We show that under this mechanism the bias against returns to intermittent generation is also present as in the competitive case. However in this case, the non-proportionate share of market power margins may not be in the interest of an industry which is hoping to encourage renewable generation. We model endogenous and exogenous long-term contracting, assuming that the strategic (conventional) generators will sell a proportion of their output on long-term contracts. Then they will have to buy back some energy at times of high wind output. If generators act as strategic buyers, then they will offer lower prices, perhaps even below competitive prices. Similarly, strategic generators will push the price above competitive prices at times of low wind output when they get to sell additional output. However, the volume weighted price wind generators receive on their output is dominated by the high volumes during high wind periods when prices are low. As a result intermittent generation will generally benefit less from the price increase from market power and in some cases the revenue of intermittent generators might even be surpressed below the revenue they obtain in competitive markets. A possible consequence is that investment will be focused on the technology that offers the highest profitability, reducing the propensity to invest in renewables and/or increasing the subsidy level required to achieve a target level of renewable investment.

Option contracts can provide more flexibility and therefore better match the requirements of intermittent generation. In the first order we are interested in strategic behaviour and ignore the risk hedging component of contracts. As a result, the only party that is directly affected by option contracts are strategic generators. As we are not interested in the risk aversion aspects of options we employ a simple option valuation technique than has been used in other studies of capacity option pricing (Spinler et al, 2002) and wholesale electricity market option research (Burger, 2004; Hjalmarsson 2003). We model contracts they sign with the demand side, both with exogenousely set and endogenously determined contracting volume. These option contracts can reduce but do not eliminate the discrimination of strategic behaviour against intermittent technologies. Our model assumes a fixed, exogenously set, strike price. The results are not sensitive to the strike price - but further research is required to assess the impact of multiple types of option contracts with different strike prices.

The outline of this paper is as follows. Section 2 examines the case of intermittent generation returns under perfect competition. The decrease in returns due to intermittency is demonstrated both graphically and analytically via a simple market model. In section 3, we change the market structure to one of monopoly where the intermittent generators are fringe players in the market. We allow for the possibility of forward contracting by the monopolist. The introduction of market power increases the magnitude of the intermittency effect as compared to perfect competition. In sections 4 and 5, we extend the analysis to a Cournot duopoly where the duopolists can

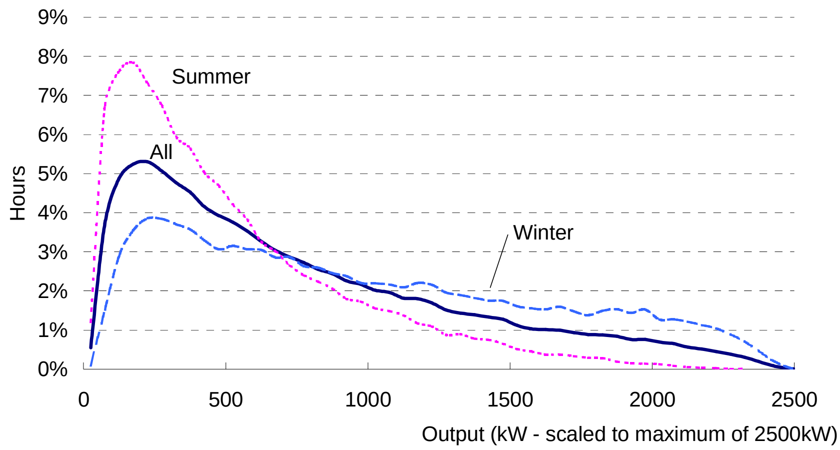

Figure 1: Distribution of hourly wind power output (averaged over UK, Source Graham Sinden)

also conduct forward contracting and option contracting respectively. In section 6, we construct numerical examples of these models using plausible parameters values and examine the sensitivity of these assumptions. Section 7 concludes the paper.

2 Intermittent Generation under Perfect Competition

In an electricity market where intermittent generation, such as wind, comprises a small share of total output, the variability of intermittent output should not be expected to have much effect on the market price. As such, the average price for wind output should be the same as the average market price. However, analysis of resource potentials suggest that intermittent generation could become an increasingly significant share of the total market output (Hoogwijka e.a. 2004). In this case, even in a competitive market, this result no longer holds - variability of output becomes an issue. Figure 1 illustrates that the calculated output of wind turbines averaged over 50 UK sites varies significantly due to the wind volatility. In the presence of increasing marginal costs of conventional generators, during periods of high wind, the conventional generators, which provide

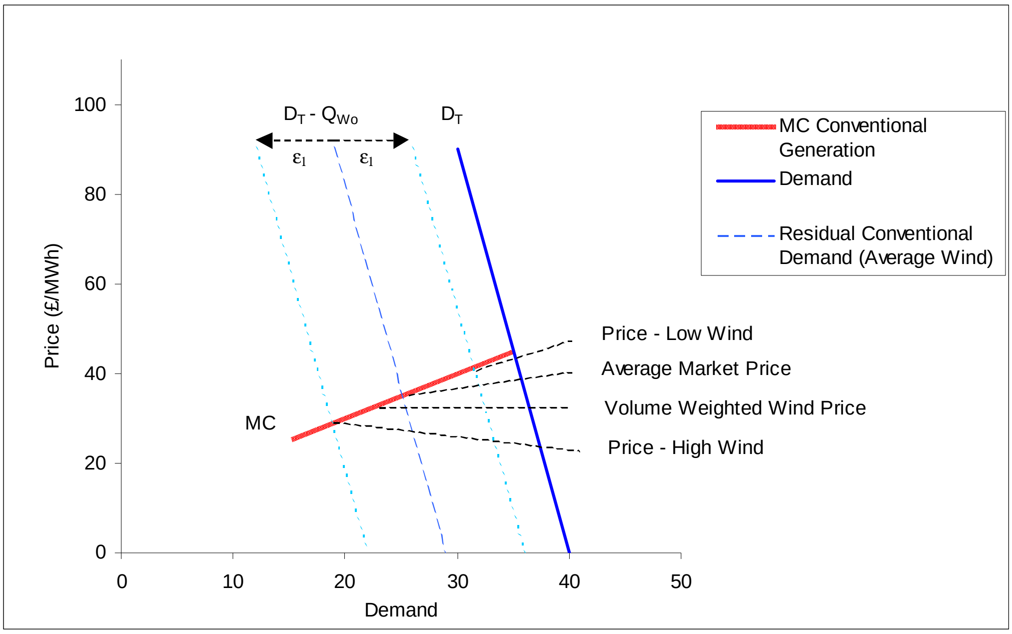

Figure 2: Impact of wind output on market price - competitive case

the marginal generation, will be required to back down and move down the marginal cost curve, resulting in a lower market price. Similarly, during periods of low wind, the conventional marginal generation will be required to increase output, moving up the marginal cost curve or activating higher cost generators, resulting in a higher market price. As a result, the periods of high wind output receive a lower than average price and periods of low wind output receive a higher than average price. The net effect is that the volume weighted average price received by wind is lower than the average market price. Figure 2 illustrates the effect. The variation in the wind output [-ε_1,ε_1] produces a variation in residual demand $(D_T - Q_{w,0})$ and thus a range of market prices for a given marginal cost curve.

The result can be shown more formally using a simple market model. In this section we assume competitive conventional generation, however, in later sections we examine the monopoly and duopoly cases. In all cases we assume that intermittent generation is competitive and for simplicity we will designate it as wind generation. We initially assume that all energy is traded in the spot market and subsequently expand the model to allow for trading of long-term energy contracts by the conventional generators in the period preceeding the spot market. The following table summarises all the symbols that will be used throughout this paper.

D_0	Demand intercept	$Q_{w,0}$	Average wind output
b	Demand slope	ε_w	Deviation from average wind output
D_T	Realised market demand		$\varepsilon_w \tilde{} (0, \sigma_w^2)$ in sections 2-4
			$\varepsilon_w \tilde{}$uniform[-ε_1,ε_1] in sections 5-6
Q_i	Conventional generation output	MC	Marginal costs conventional generator
	competitive and monopoly $i = g$, duopoly $i = A, B$	$\alpha + \beta Q$	Intercept and slope of MC
p	Spot price of electricity	p^*	Expected average spot price
L_i	Forward contract volume of generator i	N_i	Option contract volume generator i
z	Price of forward contracts	r, e	Option price and strike price

Consider a market where market price, p, is a linear function of the total market demand for electricity, D_T:

$$p = D_0 - bD_T \tag{1}$$

Furthermore, assume that electricity is supplied by two different types of generators: conventional generators (such as gas turbine or coal generators) whose collective output is Q_g, and intermittent generators (which we will assume here is wind generation) whose output is assumed to have a fixed and stochastic component $Q_{w,0} + \varepsilon_w$. We assume that $E[\varepsilon_w] = 0$ and $Var[\varepsilon_w] = \sigma_w^2$. The intermittent output is produced by a set of competitive generators that offers all available output at their marginal costs of zero. They are subsequently rewarded at the price of the marginal bid. This is the case in uniform price auctions that are implemented in all European power exchanges, zonal pricing (Nordpool) and nodal pricing (North East of US). Bilateral trades and some balancing mechanisms (e.g. UK) price every contract at the bid price. Bidders anticipate such behaviour and adjust their bid accordingly. For the case of uncertainty and symmetric firms with varying costs Green (presentation CMI workshop November 2004) shows that uniform and pay-as-bid auctions result in the same revenue. This result does not necessarily apply if some firms own wind generation and other firms conventional generation assets.

In equilibrium demand matches supply:

$$D_T = Q_g + Q_{w,0} + \varepsilon_w, \tag{2}$$

and using (1) gives:

$$p = D_0 - b(Q_g + Q_{w,0} + \varepsilon_w). \tag{3}$$

We assume that a conventional generator has a quadratic cost function:

$$C_g(Q_g) = \alpha Q_g + \frac{\beta}{2} Q_g^2, \tag{4}$$

and thus the marginal cost of the conventional generator is:

$$MC_g = \alpha + \beta Q_g. \tag{5}$$

Wind generation is assumed to have a zero marginal cost. The conventional generator is always the marginal generator and sets the market prices. Combining (3) and (5) gives:

$$p = D_0 - b(Q_g + Q_{w,0} + \varepsilon_w) = MC_g = \alpha + \beta Q_g, \tag{6}$$

and equilibrium output and price are

$$Q_g = \frac{D_0 - b(Q_{w,0} + \varepsilon_w) - \alpha}{b + \beta}, \quad p = \frac{\beta(D_0 - b(Q_{w,0} + \varepsilon_w)) + b\alpha}{b + \beta}. \tag{7}$$

The average equilibrium price in the competitive equilibrium, where $E[\varepsilon_w] = 0$, is therefore:

$$p_c^* = E[p] = \frac{\beta(D_0 - bQ_{w,0}) + b\alpha}{b + \beta} \tag{8}$$

The variability of intermittent generation, ε_w, affects both realized output quantities and price. Therefore revenue received by both conventional and wind generators contains the term ε_w^2, which does not average out in expectation. For the wind generator, net-profit (excluding fixed costs) is:

$$
\begin{aligned}
E[\pi_w] = E[p(Q_{w,0} + \varepsilon_w)] &= \frac{\beta(D_0 - bQ_{w,0}) + b\alpha}{b+\beta} Q_{w,0} - \frac{b\beta}{b+\beta}\sigma_w^2 \\
&= p_c^* Q_{w,0} - \frac{b\beta}{b+\beta}\sigma_w^2. \qquad (9)
\end{aligned}
$$

Alternatively, dividing by $Q_{w,0}$, we have the average price received on wind output, p_w:

$$
p_w = p_c^* - \frac{\beta}{b+\beta}\frac{b}{Q_{w,0}}\sigma_w^2. \qquad (10)
$$

Thus the average price received by wind on its output is composed of two parts. The first component is the average market price. The second component is related to the variability of wind output, which we will call the competitive intermittency factor. Given that $b, \beta, \sigma_w^2 > 0$ the intermittency factor is clearly a negative value. With increasing slope of the marginal cost of the conventional generator, β, the impact on the market price from a variation in wind output is increasing and thus leads to a greater intermittency factor. Similarly, the less elastic demand (larger b) the larger the impact of fluctuating wind output on the market price and thus greater intermittency factor. Finally, with increasing variance, σ_w^2, the intermittency effect clearly becomes stronger, while without wind fluctuations ($\sigma_w^2 = 0$) the intermittency factor becomes zero and the wind generators receive the market price p_c.

The competitive intermittency effect reduces the average price on wind output below the average market price. This is not a market failure, but represents the intrinsic lower value of intermittent output relative to firm output. In reality every generation plant can fail, and therefore every generation plant is subject to this intermittency effect. However, the likelihood of plant failure is lower than the likelihood of low wind output. Furthermore, the correlation between individual conventional plant failures is lower than the correlation between low output of intermittent generation of the same technology as climate is to some extent regionally correlated. The next section assesses how market power creates additional price distortions that no longer correspond to differences in the value to the system of intermittent generation.

3 Intermittent Generation under Monopoly

Now let us examine the case where the conventional generator no longer prices at marginal cost but acts as a monopolist. A well known result is that the pricing function of the monopolist is steeper than the underlying marginal cost function. This is illustrated in figure 3. The result is that the effect of the wind intermittency is to increase the magnitude of the difference between the average market price and the volume weighted wind price.

In modelling this effect we introduce some further flexibility by allowing for the monopolist to conduct forward contracting. The effect of forward contracting is to reduce the incentive to raise prices in the spot market. Following Newbery (1998), forward contracting can also be seen as an entry-detering strategy. The monopolist sets the level of forward contracting such that the exercise of market power in the spot market is limited and spot prices do not exceed the price at which entry is profitable.

Let L_g be the contract volume by the conventional generator (monopolist) and z be the price at which contracts are signed. These contracts are sold some time before the final spot market trading. As before, we assume that the intermittent output is produced by a set of competitive generators that offers all available output at their marginal costs of zero. They are subsequently rewarded at the marginal system price (uniform price auction). In the spot market, the profit

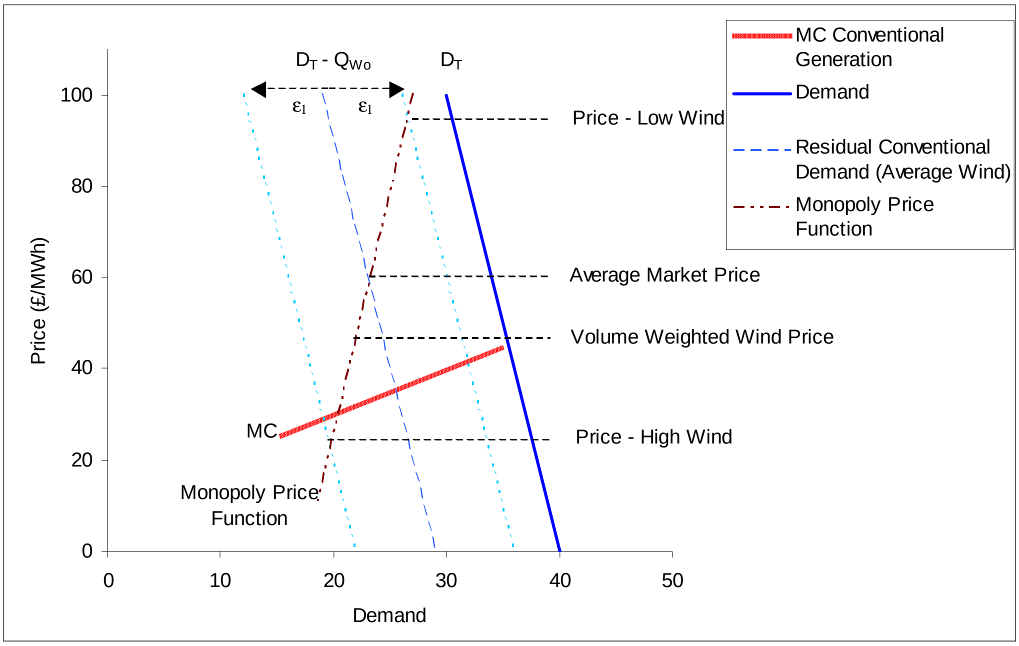

Figure 3: Impact of wind output on market price - monopoly case

for the conventional generator is:

$$\pi_g = p(Q_g - L_g) + zL_g - C(Q_g) = (D_0 - bD_T)(Q_g - L_g) + zL_g - \alpha Q_g - \frac{\beta}{2}Q_g^2$$
$$= (D_0 - b(Q_g + Q_{w,0} + \varepsilon_w))(Q_g - L_g) + zL_g - \alpha Q_g - \frac{\beta}{2}Q_g^2. \quad (11)$$

The first order condition for the choice Q_g is:

$$(D_0 - b(Q_g + Q_{w,0} + \varepsilon_w)) - b(Q_g - L_g) - \alpha - \beta Q_g = 0. \quad (12)$$

From this:

$$Q_g = \frac{D_0 - bQ_{w,0} + bL_g - \alpha - b\varepsilon_w}{2b + \beta}, \quad (13)$$

and from (3) the realized spot price is:

$$p = \frac{(b + \beta)(D_0 - b(Q_{w,0} + \varepsilon_w)) - b^2 L_g + b\alpha}{2b + \beta}. \quad (14)$$

To deter entry, the monopolist chooses a contract level and output volume such that the expected spot price $E[p]$ does not exceed base load entry cost p_m^*. With $\varepsilon_w = 0$ we have

$$E[p] = p_m^* = \frac{(b+\beta)(D_0 - bQ_{w,0}) - b^2 L_g + b\alpha}{2b+\beta} \tag{15}$$

$$L_g = \frac{(b+\beta)(D_0 - bQ_{w,0}) + b\alpha - (2b+\beta)p_m^*}{b^2}. \tag{16}$$

This is a contract level that a monopolist will choose with an expectation of setting an average market price of p_m^*.

From (14) and (15) the realized spot price can be expressed as:

$$p = p_m^* - \frac{b(b+\beta)\varepsilon_w}{2b+\beta}. \tag{17}$$

Examining the expected profit for the wind generator we have:

$$\begin{aligned} E[\pi_w] = E[p(Q_{w,0} + \varepsilon_w)] &= E[(p_m^* - \frac{b(b+\beta)\varepsilon_w}{2b+\beta})(Q_{w,0} + \varepsilon_w)] \\ &= p_m^* Q_{w,0} - \frac{b(b+\beta)}{2b+\beta}\sigma_w^2, \end{aligned} \tag{18}$$

and, similarly as with the competitive case above, we can determine the average price received on wind output, p_w:

$$p_w = p_m^* - \left(\frac{\beta}{b+\beta} + \frac{b^2}{(2b+\beta)(b+\beta)}\right)\frac{b}{Q_{w,0}}\sigma_w^2. \tag{19}$$

Comparing (19) with the competitive case (10) shows that in the monopoly market structure a strategic intermittency factor is added to the competitive intermittency factor. However, the monopoly will also increase the average electricity price, ($p_m^* > p_c^*$), which compensates for some or possibly all the strategic intermittency factor. We will examine a number of numerical examples after looking at the duoploly cases below. Table 1 gives an example of where the monopoly pricing results in the wind generator actually being worse off than in the competitive case despite there being a higher average market price. The assumptions, which include 95% contracting by the monopoly and 0.1 demand elasticity, are at one end of the range of parameter assumptions we will look at in section 6 but are certainly not unreasonable.

	Competition	Monopoly
Average Market Price	35.45	46.52
Competitive Intermittency Factor	3.33	3.33
Strategic Intermittency Factor	0	16.66
Wind Weighted Average Price	32.12	26.52

[1]

Table 1: Impact of intermittency on average wind prices.

4 Intermittent Generation under a Duopoly with Forward Contracting

In practice, most electricity markets are neither perfectly competitive or perfect monopolies. A more common situation is to have the market dominated by a handful of participants. An oligopoly market structure is therefore perhaps the most appropriate assumption in analysing modern electricity markets. In this section we extend the above analysis to modelling oligopoly situations. As with the monoploy analysis we will include forward contracting and in the next section will consider option contracting. Allaz and Vila (1993) first analyzed the effect of forward contracting on Cournot oligopoly. Oligopolists increase their individual market share and profits by foward contracting, and therefore sell some of their output on forward contracts. However, forward contracts reduce the exercise of market power in the spot market and therefore reduce total profits. Therefore oligopolists would be better off to collude by not forward contracting but only monopolies can legally do so.

We assume there are two conventional generators $i = A, B$ with output Q_i, and one intermittent (wind) generator (W). Output of the competitive conventional generator is replaced by output from the oligopolists in equations (2) and (3). In order to ease comparison between

[1] Parameter values: $p = 400 - 10D_T$, $MC_g = 10 + Q_g$,30% wind share with uniform distribution of 100% around average and wind output, and 95% contracting level.

the duopoly and monopoly cases we assume that the marginal costs of the duopolists increase with output at twice the rate as compared to the monopolist. This ensures that the aggregate industry has the same marginal cost curve:

$$C_i(Q_i) = \alpha Q_i + \beta Q_i^2. \tag{20}$$

The game between generators proceeds in two stages. In the first stage the two conventional generators can sign long-term contracts with the demand side. Let L_i be the contract volume of generator $i = A, B$ at contract price z. As we do not model risk aversion, long-term contracts only serve as a strategic instrument. Therefore we do not need to model long-term contracts of the competitive wind generation.

We analyse the model by working backwards. We first consider the stage-two spot market behaviour contingent on the forward contracting volume. Then we look at contract decisions in stage one given that all parties expect the predicted stage two behaviour.

4.1 The Spot Market

Suppose that both duopoly generators have signed contracts for amounts (L_A, L_B) in stage one. Generator A's profit in stage two are:

$$\pi_A = p(Q_A - L_A) + zL_A - \alpha Q_A - \beta Q_A^2. \tag{21}$$

Substituting p from (3) with $Q_q = Q_A + Q_B$ gives:

$$\pi_A = [D_0 - b(Q_A + Q_B + Q_{w,0} + \varepsilon_w)](Q_A - L_A) + zL_A - \alpha Q_A - \beta Q_A^2. \tag{22}$$

The profit maximising output choice of A follows from setting the derivative of (22) with respect to Q_A to zero:

$$Q_A = \frac{bL_A + D_0 - b(Q_B + Q_{W,0} + \varepsilon_w)] - \alpha}{2b + 2\beta}. \tag{23}$$

Using the symmetric expression for Q_B and substituting in (23) gives:

$$Q_A = \frac{(2b+2\beta)bL_A - b^2 L_B + (b+2\beta)[(D_0 - b(Q_{W,0}+\varepsilon_w) - \alpha)]}{(2\beta+3b)(2\beta+b)}. \tag{24}$$

The quantity sold in the spot market by generator A is an increasing function of the contracting level L_A and decreasing function of L_B. Substituting (24) and its symmetric expression for Q_B into (3) with $Q_q = Q_A + Q_B$ gives:

$$p = \frac{(2\beta+b)\left(D_0 - b\left(Q_{W,0}+\varepsilon_w + L_A + L_B\right)\right) + 2b\left(\alpha + \beta(L_A+L_B)\right)}{2\beta+3b} \tag{25}$$

$$= \frac{(2\beta+b)\left(D_0 - b(Q_{W,0}+\varepsilon_w)\right) + 2b\alpha - b^2(L_A+L_B)}{2\beta+3b}. \tag{26}$$

The first line of (25) shows that forward contracting only results in a small change to the usual Cournot duopoly equation. Forward contracting volumes are directly deducted from the total available market share (L_i in first part of numerator) and the smaller market results in lower prices. But forward contracting volumes also increase the base level of marginal cost and therefore optimal price for additional output (L_i in second part of numerator). The effect of the smaller remaining market dominates the increase marginal cost and the second line (26) shows that total market price is strictly decreasing in contracting volume.

The expected market price in the oligopoly market, p_o^*, follows from setting $\varepsilon_w = 0$ in (26):

$$p_o^* = \frac{(2\beta+b)[(D_0 - bQ_{W,0})] + 2b\alpha - b^2(L_A+L_B)}{2\beta+3b}, \tag{27}$$

and we can rewrite the realized market prices as:

$$p = p_o^* - \frac{b(2\beta+b)}{2\beta+3b}\varepsilon_w. \tag{28}$$

4.2 The Contract Market

In period one the contracts are signed. The counterparty to the strategic generators is assumed to behave competitively and will therefore sign the contracts at the expected spot price. That is

$z = p_o^*$. Therefore, from (22) and (28) the Cournot generator expects the following profits:

$$\begin{aligned} E[\pi_A] &= E[p(Q_A - L_A) + p_o^* L_A - \alpha Q_A - \beta Q_A^2] \\ &= E[(p - \alpha - \beta Q_A) Q_A] \end{aligned} \tag{29}$$

Taking the derivative with respect to the contracting choice L_A and substituting from the the symmetric expression for L_B gives the equilibrium contract levels:

$$L_i = \frac{b(D_0 - bQ_{W,0} - \alpha)}{5b^2 + 10b\beta + 4\beta^2}, \tag{30}$$

By substituting this into (27), the corresponding expected price is:

$$z = p_o^* = \frac{\left(\begin{array}{c} -3b^4 Q_{w,0} + 8\beta^3 D_0 + 4b^2\beta(5D_0 + 5\alpha - 6\beta Q_{w,0}) \\ -4b\beta^2(-6D_0 - 2\alpha + 2\beta Q_{W,0}) + b^3(3D_0 - 4\beta(-6\alpha + 5Q_{w,0})) \end{array} \right)}{(3b + 2\beta)(5b^2 + 10b\beta + 4\beta^2)}, \tag{31}$$

and average output quantities:

$$E[Q_A] = E[Q_B] = \frac{\left(\begin{array}{c} -6b^3 q_{w,0} + 4\beta^2(D_0 - \alpha) + 2b\beta(5D_0 - 5\alpha - 2\beta Q_{w,0}) \\ -b^2(6D_0 - 6\alpha + 10\beta Q_{W,0}) \end{array} \right)}{(3b + 2\beta)(5b^2 + 10b\beta + 4\beta^2)}.$$

These analytic results will be used in later numerical examples to illustrate the impact of different contracting arrangements.

4.3 Wind generator

The expected profit of the wind generators follows from substituting p from (28) into the net-profit equation:

$$\begin{aligned} E[\pi_w] = E[p(Q_{w,0} + \varepsilon_w)] &= E[(p_o^* - \frac{b(2\beta + b)\varepsilon_w}{(2\beta + 3b)})(Q_{w,0} + \varepsilon_w)] \\ &= p_o^* Q_{w,0} - \frac{b(2\beta + b)}{(2\beta + 3b)} \sigma_w^2, \end{aligned} \tag{32}$$

and as with the competitive and monopoly cases the net-profit equation is used to calculate the average price received on wind output:

$$p_w = p_o^* - \left(\frac{\beta}{b+\beta} + \frac{b^2}{(3b+2\beta)(b+\beta)} \right) \frac{b}{Q_{w,0}} \sigma_w^2. \tag{33}$$

As in the monopoly case the price is not only reduced by the competitive intermittency factor but also by the strategic intermittency factor (second component in the bracket). However, the strategic intermittency factor is smaller than in the monopoly case, because the the equilibrium price curve (as a function of net-demand) is less step in the duopoly case than it is in the monopoly case. However, not only the intermittency factor, but also the average price varies between the scenarios. A numerical comparison of the net effect is presented in section 6. Note that the competitive intermittency and strategic intermittency factor are (in our linear model) not a function of the equilibrium price and therefore independent of forward contracting levels.

5 Intermittent Generation under a Duopoly with Option Contracting

We now complete the analysis by considering the case of option contracting rather than forward contracting.[2] For simplicity we assume that conventional generators can sell options which are sold to competitive buyers and therefore priced competitively and where the strike price is set exogenously. For the purposes of this analysis we use a very simple option pricing technique that is based on an expected value calculated via the weighted probability of contigent states. As compared to more sophisticated option valuing techniques (e.g. Black Scholes) we are making a number of assumptions which include no risk aversion and zero interest rates. However, as we are only concerned with the strategic aspects of contracting this simplified approach is consistent

[2] For another perspective on the use of financial options, particularly as to how they compare with forward contracting in reducing market power under a Cournot setting, see Willems (2004).

with the aims of this paper.

With the inclusion of options, there are three relevant possible states of the world in the spot market for period two: (1) those states in which the options are all exercised (2) those states in which the options are not exercised and (3) those states in which a fraction of the options are exercised as buyers are indifferent between exercising their options or not exercising them (i.e. the spot price equals the strike price). In the appendix we determine the optimal quantities and corresponding market spot prices for each of these states and then derive the optimal option contracting level in period one. As it turns out, the competitive intermittency and strategic intermittency factors for the states (1) and (2) reduce to the case of forward and zero forward contracting discussed in section 4.2 (see equation 33). For state (3), the intermittency factor is zero as there is no variation in the price level for the variations of wind output in this range. The aggregate intermittency factor is a weighted average of these three cases. Numerical examples are presented in the next sections.

6 Numerical Examples

To examine the signficance of the strategic intermittency factor we present some numerical examples of the above models using plausible parameter values. We assume an inverse demand function of $p = 400 - 10D_T$ which, along with the other assumptions, translates into a demand elasticity of approximately 0.1. For short-term electricity demand response this is a still a rather high elasticity level therefore we are likely to understate the effect. We assume a marginal cost function of the conventional generators as $MC_g = 10 + Q_g$. The absolute price is of little concern as we are interested in the relative intermittency factor and market power margin. Average wind output is set at $Q_{w,0} = 11$, which equals approximately 30% of realised demand. Total wind output is uniformly distributed around the average output [0-22]. The strike price for the option

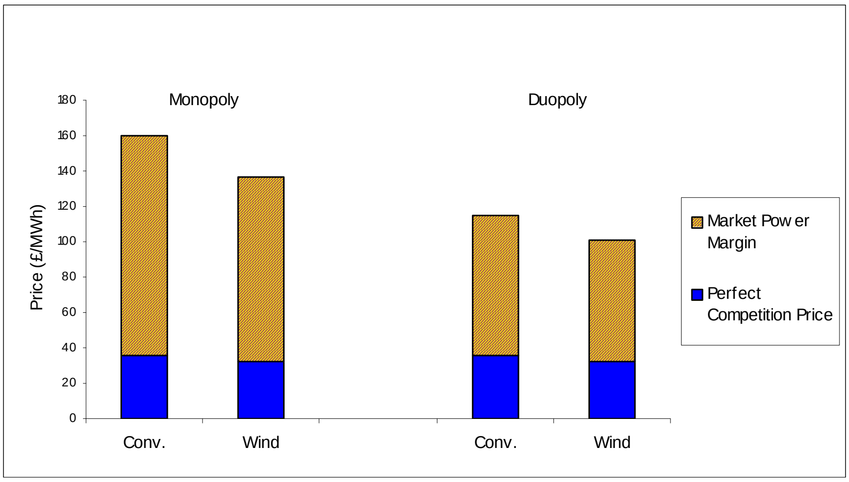

Figure 4: Average price and volume weighted price for wind - no contracting

contracting is set at average competitive market price of 35.5. We examine below the sensitivity of results tosome of these assumptions.

Figure 4 presents the simplest case of the effect of market power under the monopoly and duopoly market structures with no contracting by the conventational generator(s). The Figure decomposes the price into the price received under perfect competition and the additional margin due to market power. As discussed earlier, even in the absence of market power, the conventional generator(s) receives a higher average price on output than the wind generators. This is the result of the competitive intermittency factor and is small but significant. With the introduction of market power not only does the average price level increase but so does the difference in returns to conventional and wind output due to the strategic intermittency factor. Without contracting, spot prices always exceed marginal cost prices and therefore wind always benefits from market power, albiet to a lesser degree than conventional generation. Figure 4 illustrates that without contracting generators could exercise excessive amounts of market power. To obtain realistic results we have to reflect the impact of forward contracting.

In Figure 5 the results of introducing endogenous contracting by the conventional generators

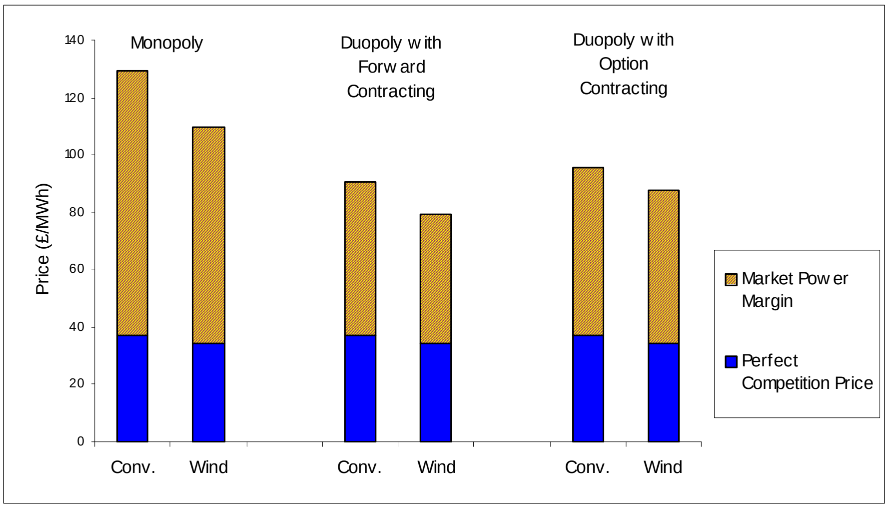

Figure 5: Average price and volume weighted price for wind - endogenous contracting (45% and 51%)

are presented. In equilibrium each duopolist will sell about 45% of output on forward contracts. In the scenario with option contracting approximately 51% of output is contracted. A monopolist will not voluntarily forward contract because he only incurs the 'cost' of restraining his market power but not the benefit of capturing competitors' market share. To facilitate comparison between the cases we exogenously set the forward contracting level of the monopolist at 45%.

For both the monopoly and oligopoly forward contracting cases the strategic intermittency factor is not a function of the forward contracting level (see equations 19 and 33). However, forward contracting reduces the absolute price level. Therefore the relative importance of the strategic intermittency factor increases compared to the no contracting case.

The market power margins in Figure 5 are still far higher than typically observed. This is partly because in practice forward contracting volumes are typically far higher than the 45-50% levels that emerge from the model here. Allaz and Villa (1993) explain the higher contracting volumes by repeated contracting stages. In their model, moving towards infinite contracting stages results in strategic generators forward contracting all output with prices converging towards competitive levels. Other possible factors resulting in higher contracting volumes include risk aversion or requirements by competition authorities (e.g. virtual power plant auctions). We therefore model a case where we exogenously set contracting volumes at 90% of expected output by conventional generators. Figure 6 shows that large volumes of forward contracting bring the prices closer to competitive levels and to market power mark-ups in the duopoly case that seem realistic. With 90% forward contracting the strategic intermittency factor almost eliminates the market power margin for the wind generator in the duopoly market.. Table 1 showed that in the case with 95% foward contracting the strategic intermittency factor is bigger than the duopoly mark-up and therefore market power even reduces the revenue for wind generation relative to the competitive case. This latter example is a case of an absolute bias against intermittent generation where wind is actually worse off under a market power structure than under a competitive market structure. Our numerical cases in this section have illustrated only a relative bias against intermittent generation in which wind is still better off under a market power environment but to relatively less degree than conventional generation. In our base case, a contracting level of 92.3% is the threshold level. For any contracting level above 92.3% wind is absolutely worse off. This can be seen clearly at 100% contracting where the average market price equals the competitive price but to which the magnitude of the strategic intermittency factor remains the same and thus the wind price is grossly below the competitive price.

In the option contracting case the strike price was again set in the mid range of the observed prices at 35 £/MWh. The result with option contracts differs from the result with forward contracts, because generators have no incentive to push the spot price below competitive prices at times when they produce less energy then they contracted for. This has two implications. First, the average price level stays higher as can be observed by comparing the average price paid to conventional generators in forward and option contracting case. Secondly, the intermittency

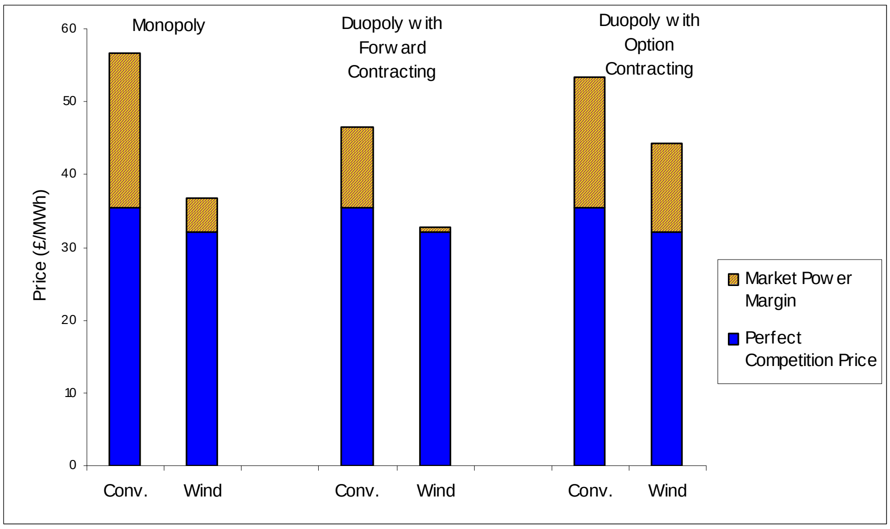

Figure 6: Average price and volume weighted price for wind - 90% contracting

discount is lower, because at times with high wind output market power does not distort prices to be below marginal costs of conventional generators. As a result option contracting results in less discrimination against intermittent generation than forward contracting. The sensitivity of the results to different choices of strike prices is presented in Figure 7. With strike prices below 7 the options are always called and we revert to the forward contracting case. As the strike price is increased (e.g. 25 £/MWh) more of the downward price deviations are avoided and volume weighted wind price increases by more than the average price. With increasing strike price the options are called less frequently and average weighted wind prices increases. With strike above 150 the options are never called and the result corresponds to the no forward contracting case.

For all strike prices the average price levels paid to conventional generation exceed the price in the forward contracting case. This is partially caused by a model simplification. We only model one type of option contract with a fixed strike price. As marginal costs are increasing the strike price always exceeds marginal costs over part of the output range. And therefore the option contracting with only one strike price will never converge to the competitive equilibrium

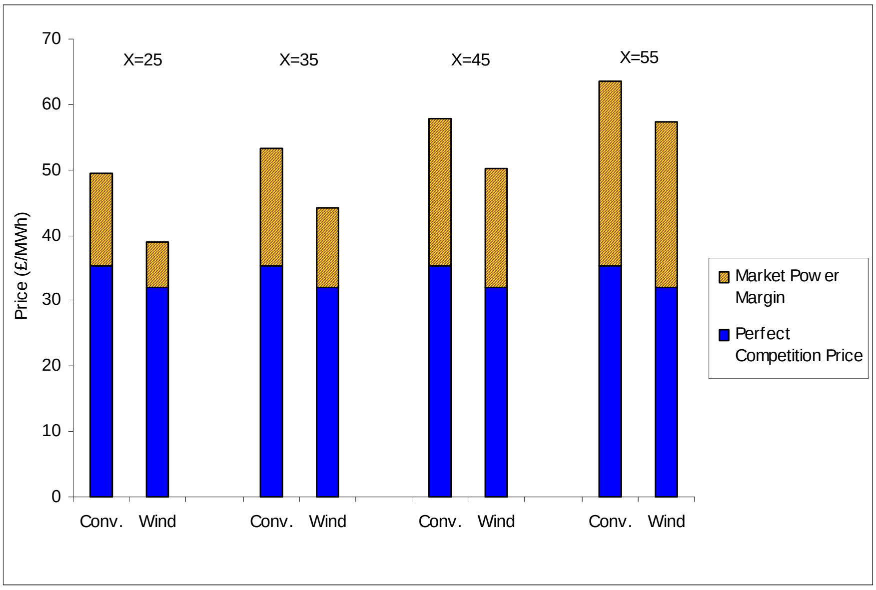

Figure 7: Average price and volume weighted price for wind - different option strike prices

even with 100% option contracting. In contrast, if for each output level an option contract with strike price at the marginal costs of this output level is signed, then 100% option contracting results in a competitive outcome.

This result can be interpreted as a constraint on the model - or as a policy indication that simple option contracts will not suffice to eliminate distortions from market power.

Finally we examine the sensitivity of the results to other assumptions in the model. In Figure 8 the base case is the duopoly with 90% forward contracting. In the second set of columns the variation in wind output is reduced from 100% of the average to 75% of average. As a result the competitive and strategic intermittency factors are reduced but remain significant. We also tripled the spot market demand elasticity to 0.3. The effect is a reduction of market power and intermittency factor. Finally a reduction of the share of wind output from an average of 30% to 15% is examined. Once again the effect is a reduction of the competitive and strategic intermittency factors but they still remain significant.

The effect described in this paper can impact on all technologies with output that (1) cannot

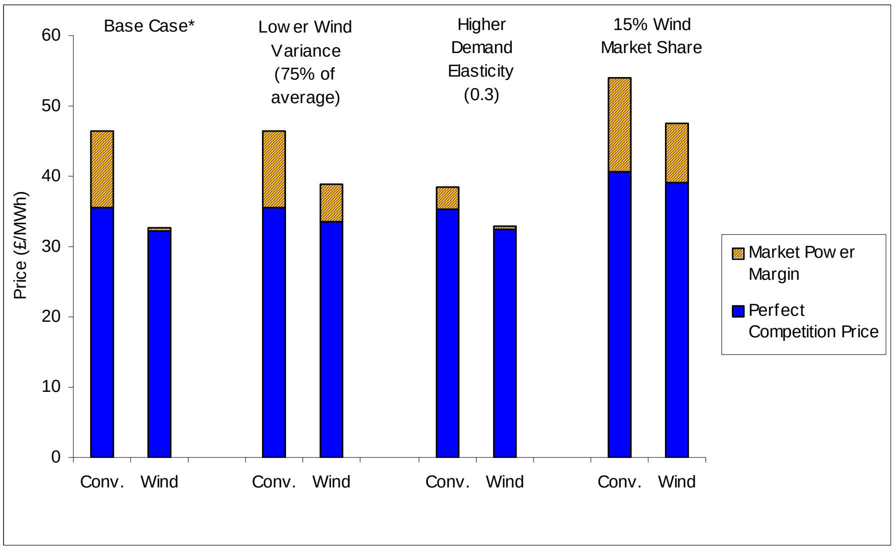

Figure 8: Average price and volume weighted price for wind - other scenarios

be predicted on a long term horizon (for contracting), (2) have plant output deviations that are correlated, and (3) the technology has a sufficiently large market share. Wind power satisfies this requirement. Not affected are solar photovoltaics because of its currently small market share and tidal energy because output can be predicted long-term and can therefore be covered with long-term contracts.

7 Conclusions

Transmission constraints separate electricity markets - and therefore create market power for local generators. It is difficult to create sufficient local competition and costly to eliminate all transmission constraints. Therefore a recurring response is that a limited amount of market power is unavoidable. A limited amount of market power is sometimes perceived as acceptable as it creates revenues for generators to cover some of the fixed costs. It is assumed that all market participants benefit equally from the increased prices. However, this assumption is not satisfied if different production technologies are used. We assess the case of a generation mix of conventional generation and intermittent generation with exogenously varying production levels. If all output is sold in the spot market, then intermittent generation benefits less from market power than conventional generation. If forward contracts or option contracts are signed, then market power might be reduced but the bias against returns to intermittent generators persists. Thus allowing some level of market power as a means of encouraging investment in new generation may result in a bias against intermittent technologies or increase the costs of strategic deployment to achieve renewable quotas. Likewise market power monitoring, if it only focuses on retaining the average spot price or the price paid by consumers below a certain level, is likely to ignore the distortions market power can still create between different technologies. This paper suggests that option contracts might eliminate some of the distortions as strategic generators selling output on option contracts will not push the spot price below competitive levels as they would when buying back electricity at times of excess supply from intermittent generation. However, our model shows that high levels of option contracts are required. The model also shows, that only one set of simple option contracts with a uniform strike price are only of limited value. More complex contracting structures are subject to future research.

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8 Appendix

The determination of optimal contracting for the three possible states at the expiry of the option

For simplicity we assume that conventional generators can sell options which are priced competitively and where the strike price is set exogenously. For the following analysis we will also assume that the volatility of wind, ε_w, follows a uniform distribution on $[-\varepsilon_m, +\varepsilon_m]$. The probability density function (pdf) of this wind disturbance term is therefore:

$$pdf(\varepsilon) = \left\{ \begin{array}{cc} \frac{1}{2\varepsilon_m} & \text{for } \varepsilon\epsilon[-\varepsilon_m, +\varepsilon_m] \\ 0 & \text{otherwise} \end{array} \right\} \tag{34}$$

As with the forward contracting case, the game between two generators proceeds in two periods. In the first period generators can sell option contracts to someone (e.g. consumers, retailers). The amount they sell depends on the expectation of profits in the spot market in period two. We define the price at which the option is sold as r. Buying the option allows a consumer to buy electricity at strike price e, therefore the consumer will exercise the option whenever the spot price exceeds e. Strategic generator $i = A, B$, sells the volume N_i of options. As before we analyse the model by working backwards, considering state two spot market behaviour and then analyse the equilibrium volume of options sold in stage one.

The Spot Market

Consider the three different possible states of the world in the spot market in period two: (1) those states in which the options are all exercised (2) those states in which the options are never exercised and (3) those states in which a fraction of the options are exercised, as consumers are indifferent between exercising their option or not exercising it (i.e. the spot price equals the strike price). We determine the optimal quantities of contracting for each of these states (dependent on option contracting level) and then derive the optimal option contracting in period one.

State 1: Option Exercised

In this state the realized profit by the conventional generator is:

$$\pi_A^H = p^H(Q_A^H - N_A) + rN_A + eN_A - \alpha Q_A^H - \beta Q_A^{2H}, \tag{35}$$

i.e. conditional on the option being exercised, the profit is equal to the revenue from uncontracted sales into spot market plus the premium from selling N options plus revenue on the sale of N units of electricity on called options minus the cost of electricity produced. The profit, quantity, and price variables are superscripted with H which signifies the state of 'High' prices when the options are exercised.

In a very similar manner to the forward contracting case above, by substituting p from (3) with $Q_q = Q_A^H + Q_B^H$ gives:

$$\pi_A^H = [D_0 - b(Q_A^H + Q_B^H + Q_{W,0} + \varepsilon_w)](Q_A^H - N_A) + rN_A + eN_A - \alpha Q_A^H - \beta Q_A^{2H}. \tag{36}$$

Taking the first order condition yields with respect to Q_A^H yields:

$$Q_A^H = \frac{bN_A + D_0 - b(Q_B^H + Q_{W,0}^H + \varepsilon_w)] - \alpha}{2b + 2\beta}, \tag{37}$$

Using the symmetric equation for Q_B^H and subsituting in (42) gives:

$$Q_A^H = \frac{(b + 2\beta)(D_0 - bQ_{W,0} - \alpha - b\varepsilon_w) + (2b + 2\beta)bN_A - b^2 N_B}{(2\beta + 3b)(2\beta + b)}, \tag{38}$$

and the corresponding price:

$$p^H = \frac{(b + 2\beta)(D_0 - bQ_{W,0} - b\varepsilon_w) + 2\alpha b - b^2(N_A + N_B)}{(2\beta + 3b)}. \tag{39}$$

State 2: Option Not Exercised

In those states of the world in which the option is not exercised the conventional generator will have a profit of:

$$\pi_A^L = p^L Q_A^L + rN_A - \alpha Q_A^L - \beta Q_A^{2H}.$$

By proceeding with a similar substitution for price and using the symmetric first order conditions we obtain:

$$Q_A^L = \frac{(D_0 - bQ_{W,0} - \alpha - b\varepsilon_w)}{(2\beta + 3b)}, \tag{40}$$

$$p^L = \frac{(b + 2\beta)(D_0 - bQ_{W,0} - b\varepsilon_w) + 2\alpha b}{(2\beta + 3b)}. \tag{41}$$

State 3: Option Partially Exercised

There is also an intermediate case where some but not all options are exercised. The feature of this set of states, associated with a range of ε_w, is that the price is always equal to the exercise price. This is in fact why partial exercise is rational, and not an either/or decision, as a holder of the options is indifferent between exercising the options (and making zero profit if the electricity is sold back into the spot market) or letting the options expire. Thus $p = e$ and substituting p from (3) with $Q_q = Q_A^H + Q_B^H$ gives:

$$p^M = D_0 - b(Q_A^M + Q_B^M + Q_{w,0} + \varepsilon_w).$$

The superscript M represent this 'middle' state. With $p = e$ and adding the assumption of symmetry $Q_A^M = Q_B^M$ gives:

$$\begin{aligned} e &= D_0 - b(Q_A^M + Q_A^M + Q_{w,0} + \varepsilon_w), \\ Q_A^M &= \frac{D_0 - bQ_{w,0} - b\varepsilon_w - e}{2b}. \end{aligned} \tag{42}$$

Thus, we have a determined Q_A^M for any given ε_w in this intermediate case.

Valuing the Option in Stage One

In equilibrium we assume that the value of the option is equal to the expected value from the three possible classes states. Assuming a simple two period case with no interest rates, the value of the call option may be calculated as the expected value over all possible realisations of ε_w. Using (34) gives:

$$\begin{aligned} r &= \int_{-\varepsilon_m}^{\varepsilon_d} \frac{1}{2\varepsilon_m}(p^H - e)d\varepsilon + \int_{\varepsilon_d}^{\varepsilon_u} \frac{1}{2\varepsilon_m}(e - e)d\varepsilon + \int_{\varepsilon_u}^{\varepsilon_m} \frac{1}{2\varepsilon_m} 0 d\varepsilon \\ &= \int_{-\varepsilon_m}^{\varepsilon_d} \frac{1}{2\varepsilon_m}(p^H - e)d\varepsilon, \end{aligned} \tag{43}$$

where ε_d is the highest level of wind up to which all the options are exercised and ε_u is the lowest level of wind down to which no option is exercised. Equation (43) can be interpreted such that the value of the option is derived from the excess of price over the strike price in those states when wind is sufficiently low.

From (39) we obtain:

$$p^H = \frac{(b+2\beta)(D_0 - bQ_{W,0} - b\varepsilon_w) + 2\alpha b - b^2(N_A + N_B)}{(2\beta + 3b)}, \tag{44}$$

and for the special case of $p^H = e$, when $\varepsilon_w = \varepsilon_d$ (ie. we are just at the point where all the options are exercised), we have:

$$e = \frac{(b+2\beta)(D_0 - bQ_{W,0} - b\varepsilon_d) + 2\alpha b - b^2(N_A + N_B)}{(2\beta + 3b)}. \tag{45}$$

Recall that e is exogenous, so (45) provides a relationship between N_A, N_B and ε_d.

Substituting (44) and (45) in (43) yields:

$$\begin{aligned} r &= \int_{-\varepsilon_m}^{\varepsilon_d} \frac{1}{2\varepsilon_m}\Big(\frac{(b+2\beta)(D_0 - bQ_{W,0} - b\varepsilon_w) + 2\alpha b - b^2(N_A + N_B)}{(2\beta + 3b)} \\ &\quad - \frac{(b+2\beta)(D_0 - bQ_{W,0} - b\varepsilon_d) + 2\alpha b - b^2(N_A + N_B)}{(2\beta + 3b)}\Big) d\varepsilon \\ &= \int_{-\varepsilon_m}^{\varepsilon_d} \frac{1}{2\varepsilon_m}\Big(\frac{-b(2\beta + b)(\varepsilon_w - \varepsilon_d)}{(2\beta + 3b)}\Big) d\varepsilon_w \\ &= \frac{b(b+2\beta)\left(\varepsilon_m + \varepsilon_d\right)^2}{4(2\beta + 3b)\varepsilon_m} \end{aligned} \tag{46}$$

Determining the Option Contracting Volume in Stage One

In period 1, the expected profit in period 2 is the probability weighted profits from each possible state of the world in period 2:

$$\begin{aligned} E[\pi_A] &= \int_{-\varepsilon_m}^{\varepsilon_d} \frac{1}{2\varepsilon_m}(p^H(Q_A^H - N_A) + rN_A + eN_A - \alpha Q_A^H) + \int_{\varepsilon_d}^{\varepsilon_u} \frac{1}{2\varepsilon_m}((e-\alpha)Q_A^M + rN_A)) \\ &\quad + \int_{\varepsilon_u}^{\varepsilon_m} \frac{1}{2\varepsilon_m}(p^L Q_A^L + rN_A - \alpha Q_A^L) \end{aligned} \tag{47}$$

In evaluating this expression we can be assisted by considering the constraint that arises at the exercise price:

$$\begin{aligned} e &= p_{\varepsilon_d}^H = \frac{(b+2\beta)(D_0 - bQ_{W,0} - b\varepsilon_d) + 2\alpha b - b^2(N_A + N_B)}{(2\beta + 3b)} \\ &= p_{\varepsilon_u}^L = \frac{(b+2\beta)(D_0 - bQ_{W,0} - b\varepsilon_u) + 2\alpha b}{(2\beta + 3b)} \end{aligned} \tag{48}$$

Two particular relationships from this that are useful are:

$$\varepsilon_u = \frac{(b+2\beta)(D_0 - bQ_{W,0}) + 2\alpha b - (3b+2\beta)e}{b(2\beta+b)} \tag{49}$$

$$\varepsilon_d = \varepsilon_u - \frac{b}{b+2\beta}(N_A + N_B) \tag{50}$$

By substituting (38) (39), (40), (41), (42), (46), (49) and (50) into (47) and solving for N_A and N_B we get:

$$N_A = N_B = \frac{b^2 D_0 + 3b^2 e - b^3 Q_{w,0} - 4b^2\alpha + 2b\beta D_0 + 2b\beta e - 2b^2\beta Q_{w,0} - 4b\beta\alpha + b^3\varepsilon_1 + 2b^2\beta\varepsilon_m}{2(4b^3 + 10b^2\beta + 6b\beta^2 + \beta^3)}.$$

Unfortunately the analytic expressions for p_w is too long to be replicated here. However, it is fairly easy to see that the intermittency and strategic intermittency factor for the states 1 and 2 reduce to the case of forward contracting discussed in section 4.2 (see equation 33). For state 3, the intermittency factor is zero as there is no variation in the price level with wind output. The aggregate intermittency factor is a weighted average of these three cases and therefore lower than the equivalent level of forward contracting.