Using Weather Derivatives to Improve the Efficiency of Forward Markets for Electricity*

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Abstract

The analysis in this paper demonstrates that a combination of 1) a forward contact, with fixed price for both base land and peaking power, and 2) a collar option for the number of hot days in a summer is an effective way to reduce the risk of purchasing electricity in a spot market. The main advantages are 1) the effectiveness of price signals is strengthened by making peaking power expensive, and 2) the correlation between payouts from the weather option and high prices is increased.

1. Introduction

Recent experiences in the Californian market for electricity during the winter 2001 have illustrated that conditions can be very bad for customers. High prices combined with a lot of uncertainty about future market conditions put customers or their agents at a distinct disadvantage. In general, suppliers benefit from these same market conditions and are not willing to consider contracts that are not in their own interest. As a result, the prices in these contracts may still be much higher than they would be in a truly competitive market.

The objective of this paper is to use weather options to deal with the risk faced by customers in a volatile market for electricity. Even though this alternative will not reduce prices in the short run, it is more likely that prices will be lower in the long run. The reason is that price signals are maintained, and the weather options provide a hedge against high prices. If customers rely exclusively on a fixed contract price, it will be somewhere between the fair competitive price and the highest prices observed in the spot market. Consequently, using a forward contract undermines the effectiveness of market forces in real time when prices are high.

Earlier research by Ethier (1999) and Ning (2001) has shown that price behavior in electricity markets can be represented by a stochastic regime-switching model. One regime has low prices with little variability and the other high prices with a lot of variability. The size and frequency of the high prices determine, to a large extent, the overall average price in the market and the level of volatility of prices. The rationale for this price model is supported by evidence from the Pennsylvania, New Jersey and Maryland (PJM) market (see Mount, Ning and Oh (2000)). Offer curves into the PJM market look like a hockey stick. Most of the capacity is offered in at relatively low prices (the shaft), but a small proportion of capacity is offered in at very high prices (the blade). This kinked offer curve is consistent with a regime-switching model. The important implication for the paper is that supply is very price inelastic when high prices occur. Hence, load response to high prices can be a powerful way to discipline a typical market for electricity.

The main contribution of this paper is to show how weather derivatives can be used to hedge against high prices. In reality, these options do not work very well as direct hedges against high prices in the spot market. The proposal in this paper is to combine a collar option for hot days with a forward contract for electricity under which

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the price of peaking power is high and the price of baseload power is low. The high price of peaking power and the associated uncertainty about how much of this power will be needed makes the forward contract relatively risky. This risk, however, can be hedged by the option for hot days. The form of the contract for power makes the relationship between high loads and high prices stronger than it is in the spot market, and as a result, it is easier to hedge effectively.

2. Characteristics of the Spot Market for Electric Power

An important characteristic of a typical spot market for electricity is that levels of demand are high when the prices are high. Hence, the uncertainty that exists about daily prices is compounded by the uncertainty about daily levels of demand. In other words, price risk and volumetric risk are positively correlated. Since the level of demand (load) is positively correlated with the temperature during the summer months, when spot prices are typically highest, weather derivatives of an appropriate form can be used to hedge against the cost of purchasing power.

The objective of this section is to present a simple model of demand behavior that captures the important features of a spot market for electricity. In this model, there are cool days and hot days. The load and price are both higher on hot days. In addition, price spikes are more likely to occur on hot days, but they can also occur on cool days. Hence, even though the temperature is perfectly correlated with the load in this simple market, price spikes are not perfectly correlated with the temperature.

The values of the parameters used for the empirical analysis are summarized in Table 1. The loads are chosen to represent a residential customer who purchases about 700 kWh each month, and the analysis that follows focuses on the financial implications of purchasing power for this typical customer.

Table 1. Characteristics of the Spot Market for Electricity

Probability of a hot day	0.25
Probability of a high price on a hot day	0.60
Probability of a high price on a cool day	0.05
Demand on a hot day	30 kWh/day
Demand on a cool day	20 kWh/day
High price	30¢/kWh
Low price on a hot day	5¢/kWh
Low price on a cool day	3¢/kWh

On a cool day, the cost of buying power for this customer will be \$0.6/day (20 x .03) most of the time, but occasionally it will be \$6.0/day (20 x .3) when a price spike occurs. On hot days, the corresponding costs are \$1.5/day (30 x 0.05) and \$9/day (30 x 0.3), and there is a high probability of 60% that the high cost will occur. Hence, the daily cost of buying electricity in the spot market varies by a factor of 15 from \$0.6/day to \$9/day.

For a customer, the daily variability of costs is not as important as the variability of the monthly bill. This same argument applies to the Distribution Company (DISCO) supplying the customer. Hence, it is not necessary to hedge against daily variability in costs to meet reasonable financial goals. In the following analysis, the chosen electricity criterion is the total cost for a summer, consisting of 92 days. The objective of the analysis is to evaluate the effectiveness of different types of forward contracts as ways to reduce uncertainty about the total cost for the summer.

For any given hot or cool day, the level of demand is completely price inelastic. A customer would like the total cost to be low and stable. This is also true for a DISCO if customers are paying fixed, regulated rates for power. If purchases are made in the spot market, the primary source of uncertainty about the total cost is the stochastic nature of the number of days when prices are high. Assuming that hot days and high prices are determined by independent binominal processes, it is straightforward to determine the statistical properties of the total cost of purchasing power on the spot market. However, it is instructive to look at the magnitudes of different sources of risk in the market. For this purpose, a sample of 5,000 summers were generated. With this empirical approach, it was then possible to specify a realistic function to describe risk averse behavior to financial losses. Opportunities for gains from forward contracts for both a DISCO and a Generating Company (GENCO) depend heavily on the desire of the DISCO to avoid large losses.

Using the parameters in Table 1, there are 23 hot days and 17 days with high prices on average, but the sample includes summers with up to 30 days with high prices. On average, 20 per cent of the high prices occur on cool days and are thus unrelated to the temperature.

In Table 2, the effects of changing the magnitude of the high price are illustrated. If the high price is only ¢15/kWh, the average price paid is about ¢6/kWh and the average cost for the summer is \$125/summer. In contrast, when the high price is ¢45/kWh, the average price paid and total cost more than double to ¢13/kWh and \$270/summer, respectively. The parameter values for this analysis were chosen under the assumption that a regulated price would be ¢6/kWh, and consequently, using a high price of ¢30/kWh for the analysis implies that the average price and total cost have turned out to be

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50% higher than the levels expected when the market was restructured. This situation puts financial pressure on the DISCO, and at the same time, is a major benefit to the GENCO.

Table 2. The Effects of Price Spikes on Total Cost

High Price (¢/kWh)	Av. Price Paid (¢/kWh)		Total Cost	($/Summer)
	Mean	St. Dev.	Mean	St. Dev.
15	6.05	0.56	125.43	13.59
30	9.54	1.28	197.72	29.39
45	13.02	2.00	270.00	34.29

For the following analysis, it is assumed that the market is in a transition from a regulated system and that customers are still paying a fixed regulated rate of ¢15/kWh. The DISCO is a former fully integrated utility that had to divest all generating assets. When the rate was set, the expectation of the regulators was that ¢6/kWh would cover the full cost of buying power, ¢4/kWh would cover out-of-pocket expenses for transmission and distribution (T&D), leaving ¢5/kWh to cover strandable assets. (This is roughly the situation faced by residential customers in Upstate New York.) In other words, the DISCO has to pay a fixed amount for T&D, which does not vary with the daily pattern of loads, and on average collects ¢11/kWh for all other expenses including the cost of purchasing electricity. Since the average price paid in the spot market is ¢9.5/kWh (see Table 2), most of the ¢5/kWh for strandable assets would actually be used to purchase electricity.

Given the variability of the total cost of purchasing power in the spot market, the DISCO can lose money in spite of the substantial cushion in the regulated rate for strandable assets. The revenues received from each customer by the DISCO after paying a fixed cost of \$110.4 (0.04 x 30 x 92) for T&D has a mean of \$200/customer/summer, with a small standard derivation of #6. (All of the results are presented on a per customer basis to simplify the exposition.) The total costs of buying power in the spot market has a mean of \$198/customer/summer, with a large standard deviation of \$29. Since the variability of revenues is proportional to the variability of total sales, volumetric risk is not the primary source of risk. It is the positive correlation between daily sales and high prices that matters.

For the GENCO, the cost of purchasing electricity by the DISCO corresponds to the revenue received by the GENCO, and the GENCO faces the associated uncertainty. To some extent, the costs of generation will reduce this uncertainty because they are typically higher when the load is high. The assumptions made for these costs is that the baseload capacity needed to meet the demand of 20 kWh/day has a variable cost of ¢2/kWh and fixed cost of ¢3/kW, and peaking capacity needed to meet the additional demand of 10 kWh/day on hot days has a variable cost of ¢4/kWh and a fixed cost of ¢1/kW. The fixed cost for baseload and peaking capacity is paid everyday even if peaking capacity is idle, and the total fixed cost is \$0.7/day (20 x .03 + 10 x .01). In addition, a fixed commitment of \$0.01/kW/day is needed to cover the under-recovery of capital costs in other seasons of the year. This fixed cost reflects the fact that the spot prices in other seasons are unlikely to cover the total costs of generation.

The total generation cost has a mean of \$138, with a small standard deviation of only \$2. The reason for the small variability is that most of the costs of generation are fixed. All baseload costs are fixed, and the variable cost of peaking capacity is the only source of uncertainty.

The expressions for calculating the total costs and revenues for the DISCO and the GENCO can be written in terms of the total number of days in the summer (Nhot = 92) and the random numbers of hot days ($Nhot_t$), high prices on hot days ($NHhot_t$) and high prices on cool days ($NHcool_t$).

Revenue received by the DISCO

$$(92 - Nhot_t)20 \times 0.15 + Nhot_t \times 30 \times 0.15$$
$$-- 92 \times 30 \times 0.04$$
$$= 165.5 + 1.5Nhot_t$$

Cost of electricity in on the spot market

$$(92 - Nhot_t - NHcool_t)20 \times 0.03 + (Nhot_t - NHhot_t)30 \times 0.05 + (NHcool_t \times 20 + NHhot_t \times 30)0.3$$
$$= 55.2 + 5.4NHCool_t + 7.5Nhhot_t + 0.9Nhot_t$$

Cost of generation for a GENCO

$$92 \times 20 \times 0.02 + Nhot_t(30 - 20)0.04 + 92(20 \times 0.03 + (30 - 20)0.01 + 30 \times 0.01)$$
$$= 128.8 + 0.4Nhot_t$$

The average net earnings for the DISCO is only \$2/customer/summer with a large standard deviation of \$25. The corresponding average for the GENCO is \$60 with a standard deviation of \$28. A serious financial problem for the DISCO is that losses occur 45% of the time, while the equivalent value for the GENCO is only 1%. Both the DISCO and the GENCO have highly volatile earnings, and the DISCO faces the additional problem of frequent losses. Since the spot market causes most of the uncertainty in net earnings for both the

DISCO and the GENCO, there is a lot of potential for using forward contracts to reduce volatility. This is the issue discussed in the following section, and the objective is to identify the range of contract prices under which the DISCO and the GENCO would both be better off.

3. Opportunities for Trading Using Forward Contracts

The high variability of the net earnings for the DISCO and the GENCO provides the incentive for trading as a way to reduce uncertainty. It is assumed that both the DISCO and the GENCO are risk averse, and this is represented in the analysis by specifying a monotonic transformation of earnings into a concave "utility" function. The choice of functional form is designed to penalize losses, and therefore, to provide a clear incentive for the DISCO to reduce the high probability of negative earnings. The rationale is that if negative earnings for a summer are reported, there are likely to be adverse consequences for the DISCO such as lower stock prices, not paying dividends and higher interest rates on debt. The chosen form of utility function for both the DISCO and GENCO is:

Utility = $\text{Earnings}^{.8}$ if Earnings > 0
Utility = 1.25 Earnings if Eamings ≤ 0

The relative frequencies of the levels of utility are shown in Figure 4 for the DISCO, and they are highly skewed to the left because of the high proportion of losses. In contrast, the distribution of the utilities for the GENCO in Figure 5 is only slightly skewed to the left. The mean utility for the GENCO is 25.75, which is equivalent to guaranteed earnings of $58.01. Since the mean earnings for the GENCO is $59.73, the GENCO is willing to give up (59.73 – 58.01) = $1.72 in the mean earnings to avoid risk.

The corresponding mean utility for the DISCO is –5.31, which corresponds to guaranteed earnings of $-4.25. Hence, a certain small loss is equivalent to the risky mean earnings of $2.32. The DISCO is willing to give up (2.32 + 4.25) = $6.57 on average to avoid risk, which is substantially more than the GENCO. This reflects the fact that the DISCO is more financially vulnerable than the GENCO because losses are much more likely to occur.

Before evaluating the benefits of making forward contracts for a summer, some important qualifications should be made. There are two underlying assumptions being made in the following analysis. The first is that both the DISCO and the GENCO have the same knowledge about the spot market. In other words, the characteristics described in Section 2 represent the beliefs of both the DISCO and the GENCO about the next summer and determine their willingness to execute a forward contract. The second assumption is that neither the DISCO or the GENCO can influence the spot market by making a forward contract. If high prices are caused by using market power, Wolak (2001) has argued that holding firm
contracts

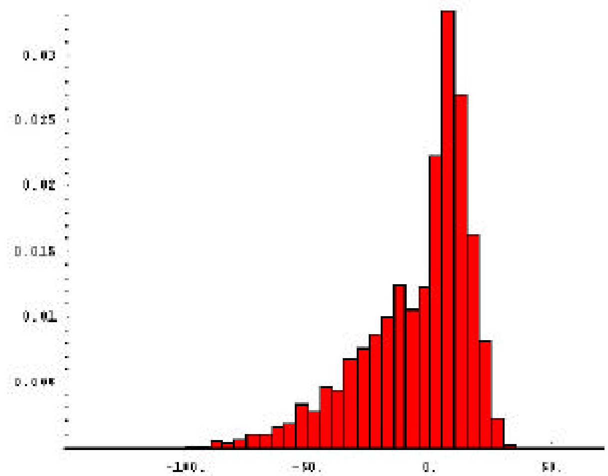

Figure 1. The relative frequencies of utility for a DISCO (dollars/customer/summer)

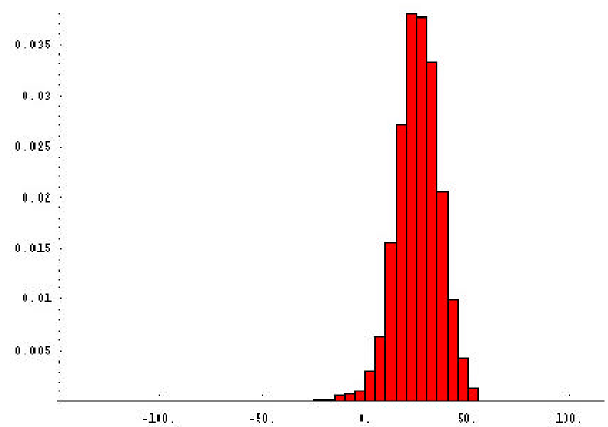

Figure 2. The relative frequencies of utility for a GENCO (dollars/customer/summer)

would limit this behavior and lower average prices. Hence, this important interaction between spot price behavior and forward contracts is not addressed in this paper.

The chosen form of contract is to specify a fixed charge for capacity in $/day and a variable charge for energy in ¢/kWh. This type of contract is shown by Wu, Kleindorfer and Zhang (2000) to be optimum under specified conditions. In fact, under their specifications, the optimal contract for the supplier is to set the variable cost equal to the marginal cost of generation (¢4/kWh in this example), and to set the capacity charge as high as the market will bear. This is consistent with the rationale for charging a high entry fee and a low price followed by a perfectly discriminating monopolist (See Oi (1971) and Brown and Sibley (1986)). However, under the specifications of the spot market in this paper, the conventional strategy is not optimal because of the positive correlation between prices and load. In fact, a wide range of different contracts are virtually identical in terms of the gains in expected utility for the DISCO and the GENCO.

For any specified value of the variable charge, it is possible to determine the range of values of the fixed charge under which both the DISCO and the GENCO get higher utility from trading compared to buying and selling in the spot market. The trading opportunities for five different variable charges are summarized in Table 3. The variable charges range from ¢0/kWh (the DISCO pays a fixed charge only and energy is free) to ¢15/kWh (the DISCO receives a fixed payment and the GENCO the revenue paid by customers). Even though a wide range of contracts are acceptable to both parties, the increases of expected utility for equal gain vary very little from 2.07 to 2.27. The maximum gain is for ¢12/kWh, although the difference from ¢15/kWh is trivially small. The variable charge of ¢9.78/kWh corresponds to a fixed price contract with no fixed charge. This fixed price is preferred by the DISCO to the lower average price of ¢9.54/kwh in the spot market because this latter price has a large standard deviation of ¢1.28/kWh. In general, average prices under the acceptable contracts are higher than the spot market average. The exceptions correspond to situations in which most gains in expected utility go to the DISCO (see Table 3).

Table 4 summarizes the means and standard deviations of the total cost of purchasing electricity under the different contracts. In all cases, the variability of total cost is much smaller than that variability in the spot market. The corresponding means and standard deviations of earnings are summarized in Table 5 for the DISCO and the GENCO. Earnings for the GENCO are perfectly hedged at ¢4/kWh, and these earnings become more uncertain as the variable charge increases from ¢4/kWh to ¢15/kWh. The opposite happens for the DISCO, and earnings for the DISCO are perfectly hedged at ¢15/kWh. Although all of the contracts in Tables 3-5 are preferable to purchasing power on the spot market for both the DISCO and the GENCO, average earnings are always negative for the DISCO, and losses occur most of the time. Losses never occur under the contracts for the GENCO.

For contracts with variable charges greater than ¢9.78/kWh, the fixed charge is negative, which may appear to be an anomaly. One way to interpret this type of contract is to consider an equivalent form with different variable charges for baseload power and peaking power. For example, if the variable charge of ¢12/kWh is treated as the price of peaking power, the corresponding price for baseload power is 12 - 50/20 = ¢9.5/kWh, where the fixed charge of ¢50/day is allocated to the constant demand for 20 kWh of base load power. Looked at this way, a

Table 3. Trading Opportunities for Different

	Variable Charge for Use (¢/kWh)				
	0	*4*	*9.78*	*12*	*15*
1. Min. Fixed	2.13	1.23	-0.07	-0.57	-1.24
Average Price	9.47	9.47	9.47	9.47	9.47
DE [Utility] for DISCO[3]	7.37	7.82	8.27	8.34	8.35
2. Fixed Charge for Equal Gain	2.19	1.3	0	-0.5	-1.17
Average Price Paid	9.75	9.77	9.78	9.78	9.78
DE [Utility]	2.07	2.17	2.26	2.27	2.27
3. Max. Fixed Charge	2.22	1.32	0.02	-0.48	-1.15
Average Price Paid	9.85	9.86	9.87	9.87	9.87
DE [Utility] for GENCO[3]	2.74	2.84	2.9	2.9	2.89

[1] Fixed Charge in $/day

[2] Average price in ¢/kWh is the combined varible charge + fixed charge/average use (22.5 kWh/day).

[3] Increase in the expected utility compared to purchasing (or selling) all power on the spot market (E[Utility] = -5.31 for the DISCO in the spot market, and 25.75 for the GENCO).

Table 4. Total Cost of Purchasing Power Under Different Contracts.

Variable Charge	Fixed Charge	Cost of Power ($/summer)	
¢/kWh	$/day	Mean	St. Dev.
0	2.19	201.86	0
4	1.30	202.15	1.69
9.78	0	202.42	4.13
12	-0.50	202.46	5.07
15	-1.17	202.47	6.34
Spot Market		197.72	29.39

Table 5. Earnings and Utility Levels Under Different Contracts.

Variable Charge	Fixed Charge	DISCO		
		Earnings ($)		Utility
¢/kWh	$/day	Mean	St. Dev.	Mean
0	2.19	-1.83	2.73	-3.24
4	1.30	-2.11	4.65	-3.14
9.78	0	-2.39	2.21	-3.05
12	-0.50	-2.43	1.27	-3.04
15	-1.17	-2.43	0	-3.04
Spot Market		+2.32	25.16	-5.31
Variable Charge	Fixed Charge	GENCO		
		Earnings ($)		Utility
¢/kWh	$/day	Mean	St. Dev.	Mean
0	2.19	63.88	1.69	27.81
4	1.30	64.17	0	27.92
9.78	0	64.44	2.44	28.01
12	-0.50	64.48	3.38	28.02
15	-1.17	64.49	4.65	28.02
Spot Market		59.73	28.19	25.75

contract that pays more for baseload power than peaking power (i.e. has a positive fixed charge) is an anomaly. A price of ¢9.5/kWh for baseload power is still substantially higher than ¢6/kWh, which was the fair price anticipated by regulators (see the discussion in Section 2). The objective of the next section is to show how weather derivatives can be used to get lower prices for baseload power and to offset the greater uncertainty associated with the corresponding higher prices for peaking power. These combined contracts are preferable to the ones discussed in this section because they provide more accurate price signals when the load is high on hot days.

4. A Role for Weather Derivatives.

The basic problem facing the DISCO in the spot market is that the daily cost of purchasing electricity can be much higher than the revenue received from customers. Getting a fixed price for electricity is an attractive feature of the contracts discussed in Section 3. However, once the price has been fixed in a contract, any incentives to reduce load when prices are high in the spot market are dissipated. It is quite possible that actually paying the high price of ¢30/kWh would lead to reductions of load even though demand is inelastic at ¢15/kwh. Considering contracts with high prices for peaking power and low prices for baseload power makes sense because 1) the high prices affect only a small part of the load (on average 2.5 kWh/day versus 20 kWh/day of baseload power in the example), and 2) the high price for peaking power gives a real incentive for load reductions and increased supply on hot days. In addition, it is easier to hedge against these high prices because they are perfectly correlated with hot days. In the spot market, high prices can occur on cool days as well as on the majority of hot days, and as a result, the weather option can not provide a perfect hedge against high prices. In contrast, the high prices under the contract are paid for peaking power on every hot day and never paid on cool days.

All of the contracts presented in Section 3 can be written as linear functions of the number of hot days. This is exactly the same functional form as the net revenue for the DISCO and for the cost of generation for the GENCO (see Section 2). Consequently, under a contract the net earnings of the DISCO and the GENCO are also linear functions of the number of hot days. If the contract is specified with a fixed charge of $F/day and a variable charge of ¢V/kWh, then net earnings can be derived from the expressions at the end of Section 2 and shown to have the following forms:

Net earnings of the DISCO

$$= (165.5 - 92F) + (1.5 - V/10)NHot_t$$

Net earnings of the GENCO

$$=(92F - 128.8) + (V/10 - 0.4)NHot_t$$

where $NHot_t$ is the number of hot days in summer t.

The price ¢V/kWh is the price of peaking power, and the corresponding price of baseload power is ¢(V – 5F)/kWh. Consider a contract under which the price of peaking power is equal to the high price in the spot market, implying V = ¢30/kWh. This price would give a strong signal on hot days to buyers to reduce demand and to generators to increase supplies. Using the procedures described in Section 3 to derive the fixed charge for equal gain, the value is F= --$4.55 / day, which is equivalent to a baseload price of ¢7.2/kWh. This is still higher than the "regulated" rate of ¢6/kWh, but price structure is much closer to the actual costs in the spot market than the

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corresponding structure for the "best" contract in Table 3, with V = ₵12/kWh. However, the gain in expected utility when V = ₵30/kWh is only 2.03 compared to 2.27 when V = ₵12/kWh, because there is more risk when V = ₵30/kWh (the standard deviations of net earnings increase by factors of 5 and 3 for the DISCO and the GENCO, respectively). Hence, the contract with V = ₵30/kWh is not a desirable alternative for either the DISCO or the GENCO.

Consider now a financial option which pays out when the number of hot days is above (or below) a "strike" value. Payouts above the strike of StrikeC define the following call option:

$$\text{Payout} = \text{Max}[0,(\text{Nhot}_t - \text{StrikeC})\text{TickC}]$$

where TickC is the payout per hot day. The corresponding put option for hot days is:

$$\text{Payout} = \text{Max}[0,(\text{StrikeP} - \text{Nhot}_t)\text{TickP}]$$

Both of these options would have a premium, which would be determined by the chosen levels of the strike value and the size of the tick.

If buying a call option is combined with selling a put option to form a collar option, it is possible to specify an option that requires no premium. The owner of this option gets paid if there are a lot of hot days in the summer, but has to pay others when there are only a few hot days. Consequently, it is possible to use this type of collar option to hedge against the total cost of peaking power under a contract. In fact, for the simple market used in this analysis, it is possible for both the DISCO and the GENCO to hedge earnings perfectly.

Since the earnings of the DISCO and the GENCO are both linear functions of Nhot_t under a contract, choosing the values TickC = TickP = (V/10 – 1.5) for the DISCO and (0.04 – V/10) for the DENCO would stabilize earnings. The perfect hedge corresponds to StrikeC = StrikeP = 23, and in this situation, earnings are constant and equal to the level computed for the average number of hot days (i.e. $\text{Nhot}_t = 23$).

For every forward contract, collar options can be specified for the DISCO and the GENCO to form perfect hedges of earnings. There would be costs associated with these transactions, but these costs would be determined to a large extent by factors outside the utility industry. In other words, weather options could be traded with people who do not necessarily have anything to do with the energy industry. Summer resorts would be one example of a sector which might be willing to sell call options and buy put options to balance the requirements of a DISCO. Hot weather is financially good for the resorts and bad for the DISCO. It may also be true that the benefits of hedging are insufficient to justify the transaction costs for the GENCO. Hence, it is not clear what the net demand for call and put options would be from the DISCO and the GENCO. This topic will be explored further in future research. For the remainder of this section, collar options which provide perfect hedges of earnings and have no transaction costs will be considered. This approach provides an upper bound to the benefits that can be obtained by combining contracts for purchasing power with collar options for hot days.

The financial effects of different combinations of forward contracts and options are summarized in Table 6. The contract is chosen to give the same average price as the spot market so that differences among combinations relate to their riskiness only. Combinations 1 and 2 imply purchasing on the spot market, and Combinations 3 and 4 use contracts exclusively. Combinations 2 and 4 also use a collar option. Using the spot market with no hedging is risky in terms of costs of purchases and the earnings of the DISCO and the GENCO (Combination 1). Using the collar option reduced the riskiness of earnings a little, but the average utility for the DISCO is still negative even though the average earnings is positive. (Note that it would be possible to find a better collar option for this situation, but it still could not form a perfect hedge of high prices in the spot market.) Taking a contract reduces risk and increases average utility substantially for the DISCO and slightly for the GENCO (Combination 3). Adding the collar option in Combination 4 reduces the risk to zero for both the DISCO and the GENCO, but once again the largest improvement in average utility

Table 6. The Effects of Different Combinations of Contracts[1]

Combination Number	Percent Covered[2] Peakin	Percent Covered[2] Baseload	Collar Option[3]	Cost of Purchases ($) Mean	Cost of Purchases ($) St. Dev.
1	0	0	No	197.72	29.39
2	0	0	Yes	197.72	29.39
3	100	100	No	197.36	12.68
4	100	100	Yes	197.36	12.68

Combination Number	DISCO Earnings ($) Mean	DISCO Earnings ($) St.	DISCO Utility Mean	GENCO Earnings ($) Mean	GENCO Earnings ($) St.	GENCO Utility Mean
1	2.32	25	-5.31	59.73	28.2	25.75
2	2.39	22	-4.25	59.73	22	26.04
3	2.67	6.3	0.95	59.38	11	26.16
4	2.67	0	2.2	59.38	0	26.24

[1] The purchase contract is ¢30/kWh for peaking power

[2] Percentage covered by the contract, and the

[3] Using a collar option for all purchases (Yes) or none

accrues to the DISCO. The overall conclusion is that combining a firm contract with a collar option is a major benefit to the DISCO (average utility increases by 7.5 from Combination 1 to Combination 4) and a modest benefit to the GENCO (average utility increases by 0.5). The main benefit of the collar option is to provide the DISCO with a hedge against a risky contract with a high variable charge of ¢30/kWh.

A problem with the results in Table 6 is that the increase of average utility of the GENCO is smaller than the gains made with the contracts discussed in the previous section (see Table 3). Consequently, Combination 4 in Table 6 is not going to be attractive to the GENCO because most of the gains go to the DISCO. However, it is possible to find the characteristics of a combination contract corresponding to equal gains for the GENCO and the DISCO. The plots in Figure 3 show the gains from trading using a variable charge of ¢30/kWh. The dark symbols correspond to the gains for a combination contract with the collar option, and the gray symbols are the gains without the collar option. The difference between these two situations is hard to distinguish for the GENCO, but the gains from the collar option are obvious for the DISCO. The increase of expected utility for equal gain is 2.28, which is slightly higher than the gains shown in Table 3 for firm contracts without a collar option. However, hedging with a collar option would also improve the contracts in Table 3. The implication of having a perfect hedge for earnings is that the DISCO and the GENCO are indifferent to whether the variable charge is high or low, as long as the fixed charge is adjusted accordingly to make the overall level of earnings the same. Making the collar option available extends the range of contracts that are acceptable, and in particular, makes it feasible to specify contracts with a high variable charge for peaking power.

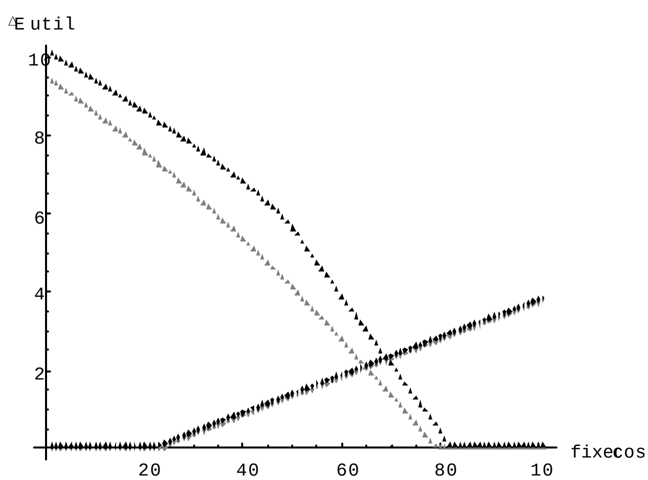

Figure 3. The Gains from Trade with (black) and without (gray) a Collar Option for Hot Days.

5. Summary and Conclusions

The objective of this paper is to show how weather derivatives can be used to strengthen the position of buyers of electric power in restructured markets for electricity. The underlying assumption is that uniform price auctions tend to exhibit highly volatile price behavior, particularly in the summer on hot days when the load for air conditioning is high. The frequency and size of price spikes are closely related to both the total cost of purchasing power in spot markets and the riskiness of these costs. The main reason for this is that high prices generally occur when load is also high. Consequently, price risk and volumetric risk are positively correlated. If price spikes are larger or more frequent than expected, buyers may be put under substantial financial pressure while suppliers benefit from higher profits. In these circumstances, there are strong incentives for buyers to use forward contracts to buy electricity at predetermined prices, and by doing so, to reduce risk. However, suppliers have less to gain from these contracts, and as a result, are likely to extract relatively favorable contracts from buyers.

The approach taken in Section 2 of this paper is to specify a simple empirical model of an electricity market, and to compare the effects of this market on a representative Distribution Company (DISCO), buying electricity for customers, and a Generation Company (GENCO), supplying electricity to the market. The price behavior in the spot market is independent of the behavior of the representative DISCO and GENCO. High prices are likely to occur on hot days, but they may also occur on cool days in the summer. Load is high on hot days and low on cool days, and the total number of hot days is random. For any summer, uncertainty about the total number of hot days is the major source of riskiness about the total cost of buying electricity in the spot market.

It is assumed that the DISCO is operating in a regulated transition period and receives a fixed price for all sales of electricity. The costs of the DISCO are a fixed cost of operating the transmission and distribution system and the variable cost of purchasing power. Even though the rate paid by customers contains a large component designated for strandable assets, the DISCO still loses money over 40% of the time if all purchases are made in the spot market. By specifying a concave utility function that penalizes losses, it is possible to capture the financial predicament faced by the DISCO. Although average earnings are slightly positive, the DISCO would actually prefer to have a small, certain loss to avoid the possibility of major losses in the spot market when the number of hot days is unusually large.

For the GENCO, it is assumed that most of the costs of generation are fixed, and the only source of uncertainty about costs is the relatively small, variable cost of

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peaking power. Since the prices in the spot market favor suppliers by assumption, the uncertainty about prices in the spot market is easier to deal with compared to the DISCO. For the GENCO, it is extremely rare for losses to occur, and the gains from reducing risk are relatively small.

The analysis in Section 3 shows how forward contracts for buying power can benefit both the DISCO and the GENCO. It is assumed that both parties must benefit if a trade is to occur. Even though the potential gains from trade are much larger for the DISCO, it is argued that the GENCO will be reluctant to trade if the benefits to the GENCO are small. Hence, an assumption of equal gains is used to determine the specific prices for a contract.

Each contract is composed of a variable charge for each unit of energy sold and a fixed charge. For the best contracts with the largest gains in benefits, the average price paid for electricity is always about ¢9.78/kWh, although the variable charge can vary from ¢10/kWh to ¢15/kWh. At ¢15/kWh, the earnings of the DISCO are riskless, and at ¢4/kWh, the earnings of the GENCO are riskless. Hence, the best contracts represent a balance between these two riskless extremes. Setting the variable charge below ¢10/kWh or above ¢15/kWh leads to noticeably smaller gains in benefits.

There are two practical deficiencies with the set of contracts for power that are acceptable to both the DISCO and the GENCO. First, the resulting average price is higher than it was in the spot market (¢9.54/kWh), and this latter price was considered to be much higher than it should be in a competitive market. Hence, the contract deals with the problem of risk but not with the problem of high prices. Second, the contract fixes a price that may be higher than it should be on average but is still much lower than the high prices paid in the spot market. Even though the price spikes are the primary cause of the financial problems for a DISCO in the spot market, paying a lower price when price spikes occur undermines the market incentives to reduce demand and increase supply. Hence, forward contracts may effectively neutralize the forces needed to bring discipline to the market and lower prices in the future.

The situation at the end of Section 3 is closely related to the recent events in the Californian market. High prices in the spot market make it possible for suppliers to get attractive forward contracts for electricity. Buyers will still pay prices that are higher than they would be in a truly competitive market. This is a genuine predicament for regulators. It may be true that having a large proportion of demand covered by forward contracts will lower spot prices, as many people have argued in California. However, these low prices will not benefit customers if high prices are still being paid under the contracts. What is needed is a way to hedge against paying high prices without losing the incentives that high prices provide in a market. The goal of regulators should be to help customers maintain financial viability in spite of paying high prices occasionally. This strategy is very different from the approach favored by the Federal Energy Regulatory Commission (FERC) and many state regulators. Current regulatory interventions, such as the soft cap auction proposed by the FERC for California in December 2000, try to reduce the effects of high prices. In contrast, the discipline of a market implies that suppliers who try to be greedy by offering capacity at high prices should lose market share. Making the load responsive to high prices, for example, is one way to bring more discipline to a market.

The main contribution of this paper is to show how weather derivatives can be used to hedge against high prices. The best contracts for trading identified in Section 3 all have variable charges that are well below the high prices that occur occasionally in the spot market. If a higher variable charge is specified, with a corresponding reduction of the fixed charge, the additional uncertainty of earnings for the DISCO and GENCO reduces their mutual gains. Nevertheless, these contracts can be interpreted as having a high price for peaking power and a low price for baseload power. Setting the variable charge equal to the high price in the spot market (¢30/kWh), for example, implies that the corresponding price of baseload power is ¢7.2/kwh, which is getting closer to a fair price. If the price for baseload power was set to ¢6/kWh, the corresponding variable charge for peaking power would be ¢39.6/kWh. Under these contracts, most of the demand (20 kWh/day) is charged at the low baseload price. This is a fixed cost for the summer. The payments for peaking power are made at the high price and are very variable because this demand is proportional to the number of hot days. In the spot market, the high prices are not perfectly correlated with the number of hot days. In fact, the contract will pay high prices more often than the spot market. However, the contract also protects the baseload demand from these prices. Hence, the uncertainty under the contract is associated with a larger number of days but a much smaller level of demand (2.5 kWh/day on average). The net effect is that the variability of the total cost of purchases is lower under the contract than it is in the spot market.

Since the uncertainty of earnings in the specified market for both the DISCO and the GENCO is perfectly correlated with the number of hot days, it is possible to specify a perfect hedge for earnings using a weather option. This procedure is described in Section 4. A collar option pays the DISCO if the number of hot days is higher than average, and the DISCO pays if there are fewer hot days than average. The GENCO follows exactly the opposite strategy. By eliminating the risk, the range of acceptable contracts to the DISCO and the GENCO is extended to include variable charges above

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¢15/kWh. Contracts can be designed to pay an appropriate high price for peaking power (and derive the corresponding price for baseload power) or to pay a fair price for baseload power (and derive the corresponding price for peaking power).

Using weather options also increases the number of participants in the market. In general, the lack of liquidity is a major problem in forward markets for electricity because there are regional differences in prices and different sources of supply are not perfect substitutes. Hence, there are potential advantages from having more participants in the market as a way to increase liquidity. Since it is more likely that a DISCO will use weather options than a GENCO, economic sectors that benefit from hot summers, such as summer resorts, may be willing to sell appropriate collar options. Identifying the requirements for this type of market and the effectiveness of different forms of options are topics for future research. It should be noted, however, that the existing structure of options for cooling-degree-days is not very appropriate for hedging in electricity markets.

A final point, which is very important for policy, is that the proposal made in Section 4 to combine contracts for power with weather options does not solve the problem of high prices in the short run. It is highly unlikely that a GENCO will settle for a contract with a lower average price than the spot market even if this latter price is much higher than competitive levels. The advantage of the combination contract is that the market incentives of paying high prices on hot days are not lost. If demand is reduced on a hot day, the savings to a DISCO (or to customers if they pay actual costs) will be relatively large. Making hot days synonymous with high prices will make it easier for customers to understand how the market works and when reductions in load are needed. It will also provide better security for recovering investments in load response.

At the present time, price spikes are treated by many regulators as an aberration. Their goal is to suppress price spikes. A better strategy is to insure against the financial losses associated with price spikes. Combining weather options with forward contracts is an effective way to hedge against high prices. More importantly, this strategy strengthens the powerful forces that make markets work competitively. Even in a truly competitive market, it will be expensive to meet high loads on hot days. Customers or their agents should be made more aware of this fact, and, at the same time, be protected from the financial consequences. The next step for research is to determine how well this strategy works with real data on load, prices and temperature.

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