Incentives for New Investment in a Deregulated Market for Electricity*

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Contents

Abstract

All decisions about investments in new generation, transmission, distributed energy resources and load management are based on expectations about future market conditions. This paper develops an analytical framework for evaluating forward contracts and investment decisions under the assumption that firms are risk averse. A fixed price/fixed quantity delivery contract forms the basis for the portfolio of a Distribution Company (DISCO). It is supplemented by a two-part contract for peaking capacity (A variable charge for real energy delivered and a fixed charge for capacity). The prices and quantities of these contracts are optimized to provide an equilibrium solution between the DISCOs and the Generating Companies (GENCOs) with equal market power for each side of the market. Additional purchases of electricity may be made in a spot market that is characterized by infrequent price spikes during the summer months. These price spikes make the spot market very risky for a DISCO because customers pay a fixed regulated rate to the DISCO. Using a set of realistic assumptions about price behavior in the spot market, the results show that the optimum quantity of capacity contracted by the DISCO is substantially above the average on-peak load for the summer.

From the perspective of a potential investor in new generating capacity, the net revenue from a peaking contract is shown to be less than 30% of the level needed to justify the investment. The additional annual premium needed to build 1000MW of new peaking capacity is shown to be much smaller than the equivalent cost of two alternative policies that attempt to make the market give the "right" signals for a new investment. The first policy is to ensure that the annualized capital cost of new peaking capacity can be recovered by increasing the price paid for availability in an ICAP (capacity) market. This higher price is paid for all capacity in the ICAP market and not just for the new investment. The second policy is to allow higher price spikes in the spot market, keeping the average spot price constant. The additional risk faced by a DISCO with higher and more volatile spot prices puts a GENCO in a strong position to extract a substantial risk premium from the DISCO above the expected spot price. This risk premium leads to an increase in the total cost paid by a DISCO when price spikes are allowed. However, the additional cost of investing in new peaking capacity is less than half the corresponding increased cost using higher ICAP payments.

Key Words: investment incentives, two-part contract, price spikes, risk averse, ICAP

JEL classification: C0; G0; L0; L5; L9; Q4

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1 Introduction

In both regulated and deregulated (or restructured) markets for electricity, the supply system must meet standards of reliability as well as generate enough real energy to meet the current level of load (demand). System security determines how to use existing generators in real time to cover an unexpected loss of equipment, such as a generator. System adequacy determines the level of generation and transmission capacity needed to meet expected demand in the future.

The real energy purchased by customers is a private good, but maintaining reliability on a network is a public good (Mount, Schulze and Schuler, 2003). Consequently, the need to specify an explicit reliability standard for system adequacy will still remain in a deregulated market, but there is no built-in way to ensure that investment will be sufficient to meet this standard. Since market forces determine investment behavior in a deregulated market, market participants decide on their own whether or not they want to build a new facility. Oren(2002) argues that system adequacy can be treated as a private good if the reserve margin is specified as a fixed proportion of the maximum load. However, this still implies that there is no guarantee that the amount of installed capacity in a deregulated market will be sufficient to maintain system adequacy without some oversight and possible intervention by the system operator and/or by regulators. The focus of this paper is on generation capacity, and the transmission capacity is treated as fixed. In reality, both types of capacity interact with each other to determine whether or not system adequacy in a load pocket, for example, meets the NERC standard. An important goal for future research is to extend the methods to consider investment in transmission.

The procedures used by NERC to identify a future shortfall of generation capacity are similar in both regulated and deregulated markets. The main difference is in the response to a potential shortfall of capacity. Under traditional regulation, having a guaranteed rate of return on a prudent investment provided a sufficient incentive to ensure that utilities would be willing to build the needed capacity. In fact, regulators were typically more concerned about the Averich-Johnson effect and having too much capacity built rather than too little capacity. Since there is no guaranteed rate of return in a deregulated market, investors' expectations about the spot market determine directly, or indirectly through forward contracts, whether a particular investment is worthwhile. Without a guaranteed rate of return, financial risk becomes a central issue for investors. Unfortunately, regulators in the USA have probably exacerbated the financial risk faced by investors in deregulated markets by changing the market rules and, more importantly, market outcomes (see Bushnell (2003) for a general discussion of this topic, and Mount and Lee (2003) for an analysis of the Californian market during the "crisis" in 2000/01).

The forward prices (the price at the current trading date for delivery at a specified future date) of electricity and fuels are the basic inputs for evaluating an investment in generation capacity. Although economic theory can determine the prices of standard financial derivatives for many commodities, such as stocks and bonds, this is not the case for electricity. The first reason is that part of the risk, such as the regulatory risk, cannot be diversified, and therefore, standard procedures, like using the Black-Scholes formula, are no longer applicable. A second reason is that electricity is effectively non-storable, and as a result, standard arbitrage-based methods of determining forward prices are also not applicable. For storable commodities, the "cost-of-carry" is the key factor linking the forward price to the spot price, and in equilibrium, the forward price is equal to the spot price plus the cost of storage. For electricity, however, the quantities delivered on different dates are effectively different commodities, and the forward price curve for future delivery dates corresponds to the expectation of the corresponding spot price for each delivery date plus a risk premium. Consequently, forward curves for electricity are influenced by expectations about fuel prices and tend to exhibit distinct seasonal patterns reflecting the level of load.

Since the standard analytical procedures for calculating forward prices are not appropriate for electricity, one possible alternative approach is to use the observed relationship between spot and forward prices to estimate the risk premium. Unfortunately, there is no established source of price discovery for the forward price of electricity that is equivalent to the futures market for natural gas operated by the New York Mercantile Exchange (NYMEx) at Henry Hub. A fundamental complication for electricity is that the effects of congestion on the transmission system and of different regulatory rules in different regions make spot price behavior much more regionally idiosyncratic compared to natural gas. Consequently, it is infeasible for pricing electricity derivatives to rely on prices in a national market at one location as a primary source of price discovery for all locations. For example, NYMEx trades financial swap options (contracts for the cost-of-differences) for electricity at three different locations in New York State, but it is unlikely that these prices would provide effective hedges for prices in PJM and New England. Until recently, the volume of electricity trading on public exchanges was limited, and this lack of liquidity made these markets unreliable as a source of price discovery. Most trading was, and continues to be, over-the-counter, and public information about the forward price curve for electricity is often unreliable and is simply not available for many regions of the country.

Due to these difficulties, there is relatively little literature addressing the issue of how to price derivatives in electricity markets. Routledge, Seppi, and Spatt (1999) determine an equilibrium price for an electricity contract by linking the markets for natural gas and electricity (i.e. analyzing the spark spread) and using the fact that natural gas can be stored or converted into electricity. Wu, Kleindorfer and Zhang (2000) specify a contract arrangement between one Seller and one or more Buyers when the product delivered under the contract comes from a non-scalable, capital-intensive production facility. In their model, Buyers and the Seller negotiate contracts in advance, and on any day, the Seller can sell in the spot market any electricity that is not used by the Buyers, or buy electricity in the spot market if the spot price is lower than the production cost. This type of bilateral contract is a two-part contract. The first part is a reservation cost per unit of capacity, and the second part is an execution cost or price per unit of product purchased. Using a von-Stackelberg game with the Seller as the leader, they show that the optimal contract for the Seller is to set the execution cost equal to the true marginal cost, and to set the reservation cost as high as the Buyer can bear. Mount and Yoo (2002) show how weather derivatives can be used to hedge contracts that specify high prices on hot (high load) days, and therefore, preserve important market signals.

Bessembinder and Lemmon (B&L, 2002) present an equilibrium model of the spot and forward prices that applies when these prices are determined by industry participants and the net position of the market is always zero (i.e. there is no speculation by traders). Assuming that the participants are risk averse and represented by a mean-variance framework, B&L obtain closed form solutions for the equilibrium forward price and for the optimal forward position. Using this model, the equilibrium forward price has a higher risk premium in the summer months when the expected market demand and the price volatility are highest. They show that this prediction is confirmed by data from PJM and California (prior to the crisis period). Siddiqui (2002) uses a similar mean-variance framework to consider markets for reserve capacity as well as for real energy and shows that reserves can be treated like a financial derivative and used to manage risk.

All of the papers cited in the previous paragraph deal with the financial risk associated with the uncertainty of future prices. At the present time, the effects of regulatory risk, however, are likely to increase the risk premium for electricity. For example, it is difficult at the present time for investors to predict the effects of establishing a new Regional Transmission Organization (RTO) in the Midwest. The underlying implication is that observed forward prices may differ substantially from the values implied by simple economic models. This was definitely the case in California during the crisis (Mount and Lee), but, as mentioned above, B&L find that the forward prices before the crisis were consistent with their theoretical model. In addition, Lucia and Schwartz (2002) show that the risk premium in the Nordic market follows a similar seasonal pattern to the one derived by B&L. In the Nordic market, the prices have been relatively stable and free from the type of disruptions experienced in the USA.

The basic conclusions relating to system reliability are (1) it is important to have public information about forward prices as well as spot prices, particularly when major regulatory changes are likely to occur, and (2) uncertainty about the effects of regulatory rules, such as the Automatic Mitigation Procedures (AMP) used in the Northeast, is likely to increase to the risk premium for electricity and make it harder and more expensive to meet reliability standards.

There are indications that shortages of generation capacity may occur relatively soon in the Northeast. For example, a recent study of electricity supply in New York City predicts that an additional 2600MW of capacity will be needed by 2008 (New York City Energy Policy Task Force, 2004). The main objective of this paper is to provide an analytical framework for evaluating this type of problem. The approach taken is similar to the one used by B&L, but in our model, the mean-variance framework is replaced by a representation of risk that is more consistent with economic theory. As Jarrow and Zhao (2003) explain, a mean-variance framework is not an appropriate model when the distribution of returns is skewed, and skewness is an important feature of deregulated electricity markets due to the presence of price spikes. In particular, our model exhibits aversion to financial losses, and as a result, the framework identifies the basic asymmetry of risk faced by buyers and sellers when price spikes occur in the spot market.

The uncertainty of both price and load (volume) are modeled explicitly, and it is assumed that any regulatory risk is incorporated into the probability density functions for price and load. In this respect, our model has the same limitation as the other models in the literature. Since regulatory risk is likely to increase the risk premium for electricity, our results should be treated as a lower bound on the cost of maintaining system reliability when the financial incentives for investment in the spot market are inadequate. Determining how well our predicted forward prices explain observed forward prices will be a subject for future research.

If a projected shortfall in generation capacity is identified in a region (i.e. standards of system adequacy will not be met in the future given current information on investment and retirements), the most direct way of correcting the problem is to request bids for building the additional capacity. This request could be made by a system operator and/or by regulators, and the cost of the contracts would eventually be allocated to the Load Serving Entities (LSE) in the region. This type of direct intervention by regulators is considered by many people to be inconsistent with the basic objective of relying on market forces to make decisions in a deregulated market. Largely in response to this type of reasoning, regulators in the Northeast have been considering alternatives to direct contracting.

One alternative to direct contracting has already been implemented in New York State, and it involves augmenting payments to generators in the Installed Capacity (ICAP) auction. The current rule in New York State requires each LSE to buy generation capacity in the ICAP auction to cover their forecasted peak load plus an 18% margin. Any LSE that fails to cover this margin must pay a very large penalty. Similar rules govern the ICAP markets in PJM and New England. Sellers of ICAP receive the revenues from the auction and, in return, have an obligation to submit offers into the Day-Ahead Market (DAM). In other words, the ICAP auction provides assurance that generators will be available in the DAM and that standards of system adequacy will be maintained in the short run (i.e. a few months ahead).

The modified ICAP auction specifies a demand curve that is calibrated to pay the annualized capital cost of 1MW of new peaking capacity at the "ideal" level of capacity needed to maintain system adequacy (Reeder, 2002). The clearing price will be higher (lower) if the total capacity offered is less (more) than the ideal amount. The narrow objectives of the modification are to stabilize revenues for generators in the ICAP auction and to extend the auction further into the future. The broad objectives are to encourage new investment and discourage retirements when a capacity shortage is projected in the future.

A second alternative to direct contracting corresponds to the approach taken in Australia. Partly in response to the Californian crisis, regulators in the USA have imposed relatively low price caps in the spot market and implemented other Automatic Mitigation Procedures (AMP). In Australia, the regulatory environment is very different and the price cap is about seven times higher than it is in the Northeastern markets ($10,000A/MW versus $1000US/MW). In general, higher price spikes imply higher returns for peaking capacity in the spot market, but the overall average price may be higher or lower. The evidence from Australia suggests that deregulation has reduced the average price even though very high price spikes do occur (NECA, 2004).

The first part of this paper (Section 2) develops an analytical framework for evaluating forward contracts under the assumption that firms want to avoid financial losses (i.e. firms are risk averse). A fixed price/fixed quantity contract, similar to the standard contract-for-differences traded on the New York Mercantile Exchange, forms the basis for the portfolio of a Distribution Company (DISCO). It is assumed that the DISCO is in a transition phase of deregulation, and the customers of the DISCO pay a fixed regulated rate for electricity. The DISCO faces volume risk, because load is stochastic, and price risk for purchases in the spot market. The fixed contract is supplemented by a two-part contract for peaking capacity (A variable charge/MWh for real energy delivered and a fixed charge/MW for capacity).

The prices and quantities of the two-part contract are optimized to provide an equilibrium solution between the DISCOs and the Generating Companies (GENCOs) with equal market power for each side of the market. Additional transactions may be made in the spot market that is characterized by infrequent price spikes during the summer months. These price spikes imply higher profits for a GENCO but they make the spot market very risky for a DISCO. In our analysis, the behavior of spot prices is exogenous and is not affected by the positions of the DISCO and GENCO in the forward market.

The second part of the paper (Section 3) evaluates an investment decision for 1000MW of new peaking capacity. The assumption is that a potential new entrant into the market must receive a high enough rate of return to cover the inherent risk in the electricity market and make the investment equivalent to a stable rate of return in the bond market. It is assumed that the investor already has a forward contract for fuel but will need to have a long-term forward contract for electricity to secure financing. The terms of this forward contract will be affected by prices in the spot market. Given the asymmetry of risk in the market, an investor can get a high premium in a forward contract from a DISCO when price spikes are high and/or frequent. Under the assumptions made about spot prices, a forward contract for peaking capacity will provide less than 30% of the rate of return needed to justify an investment in new capacity.

Given this predicament for investors, the analysis then evaluates the financial implications of providing a sufficient supplement to the earnings of a potential investor to make an investment in peaking capacity occur. The three alternative procedures considered are (1) using a direct contract for the new capacity, (2) increasing payments in a capacity auction to cover the annual capital cost of peaking capacity, and (3) increasing the number and frequency of price spikes in the spot market. The results show that the first procedure is by far the least expensive because most of the additional costs using the other two procedures go to the owners of installed capacity. Furthermore, there is no obligation placed on the owners of installed capacity to invest in new capacity. In contrast, the direct contract is, by definition, an obligation to build a specified amount of peaking capacity. These conclusions are summarized in Section 4.

2 An Analytic Framework for Evaluating Forward Contracts for Electricity

2.1 The Financial Risk of Transactions in the Spot Market

Spot prices in a deregulated electricity market like PJM tend to be highly volatile in the summer months when the load is high. This was particularly true in 1999 when suppliers were first allowed to submit market-based offers into the auction. Mount and Oh (2004) describe how suppliers behaved in this auction, and they show how computer agents can be used to replicate the behavior of suppliers and the price volatility in this spot market. In a deregulated electricity market, uncertainty about the actual level of system load makes it rational for some suppliers to speculate with marginal generators, and the result is a supply curve shaped like a hockey stick. Figure 1 shows the actual offers submitted at 5pm on the last Tuesday of April to August in 1999. Speculative offers were submitted in all of the cases shown in Figure 1 even though the total capacity offered varied a lot. When load is high relative to the total capacity offered into the auction, a price spike may occur, and a price spike did occur in the case for July in Figure 1.

Figure 2 shows the daily average on-peak price and load in the PJM spot market from April,

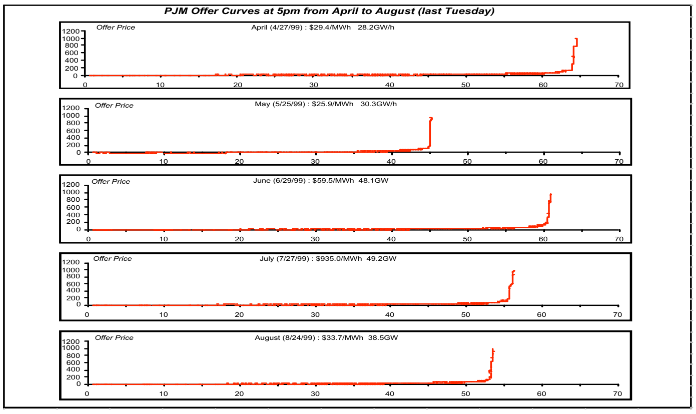

Figure 1: Supply Curves Offered into the PJM Auction in 1999

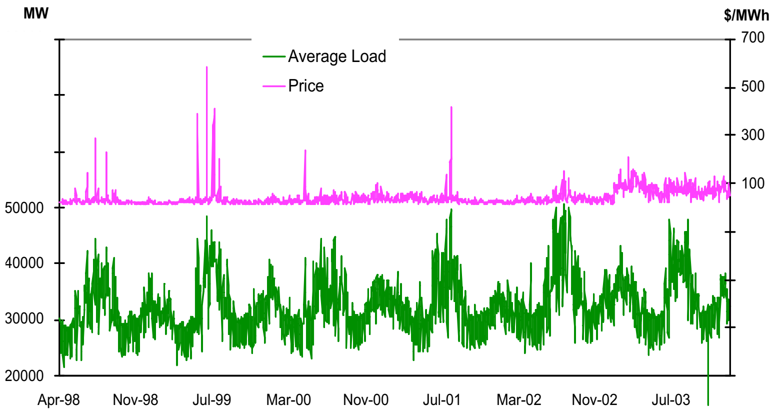

Figure 2: Average On-Peak Price and Load in the PJM Spot Market

1998 to December, 2003. The price spikes in the summer of 1999 are higher and more frequent than they are in other years. In 1998, offers into the auction had to be based on the true costs and speculation was not allowed. Following 1999, high prices have been mitigated by a number of factors, such as new capacity, load response and AMP. The overall implications for a deregulated market are (1) both price risk and volume risk are important features, and (2) the risk is much higher in the summer than it is in other seasons.

Since the high loads in the summer determine the amount of generation capacity needed for system adequacy, our analysis will focus on the summer months. The basic assumption is that some peaking capacity is only needed during the summer, and as a result, the total annual earnings for this capacity must accrue during the summer. In addition, we assume that day-to-day variability in earnings is inevitable. It is the variability of the cumulative earnings over the summer that matters for financial risk. This is consistent with the standard financial reporting of public companies every quarter. In other words, we assume that a firm is concerned about the profit or loss in each quarter. In addition, we assume that firms are risk averse and want to avoid losses. The next step is to show that a DISCO faces more risk than a GENCO in the spot market.

The basic assumptions for a DISCO are (1) it has an obligation to meet a fixed proportion (5%) of the zonal load, (2) it is in a transition phase of deregulation and is paid a fixed regulated rate by customers, and (3) it has other financial obligations to cover, such as the cost of maintaining the distribution system. If the DISCO purchases all electricity in the spot market to meet load, the price risk and volume risk are substantial. On a day when the load is high and a price spike occurs, the DISCO still has to purchase electricity even though the regulated price paid by customers is less than the spot price. During a hot summer, this situation will occur relatively often and the DISCO may make a cumulative loss by the end of the summer. The obligation to serve customers is the underlying reason why Pacific Gas and Electric declared bankruptcy during the crisis in California in 2000.

On the supply side of the market, it is assumed that there are two types of firms. One owns base load capacity and the other owns peaking capacity. Both types of GENCO have predetermined costs of production (i.e. the prices of fuels and other inputs are fixed in forward contracts). The main difference between a DISCO and a GENCO is that a GENCO does not have to produce if the spot price is below the marginal cost. This is equivalent to holding a call option with the strike price equal to the marginal cost. Unlike a DISCO, a GENCO is not vulnerable to operating losses but there is no guarantee that earnings will cover the full cost of capital. Since the DISCO and the GENCO face the same spot prices in the analysis, we are implicitly ignoring the possibility of price differences due to congestion on the network.

The underlying source of risk faced by both a DISCO and a GENCO is the stochastic nature of the weather during the summer. High temperatures are associated with high loads and high prices in the spot market. Weather generators can be used to determine realistic realizations of daily temperatures (Yoo, 2004), and we use a sample of 1000 realizations of temperature patterns in the summer to determine the stochastic properties of the load and spot price. The description of these simulations and the specifications for the DISCO and the GENCO are given in Section 3 (the cost structures of the GENCO and the DISCO in Figure 3 and 4 are simpler than they are in the simulations). The purpose here is simply to illustrate the differences in financial risk faced by a DISCO and a GENCO in the spot market.

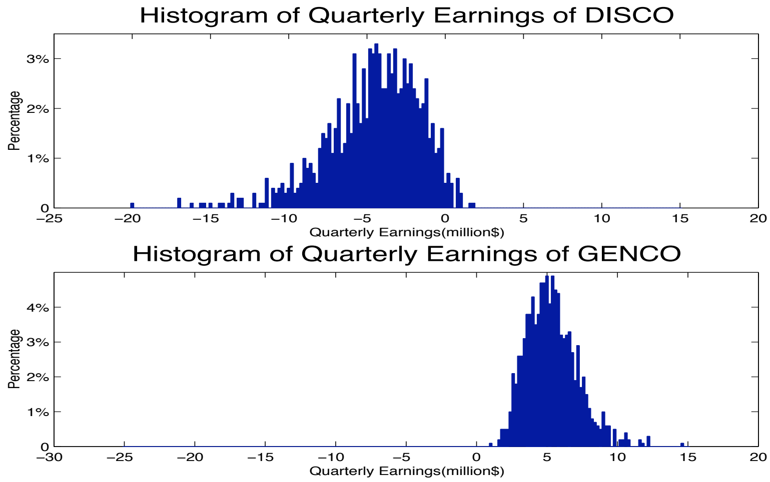

Figure 3: Quarterly earnings of a DISCO and a GENCO (million$)

The results summarized in Figure 3 show the relative frequencies of the quarterly earnings for a DISCO and a GENCO (peaking) using the sample of 1000 summers. The difference between them is obvious. The distribution for the DISCO is skewed to the left and the distribution for the GENCO is skewed to the right. The GENCO never makes a loss, but the DISCO makes a loss most of the time and the magnitudes of some losses are substantial. On average, the DISCO makes a loss (-$4.5million), which must be recovered in other seasons, and the GENCO makes a profit ($5.3million). The results in Section 3 show that the DISCO is willing to accept a larger average loss to avoid the very large losses that can occur in a hot summer. This implies that the GENCO is paid a risk premium in a forward contract.

The financial risk faced by a DISCO in the spot market can be offset by purchasing forward contracts at predetermined prices. The structure of these contracts is affected by the shape of the load duration curve, and Figure 4 shows this curve for a typical summer. The shape implies that roughly 250MW of base load capacity is needed and up to 600MW of total capacity. These values, particularly the latter, are highly sensitive to the specific temperature pattern in the summer. The basic strategy of the DISCO is to hold a fixed price/fixed quantity contract, called a fixed delivery contract, to cover a proportion of the base load. This type of contract is similar to the financial contract-for-differences traded on the NYMEx, but a fixed delivery contract is not appropriate for

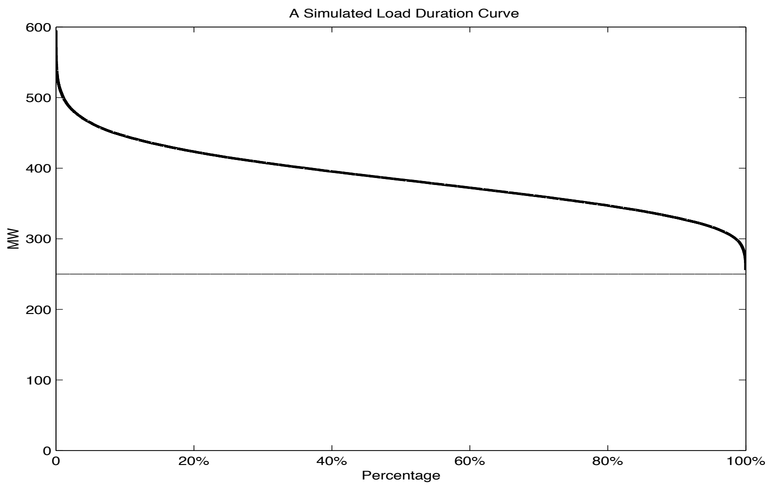

Figure 4: A Simulated Load Duration Curve

the peaking load because this load varies hour by hour. A two-part contract is used for the peaking load that specifies a price per MW for capacity and a price per MWh for the actual amount of electricity purchased. This type of contract is not traded on the NYMEx, and it would be executed as a bilateral contract in the Over-the-Counter market.

In an active and efficient market, the prices in the two different contracts will be closely related together, because there should be no arbitrage opportunities between them and both contracts will reflect expected conditions in the spot market. The analytical framework developed in the next sub-section presents a procedure for evaluating financial risk and pricing forward contracts given the stochastic characteristics of the spot market. The basic rule is that both a DISCO and a GENCO must benefit from holding a forward contract (based on expectations about future outcomes when the contract is signed). Using this framework, the optimum portfolio of forward contracts can be determined. This portfolio implies that there is equilibrium in the spot and forward markets.

2.2 Risk Measurement and Optimal Trading

The economic literature discusses numerous ways of measuring financial risk, such as the variance, expected value of loss, semi-variance, value at risk, conditional value at risk. Modern forms of measuring risk have evolved from the original paper by Markowitz (1952) on the portfolio problem. This theory specifies the mean and variance of stock returns as the arguments of an expected utility function. It can be shown that if the utility function is quadratic, expected utility will increase in mean and decrease in variance for all forms of probability distribution in the portfolio. For this utility function, only the first two moments matter. Also, if the utility function has an exponential form and the portfolio follows a normal distribution, the first two moments uniquely determine the expected utility. However, a quadratic utility function has an unrealistic property because the utility decreases when the total return is above a certain point. Using an exponential form of utility function restricts the absolute level of risk aversion to be a constant (equal to its power). For some portfolios, the symmetry of a normal density function is hard to justify. Furthermore, since the variance is a symmetric measure of risk, the positive deviations of total returns above the mean are penalized just as much as the negative deviations. This is not a desirable property if traders are averse to losses.

Given the limitations of using the variance to measure risk, a number of "downside" risk measures have been proposed. For example, Value at Risk (VaR) and Conditional Value at Risk (CVaR) are widely used today. Let $l(x;Y)$ denote the loss function for a decision variable x that is chosen from a specified subset X, where Y is a random vector. For our application, the value of x represents the return from a specific portfolio chosen from the set X of all available portfolios, and Y represents uncertainties in the market. If the probability density function of Y is $p(y)$, where y is a realization of Y, the probability of not exceeding a threshold level of loss will be:

$$\Psi(x, \alpha) = \int_{l(x,y)<\alpha} p(y)dy$$

The definition of VaR with confidence level β of the loss associated with a decision variable x (i.e. β -VaR) is the minimum loss:

$$\alpha_\beta = min\{\alpha|\Psi(x, \alpha) \geq \beta\}$$

The corresponding definition of CVaR with confidence level β of the loss associated with a decision x (i.e. β-$CVaR$) is:

$$\phi_\beta = \frac{1}{1-\beta} \int_{l(x,y)>\alpha_\beta} l(x, y)p(y)dy$$

VaR is convenient to use because it is analytically tractable, but it has received much criticism for its inability to differentiate between a portfolios with large losses less than α and another with small losses less than α that both have the same probability β of occurring. The reason for this is that only the probability of a loss less than α matters for VaR and not the magnitude of the losses less than α. While β-VaR measures the loss that is exceeded in $(1-\beta)100\%$ of the possible outcomes, β-$CVaR$ is the expected level of loss, conditioned on the loss being greater than or equal to VaR. Even though CVaR accounts for the magnitude of losses beyond VaR, it ignores the risk of losses above VaR, and it assumes implicitly that the risk of any volatility above α is zero.

In an electricity market, the results presented in Section 2.1 (Figure 3) show that the probability of large losses for a DISCO is a central feature of the market, and a risk measure that penalizes large losses is needed. In addition, the risk of volatile returns above some threshold value may also be important for a GENCO. Motivated by this, we propose a utility function that accounts for risk at all levels of return but penalizes downside risk more heavily. The following function is a scaled form of the Linex function that has been discussed extensively by Bell (1994):

$$u(\omega) = (1 - ab)\omega + b(1 - exp(-a\omega)) \tag{1}$$

where ω is the level of wealth, and a and b are parameters.[1] Under the regularity conditions ($a > 0, b > 0$ and $ab < 1$), it can be shown that this is the only form of utility function with the following set of desirable properties:

Property 1: the firm prefers more wealth to less, i.e., $u'(\omega) > 0$.

Property 2: the firm is less risk averse as wealth increases, i.e., $r = -u''(\omega)/u'(\omega) > 0$ and r is monotonically decreasing.

Property 3: the firm becomes risk neutral when earnings are high.

Property 4: utility is negative for negative earnings and positive for positive earnings.

Property 5: the marginal utility evaluated at 0 is 1, i.e., $u'(0) = 1$.

The Linex function is an asymmetric measure of risk, and it reflects a firm's downside risk aversion by penalizing big losses ($w \leq 0$) very severely (i.e., $-\infty < -b \exp(-a\omega) < -b$) and penalizing positive profits ($w \geq 0$) much less(i.e., $-b < -b \exp(-a\omega) < 0$). As profits increase, the penalty goes to zero and the firm becomes risk neutral. The utility function used in the analysis

[1] Jarrow and Zhao (2003) claim that an agent's downside loss averse utility can be specified over the portfolio's return:

$$u(w) = \begin{cases} f(w), & \text{for } w >= a; \\ f(w) + g(w), & \text{for } w < a. \end{cases}$$

where f and g are increasing and f is concave. The function g embodies the investor's aversion toward downside losses ($x < a$), while the function f represents a standard risk averse utility function. The reference level a can be a constant or depend on the distribution of returns. They show that the Linex function is a special case of this general model.

with $a = 1000$ and $b = 0.0005$ is shown in Figure 5.[2] Given the distributions of earnings in Figure 3, the behavior of a DISCO will be much more risk averse than the behavior of a GENCO.

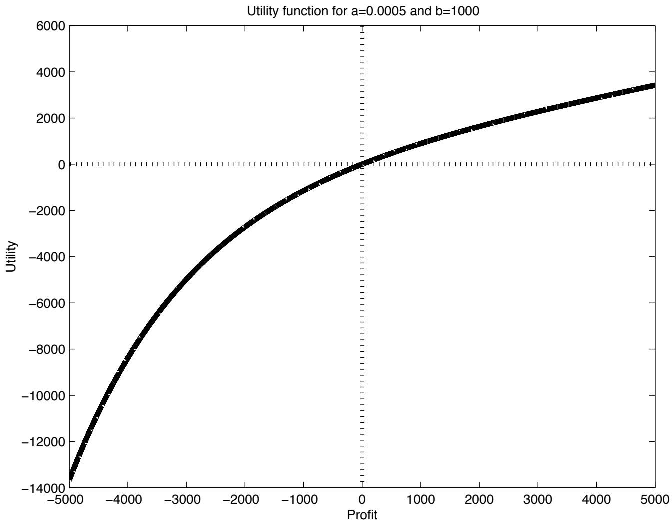

Figure 5: Plot of utility function

Using the form of a utility function in (1), the next step is to define the conditions under which a DISCO and a GENCO will be willing to trade a forward contract. The basic principle is that the expected utilities for both the DISCO and the GENCO from holding a forward contract must be greater than the corresponding expected utilities of making all transactions in the spot market. In practice, the different levels of market power among the DISCOs and the GENCOs in an electricity market will determine the relative benefits of a trade. To capture various degrees of market power, we use a standard Nash bargaining game to model the negotiation process between the DISCO and the GENCO. In this model, the arbitrator of the negotiations about a forward contract maximizes the power weighted product of the two utility gains from the forward contract, where the weights represent their relative market power. This can be represented as follows:

$$\max_{\Omega}[U(\Pi_{d1}) - U(\Pi_{d0})]^{\theta}[U(\Pi_{g1}) - U(\Pi_{g0})]^{1-\theta},$$

subject to the participation constraints (the individual rationality conditions that both firms must benefit),

$$U(\Pi_{d1}) > U(\Pi_{d0})$$

[2]The values for a and b are derived from the prices of swap contracts traded in NYMEx. We will present the details in another research paper.

$$U(\Pi_{g1}) > U(\Pi_{g0})$$

where U is the expected utility function, and $\theta \in [0, 1]$ represents the DISCO's relative market power, and $U(\Pi_{d1})$, $U(\Pi_{g1})$ are the DISCO's and the GENCO's expected utility with contract Ω, and $U(\Pi_{d0})$, $U(\Pi_{g0})$ are the DISCO's and the GENCO's expected utility in the spot market. In our analysis, we assume that the GENCO and the DISCO have equal market power, so $\theta = 0.5$.

2.3 Specifications of the Contract Portfolio

Based on the discussion in Section 2.1, the representative DISCO holds a contract portfolio that consists of a fixed price/fixed quantity contract for base load and a two-part contract for peaking load. Denote the fixed contract as (Q_b, P_b), where Q_b is the contract quantity(MW), and P_b is the contract price($/MWh). Denote the two-part contract as (Q_p, L_p, P_p). Q_p is the maximum quantity that the DISCO can purchase from the GENCO for each delivery hour(MW). Initially, Q_p is set to be equal to the DISCO's maximum peak load D_{max}, i.e., $Q_p = D_{max}$. L_p is the fixed charge for Q_p. P_p is a vector of variable prices when a purchase occurs ($/MWh). Let V_i denote the variable price for i^{th} peak unit, then $P_p = \{V_1, V_2, ..., V_{D_{max}}\}$. To be consistent with the stacked supply curve, the elements of P_p has to satisfy the following condition, $V_1 \leq V_2 \leq, ..., \leq V_{D_{max}} \leq P_{cap}$, where P_{cap} is the price cap in the market. If $V_i = P_{cap}$, it is equivalent to not holding a contract because the market provides an automatic call option with the strike price equal to P_{cap}. Q_p corresponds to the highest load with $V_i < P_{cap}$.

Further assume that the quantity and price for the fixed contract is known when the two-part contract is signed, and the quantity in the contract exactly covers the base load. So the following discussion will focus on the trading between the DISCO and the peaking GENCO (denoted as the GENCO in the following discussion). An additional restriction is that the capacity purchased from the two-part contract can only be used to meet the DISCO's own load, and cannot be sold to other DISCOs. The reason for this restriction is that it ensures that there is equilibrium between demand and supply in the market.

Let q_b, q_p and q_s denote the real-time purchase from the fixed contract, the two-part contract and the spot market, respectively. It follows from the assumptions that the DISCO's peaking load is $D = q_p + q_s$, $q_p \leq Q_p$ and $q_b = Q_b$.

For the representative GENCO, the true marginal cost for i^{th} unit is $MC = m + n * i$. The

GENCO receives the fixed charge L_p from the DISCO, and is also paid for q_p units at the variable price $\{V_1, V_2, ..., V_{q_p}\}$ in real time whenever a purchase occurs. However, the GENCO has to pay a standby cost $\$s/MW$ for being available to the DISCO in the two-part contract. The GENCO can sell any excess capacity to the spot market, but this quantity cannot exceed q_s to be consistent with a market equilibrium.

The notation of the contract are summarized below:

Contract Notation:

- Q_b — Contract quantity for the fixed price/fixed quantity contract.
- P_b — Contract price for the fixed price/fixed quantity contract.
- Q_p — Contract quantity in the two-part contract.
- P_p — Variable price in the two-part contract. $P_p = \{V_1, V_2, ..., V_{Q_p}\}$, where V_i is the variable price for i^{th} peak unit.
- L_p — Fixed Charge in the two-part contract.

General Notation:

- C — DISCO's Fixed Cost paid for maintaining the distribution system.
- s — GENCO's Standby Cost for being available in the two-part contract.
- R — Regulated Price for the DISCO.
- $MC(i)$ — GENCO's marginal cost for i^{th} unit, defined as $MC(i) = m + n * i$.
- D — Peaking load. It is a random variable with probability density function $f_D(i)$. D will take values $(1, 2, ..., i, ...D_{max})$, where D_{max} is the maximum peaking load.
- P — Spot price. It is a random variable with the conditional probability distribution function $\Phi_{P|D}(p|i)$. $MC < P < P_{cap}$, where P_{cap} is the price cap.

Preassigned Relations:

- $Q_b = q_b$

- $Q_p \leq D_{max}$

- $D = q_p + q_s$

- $\theta = 0.5$

In this contract portfolio, the unknown variables are $V_1, V_2..., V_{Q_p}$ and L_p, and the following equilibrium framework is used to solve these unknowns.

Objective Function:

$$\max_{V_1,...,V_{Q_p},L_p} [U_{d1} - U_{d0})]^{\theta}[U_{g1} - U_{g0}]^{1-\theta}, \tag{2}$$

subject to,

$$U_{d1} > U_{d0}$$

$$U_{g1} > U_{g0}$$

$$V_1 \leq V_2 \leq ... \leq V_{Q_p} \leq P_{cap}$$

where,

$$U_{\bigstar} = \sum_{i=1}^{D_{max}} \left\{ f_D(i) \int_{C(i)}^{P_{cap}} u(\pi_{\bigstar}|i,p)\Phi_{P|D}(p|i)dp \right\} \tag{3}$$

Notion "$\bigstar$" stands for $d1, d0, g1$ or $g0$. The integral in (3) stands for the expected utility given a peaking load i. The summation determines the expected utility for all the load levels.

The following expressions describe the profit function for the DISCO and the GENCO.

- U_{d0} — DISCO's expected utility with only a fixed delivery contract, defined in (3), with conditional profit:

$$\pi_{d0} = (Q_b + i) * R - P_b * Q_b - ip - C \tag{4}$$

  In (4), $(Q_b + i) * R$ is the DISCO's revenue, $P_b * Q_b$ is the cost of the fixed price/fixed quantity contract, ip is the cost of purchasing peaking load in the spot market, and C is the cost of maintaining the distribution system.

- U_{d1} — DISCO's expected utility with two contracts, defined in (3), with conditional profit:

$$\pi_{d1} = (Q_b + i) * R - P_b * Q_b - \sum_{k=1}^{i} Min(p, V_k) - Q_p * L_p - C \tag{5}$$

(5) has the same structure as (4), except that the DISCO has to pay $(Q_p * L_p)$ for the peaking contract. In return, the DISCO can choose to purchase peaking load either from the spot market or from the two-part contract, so the variable cost of peaking load is $\sum_{k=1}^{i} Min(p, V_k)$.

- U_{g0} — GENCO's expected utility without any contracts, defined in (3), with conditional profit:

$$\pi_{g0} = \sum_{k=1}^{i} (p - MC(k))^+ \tag{6}$$

Without any contracts, the GENCO sells power up to i in the spot market, and earns $(p - MC(k))^+$ per unit, where $1 \leq k \leq i$. In the simulation, the spot price for peaking load k is never less than the marginal cost $MC(k)$.

- U_{g1} — GENCO's expected utility with two-part contracts, defined in (3), with conditional profit:

$$\pi_{g1} = \sum_{k=1}^{i} (p - MC(k))^+ + Q_p * L_p - \sum_{k=1}^{i} (p - V_k)^+ - s * Q_p \tag{7}$$

With a two-part contract, in addition to the original profit, the GENCO will earn $Q_p * L_p$ from the two-part contract. In return, the GENCO pays back $\sum_{k=1}^{i}(p - V_k)^+$ to the DISCO. Also, the GENCO has to pay a standby cost $s * Q_p$.

The above discussion is based on the hourly profit. In our context, both the GENCO and the DISCO are more concerned about the profit for the whole summer season. The extension from the hourly-based profit function to summer-based profit is straightforward. Since close forms for the probability distributions of loads and prices are not available, we use simulation to solve the optimization problem stated in (2).

(2) is a highly constrained optimization problem. In order to obtain a global maxima, Simulated Annealing, a heuristic optimization method, is used to solve this problem (Kirkpatrick et al., 1983). Simulated annealing is a technique used to find a global optimum by trying random variations of the current solution. A lower value of the objective is accepted as the new solution with a specified probability that decreases as the computation proceeds. The origin of the first simulated annealing is generally recognized as a Monte Carlo importance-sampling technique for doing large-dimensional path integrals arising in statistical physics. The procedures can be described as follows: from the current state, pick a random successor state. If it has a higher value than the current state, then

accept the transition and use the successor state as the current state. Otherwise, do not give up, but accept the transition with a given probability. The acceptance probability is big at initial stages, and goes to zero eventually. In this way, the algorithm can escape local maxima, and move towards the global maximum.

3 Investment Decisions and Policy Analysis

3.1 The Risk of An Investment

The primary objective of this sub-section is to determine the profit requirement for investing in new peaking capacity (a gas turbine generator) by first deriving the mortgage formula, and then deriving the required profit for an investment in a risky project.

Assume that the profit per year from an investment is M, the project life is T years, the interest rate is r, the total investment is I, and the profit is realized at the end of each year. Under the no arbitrage assumption, the present value of profits must equal the cost of the investment I. With a one year delay for construction, the following relationship between I and M holds:

$$\begin{aligned} I &= M(1+r)^{-2} + M(1+r)^{-3} + ... + M(1+r)^{-T-1} \\ &= \frac{M[(1+r)^T - 1]}{r(1+r)^{T+1}} \end{aligned} \quad (8)$$

and

$$M = \frac{Ir(1+r)^{T+1}}{(1+r)^T - 1} \quad (9)$$

For the simulation presented in Section 3.3, the specified value of M is $\$85/KW$ per year. If the project life is 20 years and the interest rate is 10% per year, the corresponding cost, I, using (8) is:

$$I = \frac{85[(1+10\%)^{20} - 1]}{10\%(1+10\%)^{21}} = \$658/KW$$

A second issue concerns how an investment is financed. If 50% of the cost is covered by a 5-year loan ($debt/equity = 1$) and this debt is paid back through five annual installments after a delay of two years, the installment M using (9) is (the interest rate is 10%):

$$M = \frac{\frac{658}{2} \times 10\% \times (1+10\%)^6}{(1+10\%)^5 - 1} = \$95/KW$$

In (8) and (9), there is no uncertainty about the value of M. Under risk neutrality, M is equivalent to the expected annual profit, but higher annual profits will be needed if an investor is risk averse. When an investment is viable, the weighted sum of the expected annual utilities from the investment must be larger than the corresponding weighted sum from putting the same money in a bond at the risk-free rate of return. For a typical year, the condition is $u(M) \leq E[u(\Pi)]$, where u is the utility function and Π is the stochastic annual profit. In the example above, the equity for a 1000MW generator is \$658/2 million, and this amount is equivalent to a certain annual income of $M = \$38$ million/year until the end of the project in 21 years[3]. Assuming that utility is discounted at the risk-free rate, the present value of utility is:

$$u(38)((1+r)^{-1} + (1+r)^{-2} + \ldots + (1+r)^{-20} + (1+r)^{-21}) = u(38) \times 8.65 \tag{10}$$

The corresponding present value for a risky investment in peaking capacity is:

$$\begin{aligned} & E[u(\Pi - 95)(1+r)^{-2} + \ldots + u(\Pi - 95)(1+r)^{-6} + \\ & \qquad u(\Pi)(1+r)^{-7} + \ldots + u(\Pi)(1+r)^{-21}] \\ & = E[u(\Pi - 95)] \times 3.45 + E[u(\Pi)] \times 4.29 \end{aligned} \tag{11}$$

Since (11) has to be greater than or equal to (10), the value Π^* that makes (11)=(10) is the minimum expected profit requirement for investing in new peaking capacity. Using the utility function described in Section 2.2, the minimum expected profits is $\Pi^* = \$90$/KW/year. The extra \$5/KW/year needed to make the investment viable corresponds to the costs of delay for construction and to paying off the bond in five years. The net profit for the first five years of the project is -\$5 million/year, and then increases to \$90 million/Year for the remaining 15 years of the project.

[3]Using (9) again, $M = \frac{\frac{658}{2} \times 10\% \times (1+10\%)^{21}}{(1+10\%)^{21} - 1} = 38$.

3.2 Specifications of the Simulation Model

The relationship between temperature and the demand (load) for electricity is well understood (Ramanathan et al., 1997; Bunn, 1999 and 2000). Using relatively simple forms of ARMA models (Box and Jenkins, 1976), it is possible to predict the daily maximum load with a 1-2% forecasting error using temperature as an input variable (Ning, 2001). The daily temperature can also be represented by a Guassian ARMA model with an annual cycle (Yoo, 2004). The relation between load and price is more complicated, and an innovation of previous research was to predict the daily price of electricity (average for the sixteen-hour peak) using a stochastic regime switching model (Hamilton, 1994; Ethier and Mount, 1999; Mount, Cai and Ning, 2004). One regime has a low average price with a small variance and the other has a high average price with a large variance. This paper uses a simpler form of regime switching model for the price that is easier to modify for policy analysis.

The simulation model uses data for New York City because this is a region that may face a shortage of generating capacity in the relatively near future. The estimation results for all of the regression models are given in appendices.

The average on-peak temperature (from 7:00am-23:00pm) for New York City is modelled as,

$$T_t = \mu_t + \varepsilon_t \tag{12}$$

where μ_t is the mean of the temperature T_t and ε_t is a residual. The mean and variance follow annual cycles:

$$\mu_t = \alpha_0 + \alpha_1 sin(\omega t) + \alpha_2 cos(\omega t) \tag{13}$$

$$log(\sigma_t^2) = \beta_0 + \beta_1 sin(\omega t) + \beta_2 cos(\omega t) + \epsilon_t \tag{14}$$

$$\varepsilon_t/\sigma_t = \frac{1 - \theta_1 L}{1 - \phi_1 L - \phi_2 L^2 - \phi_3 L^3}\nu_t \tag{15}$$

where $\varepsilon_t \sim N(0, \sigma_\varepsilon^2)$, $\epsilon_t \sim N(0, \sigma_\epsilon^2)$, $\nu_t \sim N(0, \sigma_\nu^2)$, $\omega = 2\pi/365$, and L is a lag operator defined as $L^i Y_t = Y_{t-i}$.

The model is estimated in three stages. First, T_t is regressed on an annual cycle to estimate (12). Second, the computed residuals, $\hat{\varepsilon}_t$, are used to estimate (14) with $\hat{\varepsilon}_t^2$ replacing σ_t^2, and third, the weighted computed residuals, $\hat{\varepsilon}_t/\hat{\sigma}_t$, are used to estimate (15). The estimation results are presented in Table A1.

The average peak-load in New York City (zone J) is modelled by the following ARIMA model:

$$\begin{aligned} D_t = \mu + \alpha_0 m_t + \alpha_1 tu_t + \alpha_2 w_t + \alpha_3 th_t + \alpha_4 holiday_t + \alpha_5 trend_t + \alpha_6 cdd_t \\ +\alpha_7 hdd_t + \alpha_8 sin_{1t} + \alpha_9 cos_{1t} + \alpha_{10} sin_{2t} + \alpha_{11} cos_{2t} + \alpha_{12} sin_{3t} + \\ \alpha_{13} cos_{3t} + \frac{1-\theta_1 L}{(1-\phi_1 L - \phi_2 L^2 - \phi_3 L^3)(1-\phi_4 L^7)} \varepsilon_t \end{aligned} \quad (16)$$

where $\varepsilon_t \sim N(0, \sigma_\varepsilon^2)$. The definition of the variables are summarized in the Table A2 and the estimation results are presented at Table A3.

A bilinear model is used to describe the relation between the average on-peak prices and the average on-peak loads for the summer. Data for the summers 2001 and 2002 are used for the estimation (Data for 2003 are excluded from our sample due to the well-known blackout in August). When the load is below $8000MW$, spot prices are relatively stable. When the load is above $8000MW$, price spikes occur frequently. Therefore, the prices are divided into a low-price regime($<$ \$85/MWh) and a high-price regime. All the prices for loads below $8000MW$ belong to the low-price regime. When loads are above $8000MW$, prices can belong to either the low-price regime or the high-price regime. The probability of being in the high-price regime could be estimated directly by the observed proportion of high prices in the sample, but this probability is specified in the simulation. The following two regressions represent the relation between load and price:

$$log(P_{ht}) = \alpha_0 + \alpha_1 log(load_t) + \varepsilon_t \quad (17)$$

$$log(P_{lt}) = \beta_0 + \beta_1 log(load_t) + \beta_2 (log(load_t))^2 + \epsilon_t \quad (18)$$

Where P_{ht} and P_{lt} are the average on-peak prices in the high-price regime and the low-price regime, respectively, $\varepsilon_t \sim N(0, \sigma_\varepsilon^2)$ and $\epsilon_t \sim N(0, \sigma_\epsilon^2)$. The estimation results are presented in Table A4. The estimates of (18) shows that the relation between price and load in the low-price regime is approximately linear.

The models (12)-(18) make it possible to predict the daily temperatures, loads and spot prices for New York City during a summer. The basic source of risk in the market is whether the summer is hotter or cooler than normal. One thousand realizations of summer temperatures were computed

Table 1: Parameter Specifications for the Simulation

Date Coverage by simulation	Summer Peak Hours: 16 hours/day×22 days/month×3 months/summer
Load	• Modelled by a ARIMA process, with temperatures as one input variable • Restricted to be always greater than 5000MW
Spot Prices (P)	$\begin{cases} log(P_t) = 121.88 - 28.31log(load_t) + 1.69(log(load_t))^2 + \epsilon_t, & \text{if } D < 8000 \text{ MW;} \\ log(P_t) = \lambda[121.88 - 28.31log(load_t) + 1.69(log(load_t))^2 + \epsilon_t] & \\ +(1-\lambda)[-42.29 + 5.21log(load_t) + \varepsilon_t], & \text{if } D >= 8000 \text{ MW;} \end{cases}$ where $\epsilon_t \sim N(0, 0.04^2)$, $\varepsilon_t \sim N(0, 0.08^2)$ and $\lambda = \begin{cases} 1, & \text{with probablity 0.5;} \\ 0, & \text{with probablity 0.5.} \end{cases}$ prices are restricted to be always above marginal cost
DISCO	• Always face 5% of the system load • Paid at a regulated rate \$120/MWh, pay \$60/MW/Hour multiplied by average load for all other costs
GENCO	• Marginal cost is constant when stacked capacity is less than 5000MW. Linear otherwise • Equal to \$5/MWh when stacked capacity equal to 5000MW • Equal to \$90/MWh when stacked capacity equal to 10000MW • Standby cost \$2/MW/day
Utility Function	$u(w) = (1 - ab)w + b(1 - exp(-aw))$, where a=0.0005 and b=1000.

using Gaussian residuals, and these temperatures were then used to predict the load and the spot price. When the predicted load is greater than 8000MW, the probability of being in the high-price regimes is specified to be 50%. This is roughly twice as high as the observed proportion of high prices. A larger value was used to illustrate more effectively how price spikes make the market more risky for buyers than for sellers.

The final part of the simulation specifies the earnings of a DISCO and a peaking GENCO. The load of the DISCO is equal to 5% of the total system load. Customers pay a regulated rate of \$120/MWh, and the DISCO has to cover a fixed cost of \$60/MW times the average load (385MW), representing distribution costs.

The costs faced by the GENCO have a simple structure to accommodate the analysis of forward contracts. The marginal cost of production is specified as a fixed linear function of the load. This is equivalent to holding forward contracts for all inputs and having a quadratic cost function. The marginal cost at the average load (7700MW) is \$51/MWh, and the marginal cost increases by \$17/MWh for every 1000MW of additional load. The values of the marginal cost were specified to be below the predicted prices (to be consistent with economic logic), and the constraint that price is greater than marginal cost is imposed for all loads. In addition, predicted loads are constrained to be greater than 5000MW, but relatively few observations violated these constraints. All of the simulation specifications are summarized in Table 1.

3.3 Simulation Results

The simulation model described in Section 3.2 provides a framework for evaluating the financial risk faced by a DISCO and a GENCO. Since the focus of this sub-section is on peaking capacity, it is assumed that the DISCO holds a fixed price/fixed quantity contract with a base load GENCO to cover the minimum load of 250MW at a price of \$68/MWh, equal to the average daily spot price (unweighted, on-peak). The objective of this sub-section is to determine the optimum contract for the peaking load above 250MW between the DISCO and a peaking GENCO using the trading framework specified in (2). The DISCO is assumed to be one of 20 identical buyers in the market, and for simplicity, the GENCO is one of 20 identical sellers. In addition, there are an unspecified number of base load GENCOs supplying $250 \times 20 = 5000MW$ of base load through forward contracts. A final simplification is to assume that all of the earnings in the summer for both the DISCO and the peaking GENCO accrue during the on-peak hours, corresponding to a 16-hour contract for 66 weekdays.

If the DISCO makes all purchases in the spot market, the average price is \$71/MWh (weighted by load). The average price (unweighted) for base load is \$68MWh, and the average price for peaking load is \$77/MWh (see Table 3). Paying these prices implies that the DISCO makes a loss of \$11/MWh on average for the summer months. The revenue is determined by the fixed regulated rate (\$120/MWh), and the average costs are \$60/MWh for distribution and \$71/MWh for electricity. Since customers always pay the same regulated rate, this loss in the summer would be covered in other seasons when the average price of purchasing electricity is lower.

Figure 6 plots the optimal variable prices for the two-part contract. The lower line is the GENCO's marginal cost curve, and the line above is the optimal variable price in the two-part contract determined by the trading optimization. Since the price cap is \$1000/MWh, the DISCO and the GENCO do not benefit by contracting the last 50 MW. So the overall contract quantity in the two-part contract is $250MW$. The optimal contracts are shown in Table 2. The total contract quantity is $250+250 = 500$MW, which is much higher than the average load ($385\times 20 = 7700$MW) of the DISCO and corresponds to the 99^{th} percentile of the load. However, the total contract quantity is still lower than the maximum load (550MW). The lump sum payment in the two-part contract is \$18/KW/year, which is equivalent to \$17/MW/hour in the summer. The contract quantity is sensitive to the standby cost, and a higher standby cost will reduce the optimal contract quantity.

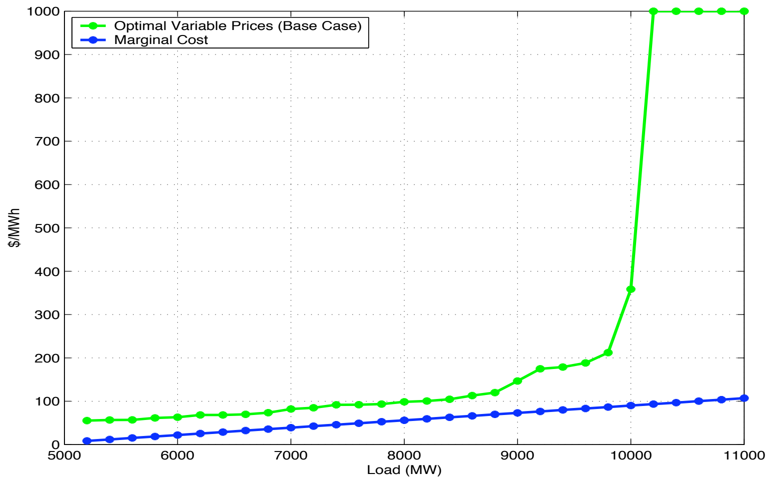

Figure 6: Optimal Variable Prices for Two-Part Contracts: Normal Case

Table 2: Summary of the Optimal Forward Contracts

	Fixed Delivery Contract	Peaking Two-part Contract
Contract Quantity(MW)	250	250
Lump-sum ($/KW/year)	0	18

Table 3: The Costs of Purchases by a DISCO

	Spot Market	Two Market contracts
Average Revenue (Regulated Rate-Other Costs)	60 (120-60)	60 (120-60)
Average Price Paid for All Load ($/MWh)	71	76
For Baseload	68	68
For Peaking	77	89
Average Profit ($/MWh)	-11	-16

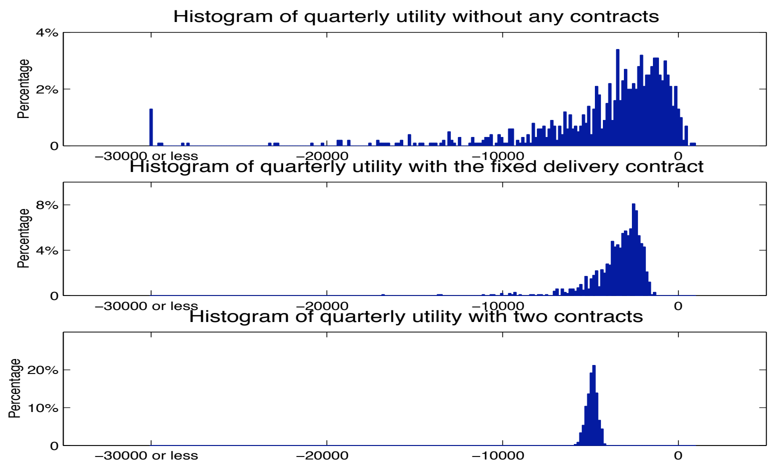

Figure 7: DISCO's Utility Levels With and Without the Two Contracts

With a two-part contract, the average price paid for peaking load by the DISCO is \$89/MWh (see Table 3), which is 16% higher than the corresponding average price in the spot market (\$77/MWh). This difference represents the premium paid by the DISCO to lower risk. Figure 7 plots the distributions of the utility of the earnings for the DISCO during the summer with and without contracts. The upper plot corresponds to no contracts, the middle plot to holding one fixed price/fixed quantity contract and the bottom plot to holding two contracts (one fixed price/fixed quantity contract and one two-part contract). It is obvious that the DISCO's quarterly utility level is skewed to the left with no contracts. With a fixed price/fixed quantity contract, utility is still skewed but the chance of big losses is much less. With two contracts, utility is almost symmetric and the variability is relatively small, but the mean value is lower.

3.4 Investment Incentives

When a peaking GENCO holds a two-part contract, the annual profit is only \$23/KW/year (see Table 4), which is less than 30% of the level needed to justify an investment in new generating capacity (\$90/KW/year, derived in Section 3.1). In order to provide a sufficient incentive for an investor to build new peaking capacity, additional incentives are needed. For the investment analysis, the new peaking capacity has a production cost (or marginal cost) of \$60/MWh. This production cost is chosen to be consistent with the specifications used in the current regulatory debate about investment incentives in New York (Reeder, 2002). The capital cost of \$85/KW/year, used in Section 3.1, is also consistent with these specifications and with the minimum profit of

$90/KW/year used in our analysis.

The next step in the analysis is to evaluate three alternative procedures for providing the incentives needed to make an investment in peaking capacity viable. The first is to require the DISCO to sign a direct contract with an investor to build a new generator. This implies that a premium of $67/KW/year (90-23) above the two-part contract must be paid to the investors. The other two procedures involve changing the market prices to give the "right" signals to potential investors. One procedure, that has been adopted in New York, is to increase payments in the Installed Capacity (ICAP) auction to cover the annual capital cost of peaking capacity whenever the projected installed capacity falls below the reliability standard. Using this procedure, all installed capacity is paid the premium of $67/KW/year in the ICAP auction and the spot market is not affected. The other procedure, that is equivalent to conditions in the Australian market, is to allow higher prices in the spot market. In Australia, the price cap is set to the Value of Lost Load (VoLL) and is equal to $10000/MWh. In our analysis, high price spikes (HSP) occur one day every ten summers on average. These additional price spikes are assumed to follow a normal distribution with mean $5000/MWh and standard deviation $1500/MWh, capped at $10000/MWh$. At the same time, the mean price in the low-price regime is lowered to make the arithmetic average price in the HSP case the same as it is the base case (the load weighted average prices will be higher than the base case). This makes the spot market more risky for the DISCO, but it also provides higher investment incentives for a GENCO. [4]

Table 4 lists the investors' annual profit, the DISCO's average price and the terms of the optimal contract under the two different specifications of the price spikes. Even though the arithmetic average price is the same with HSP, the average prices paid by the DISCO increase substantially in both the spot market and with two market contracts (because load and price are positively correlated). An important implication of HSP is that the annual profit for the GENCO must be

[4]The price cap in Australia was increased from $5,000 to $10,000/MWh in April 2002. In 2000, the ACCC (Australian Competition and Consumer Commission) released a final determination on electricity price caps in an amendment to the National Electricity Code for the National Electricity Market. Prices in the wholesale spot market normally vary between $30/MWh and $60/MWh, but can rise to $5,000/MWh, the current price cap. Prices near $5,000/MWh occur infrequently and are often due to peak demand on hot summer days or unanticipated plant failures in generators or transmission networks. The National Electricity Code Administrator proposed to increase the level of the price cap in two stages to $20,000/MWh. It argued that the higher price cap would encourage more investment in peaking generators and less demand for electricity at times of capacity shortage, thus leading to greater reliability. In spite of the higher price cap, average spot prices have fallen. This is the underlying rational for our HSP assumptions.

Table 4: Prices and Profits with High Spot Prices

	Base Case	High Spot Prices
mean price spike($/MWh)	**90**	5000
	Investor's annual profit ($/KW/year)	
spot market	**14**	21
two market contracts	**23**	**93**
	Average price paid by DISCO ($/MWh)	
spot market	**71**	85
two market contracts	**76**	123
	Optimal two-part peaking contract	
quantity(MW)	**250**	300
lump-sum($/KW/Year)	**18**	81

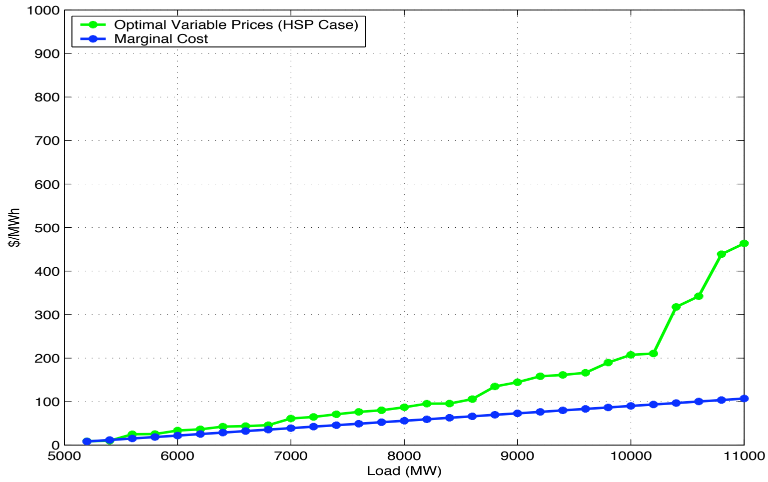

Figure 8: Optimal Variable Prices for Two-Part Contracts: High Spot Prices Case

above the minimum level of $90/KW/year required by investors for new capacity to compensate for higher risk . The optimal variable prices in a two-part contract with HSP are plotted in Figure 8. Under HSP, the variable prices are lower than that in the base case, but the contract covers the maximum load.

Table 5 lists the GENCO's annual profit for different market specifications. With a direct contract, the DISCO is required to provide an additional lump-sum to the investor. This additional payment is (90-23)=$67/KW/year. Relying on the spot market for peaking load, HSP gives an annual profit of $21/KW/year, but this is still not high enough to meet the investor's required annual profit. However, with two market contracts, HSP meets the profit requirement of the investor ($90/KW/Year) because the DISCO is willing to pay a large premium to reduce risk.

Table 6 summarizes the average prices paid by the DISCO for different market specifications.

Table 5: GENCO's Annual Profit for New Peaking Capacity ($/KW/year)

Scenario	Base Case	High Spot Prices
Mean Price Spike	$90/MWh Price Spike: 50% chance if load> 8000MW	+$5000/MWh One day in ten years
Spot Market	14	21
Two Market Contracts	23	93
Two Market Contracts with Investment	90	-
Additional Premium above Two Market Contracts	**67** (90-23)	-

Table 6: Average Prices Paid by a DISCO Under High Spot Prices

	Average Price without Contracts ($/MWh)	Average Price with Two Market Contracts ($/MWh)	Average Price Increase ($/MWh)
Base Case	71	76	-
High Spot Prices	85	123	123-76=47

From Table 6, the average price paid by the DISCO with two market contracts in the Base Case (low price spikes) is $5/MWh higher than it is with no contracts ($76/MW compared to $71/MW). Using HSP, the average price with two market contracts is $38/MWh higher($123/MW compared to $85/MW), and the average price paid by the DISCO with two market contracts is over one and a half time as high as it is in the base case ($123/MWh versus $76/MWh). The price has to be increased by $47/MWh needed to "correct" the spot price in the base case.

The final step in the analysis is to evaluate the three alternative procedures by comparing the additional cost of adding 1GW of new peaking capacity to the total installed capacity. This is done by scaling the results presented in Tables 5-6 to 1000MW, and the choice of 1000MW represents the extra capacity needed for system adequacy to meet reliability standards. The results are summarized in Table 7. With a direct contract for the investment, the DISCOs must pay a premium of $67/KW/year=$67000/MW/year (Table 5) for the 1000MW of new capacity. The characteristics of the spot market are not affected in the short run and the total cost is 1000×67000 = $67 million/year.

Using the ICAP auction to cover the additional investment premium of $67000/MW/year implies that this payment is made to all installed capacity as well as to new peaking capacity (system adequacy is defined as 12000MW=120% of the maximum load). Since the new peaking capacity is

Table 7: Additional Cost of Adding 1GW of New Peaking Capacity ($million/year)

Annual Premium Above Market Contracts for 1 GW New Capacity (1)	Cost for Installed Capacity in ICAP Auction (2)	Additional Cost for All DISCOs (3)	Total Additional Cost (1)+(2)+(3)
Direct Investment Contract			
67	0	0	67
High ICAP payments (11GW Installed Capacity)			
67	737	0	804
High Spot Prices(7.7GW Load)			
0	0	382	382

only needed during the summer months, the ICAP auction must provide this payment for availability in the summer. The spot market is not affected in the short run and the total cost is $12000 \times 67000 = \$804$ million/year.

Allowing higher price spikes in HSP implies that the spot market is riskier for the DISCOs and the prices of forward contracts for peaking load are much higher. This increase in the average price is paid by all DISCOs for all on-peak load in the summer. Using HSP, the average price with two market contracts increases by $47/MWh (Table 6), and this increase is paid for the average on-peak load of 7700MW for 16×66 hours. The total cost is $7700 \times 47 \times 16 \times 66 = \$382$ million/year.

The overall conclusion from the results in Table 7 is that direct contracting is by far the least expensive way to ensure that generation adequacy is sufficient to meet reliability standards. Trying to correct market prices by making higher payments in the ICAP auction or by allowing higher price spikes increases the costs to the DISCOs by a factor of 12 and 5, respectively. Furthermore, paying most of these higher costs to the owners of installed capacity provides no guarantee that any new capacity will be built. In contrast, a direct contract is much less expensive, and the terms of the contract ensure that the needed capacity will be built in an appropriate location.

3.5 Average Cost and Average Price Curve

Under the current market design, the total cost of peaking units with low capacity factors cannot be recovered from the spot market. This argument can be supported by comparing the long-run average cost curve and average price curve for different capacity factors. The long-run average cost, the sum of the operating cost and the capital cost, is defined as the cost per operating hour for a peaking unit. For example, a peaking unit with marginal cost $100/MWh and capital cost

\$72000/MW/year that only operates ten days (240 hours) in the year has a long-run average cost of \$100/MWh+\$72000/240=\$400/MWh.

In order to calculate the long-run average cost, we made the following assumptions about annual capital cost and capacity factor.

1. For a plant with a low variable cost equal to \$15/MWh, the annual capital cost is \$155/KW, and the capital cost is recovered in THREE quarters. This plant is used if load > 5600MW.

2. For a plant with a high variable cost equal to \$60/MWh, the annual capital cost is \$85/KW, and the capital cost is recovered in ONE quarter. This plant is used if load >8240MW.

3. The variable costs and annual capital costs of other plants are linear functions of the load (position in the stack of installed capacity) from 5000MW to 10000MW, based on the values for the high cost and low cost plants above.

4. The capital cost recovered in the summer is a piecewise linear function of the load. For plants with annual capital costs > \$155/KW (<\$85/KW), 33%(100%) of the annual capital cost is recovered in the summer. For plants with annual capital costs between \$85/KW and \$155/KW, the percentage recovered is a linear interpolation of the load from 5600MW (33%) to 8240MW (100%).

5. The mean of the summer load is 7700MW and the standard deviation is 1100MW (a lognormal density is used to simulate load with (load - 5000MW) as the origin).

The average cost curve can be derived by the following formula,

$$AverageCost = \frac{\text{Annual Capital Cost} \times \text{ Shares Recovered in the Summer}}{\text{Summer Capacity Factor} \times \text{ Total Summer Hours}}$$

The average price curve can be derived from the following formula,

$$AveragePrice(D) = \frac{\sum_{i=D}^{D_{max}} (1 - CDF(i))E(p|i)}{\sum_{i=D}^{D_{max}} (1 - CDF(i))} \tag{19}$$

where CDF is the cumulative distribution function for load, i.e., $CDF(i) = \int_0^i f_D(x)dx$. And $E(p|i)$ is the expected price given load level i, i.e., $E(p|i) = \int_{C(i)}^{P_{cap}} \Phi_{P|D}(p|i)dp$, where $\Phi_{P|D}(p|i)$ is the conditional probability density function defined in Section 2.3.

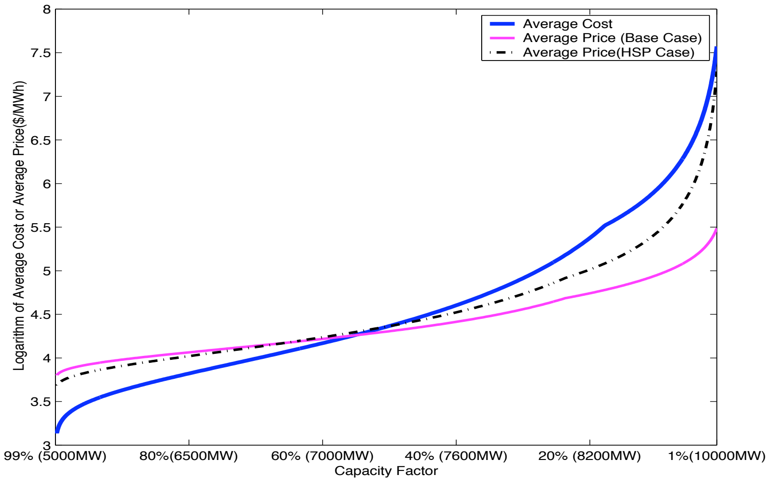

Figure 9: Simulated Average Cost and Average Price Curve

The average cost curve and average price curve are plotted in Figure 9. The horizontal axis denotes the summer capacity factor for each point of the stacked supply curve. For example, 60%(7000MW) means that a generating unit located at 7000MW on the stacked supply curve has a summer capacity factor of 60%. The vertical axis denotes the logarithm of average price or average cost. Figure 9 shows that peaking units with positions on the stacked supply curve below 71200MW can recover the total generating cost in the spot market. However, for peaking units with low capacity factors ($\leq$ 55%), the profit from the spot market is not high enough to recover the total average cost.

Under the HSP case, the average price curve is rotated and becomes steeper, and the shape is closer to the total average cost curve. This also makes the spot market more risky for the DISCOs, and consequently, they are willing to pay a higher risk premium. Hence, the capital cost of a new peaking unit (with low capacity factor) is recovered by combining the higher risk premium with the higher average spot price.

4 Summary and Conclusions

There are a number of characteristics of electricity markets that make it difficult to use standard economic models to link forward prices to spot prices. These are discussed in Section 1. Nevertheless, understanding the behavior of the forward prices of electricity is essential for analyzing investment decisions. Relatively long-term forward contracts will be needed by any investor to secure financing and commit to building new generation capacity. Unfortunately, the inherent risk of price spikes in deregulated markets and the difficulty of diversifying this risk make risk premiums high and difficult to predict. Section 2.1 explains the basic asymmetry of the relatively small risk faced by a generator (GENCO) and the relatively large risk faced by a buyer that has a mandate to meet load at a regulated rate(DISCO).

The first objective of the paper is to develop a more general framework for evaluating the financial risk in an electricity market. This framework is developed in Section 2.2 and it uses a Linex utility function that exhibits strong aversion to financial losses. This function represents an important improvement over other standard models. The new framework is used to derive the conditions for an optimum forward trade between a GENCO and a DISCO. The properties of a portfolio of a fixed price/fixed quantity contract for base load and a two-part contract for peaking load are discussed in Section 2.3.

The second, and most important, objective of the paper is to evaluate investment decisions, because there is growing concern among industry and government experts about relying on market forces to maintain the reliability of the supply system. System adequacy may not meet the necessary standards for reliability in some regions, such as New York City, if new generation capacity is not built soon. Section 3.1 shows how to determine the minimum level of profit needed to make an investment financially viable in a risky market.

The analytical framework is applied to data for the New York City region in Sections 3.2 and 3.3. The results show that profits from the spot market are far too low for a GENCO to invest in new peaking capacity. This is true even though the average price paid by a DISCO in a forward contracts is substantially higher than the average spot price. This result should be disturbing for people concerned about system reliability because the simulation assumes that spot prices are higher and price spikes occur more frequently than they actually do in the New York market.

The analysis in Section 3.4 considers three different procedures for increasing the incentives needed to initiate an investment in new peaking capacity. The first procedure requires the DISCOs to include a direct contract for new capacity in their portfolio of forward contracts. The second augments payments in a capacity auction (ICAP) to cover the capital cost of peaking capacity. The third allows price spikes to be higher in the spot market. Section 3.5 compare the long-run average cost curve and average price curve. The results show that peak units with low capacity factors cannot recover their total cost from the spot market.

Direct Contracts are much less expensive than the other two procedures. A premium is paid for each MW of new capacity, and the contract specifies that new capacity will be built. The other two procedures are much more expensive because in one case higher capacity payments are paid to all installed capacity, and in the other case, higher spot prices are paid for all on-peak load. In addition, there is no guarantee with either of these latter two procedures that any of the extra money paid to generators will be used to build new peaking capacity. In spite of the high cost of these two procedures, it is still not possible to rely on market forces to maintain the required standard of system adequacy. A contract to build the new capacity is the best way to ensure that system reliability will be maintained in the future as long as regulators continue to suppress price spikes.

This conclusion should be challenging for regulators and system operators. It implies that they must be very precise about projected shortages of capacity that threaten system reliability. It would be easy to slide into the same situation that occurred under regulation and require too much installed capacity. The starting point should be to announce that shortages of capacity are projected in the future. This would be similar to the traditional role played by NERC in providing a clearing house for information about new investment, retirements and load growth. The next step is more difficult. If a projected shortage of capacity becomes imminent, some form of intervention is required. Although our results imply that direct contracting for new capacity is an effective and relatively low cost procedure, there are many different ways to implement the investment contracts. Nevertheless, we believe that this approach to meeting reliability standards is much better than trying to modify prices in the market and putting the responsibility for maintaining reliability on Load Serving Entities (LSE).

Most researchers agree that there is a fundamental flaw in the current design of many deregulated markets. Most customers still pay a fixed rate for electricity, and as a result, load is not as responsive to price as it could or should be. The results of our analysis in Section 3.5 show very clearly how expensive peaking capacity can be. With high price spikes, the average price paid by a DISCO in forward contracts to cover the cost of new capacity is well over the regulated rate paid by customers. Passing on these high costs to some or all customers through critical peak pricing, for example, would result in a major improvement in the economic efficiency of the market.

In fairness to the Australian market, it should be pointed out that allowing high price spikes to occur may lead to lower average prices in the long run. This was not the case in our analysis because it dealt with short-run effects only, but it is an interesting topic for future research. There is no doubt that high price spikes do catch the attention of generators, LSEs and potential investors. The real question is whether this will lead to an acceptable level of investment and enough capacity in the right locations to meet reliability standards. However, it is unlikely that the increased price volatility needed to attract new investors would be politically acceptable in the USA. Under these conditions, it is important for regulators to take the full responsibility for maintaining system reliability. Regulating LSEs to meet a dubious rule-of-Thumb standard, such as contracting for load plus a reserve margin in an ICAP market, is unlikely to guarantee system reliability. When investment opportunities in transmission as well as generating are considered, it is clear that trying to "correct" market prices for real energy is a very unreliable way to ensure standards of system reliability and economic efficiency.

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APPENDIX

Table A1: Parameter Estimates: Daily on-peak Mean Temperature for NYC(1982-2003)

Regression Model	Parameter	Estimate	t ratio
	α_0	56.90	676.21
Mean (13)	α_1	-8.75	-73.51
	α_2	-20.54	-172.63
	β_0	2.67	106.16
Variance (14)	β_1	0.25	6.94
	β_2	0.40	11.29
	ϕ_1	1.48	26.42
ARMA (15)	ϕ_2	-0.68	-17.69
	ϕ_3	0.13	11.84
	θ_1	0.81	14.46

Table A2: Definition of Variables for the Load Model

Variable	Definition
L_t	logarithm of daily on-peak average load demand at time t
m_t	dummy variable whose value is 1 if it is Monday and 0 otherwise
tu_t	dummy variable whose value is 1 if it is Tuesday and 0 otherwise
w_t	dummy variable whose value is 1 if it is Wednesday and 0 otherwise
th_t	dummy variable whose value is 1 if it is Thursday and 0 otherwise
$holiday_t$	dummy variable whose value is 1 if it is Holiday and 0 otherwise
$trend_t$	time trend
cdd_t	cooling degree days, $cdd_t = max(T_t - 65, 0)$
	where T_t is the on-peak average temperature
hdd_t	heating degree days, $hdd_t = max(65 - T_t, 0)$
	where T_t is the on-peak average temperature
sin_{1t}	annual sine cycle
cos_{1t}	annual cosine cycle
sin_{2t}	semi-annual sine cycle
cos_{2t}	semi-annual cosine cycle
sin_{3t}	weekly sine cycle
cos_{3t}	weekly cosine cycle

Table A3: Parameter Estimates: Daily On-peak Average Load (16) for NYC (Jan 2001-Aug 2003)

Parameter	Variable	Estimate	t-ratio
ϕ_1	D_{t-1}	-0.185	-2.15
ϕ_2	D_{t-2}	0.575	11.08
ϕ_3	D_{t-3}	-0.082	-2.35
ϕ_4	D_{t-7}	0.116	3.44
μ	mean	8.71	1053.93
α_0	m_t	0.097	15.13
α_1	tu_t	-0.071	-6.69
α_2	w_t	-0.175	-16.45
α_3	th_t	-0.139	-21.71
α_4	$holiday_t$	-0.185	-26.78
α_5	$trend_t$	0.00003	2.68
α_6	cdd_t	0.012	33.78
α_7	hdd_t	0.001	4.78
α_8	sin_{1t}	-0.029	-6.00
α_9	cos_{1t}	-0.034	-6.06
α_{10}	sin_{2t}	0.042	9.27
α_{11}	cos_{2t}	0.029	6.57
α_{12}	sin_{3t}	0.043	7.94
α_{13}	cos_{3t}	-0.194	-42.34
θ_1	ε_{t-1}	-0.862	-10.66

Table A4: Parameter Estimates: Daily on-peak Average Price for NYC(Jan, 2001-Dec, 2002)

Regression Model	Parameter	Estimate	t-value
High Regime (17)	α_1	-42.29	-4.20
($R^2 = 0.64$)	α_0	5.21	4.71
Low Regime (18)	β_0	121.88	45.28
($R^2 = 0.63$)	β_1	-28.31	-2.77
	β_2	1.69	2.94