A Dynamic Analysis of a Demand Curve-Based Capacity Market Proposal: The PJM Reliability Pricing Model

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***Abstract*—Because of high generation adequacy standards in the power industry, some peaking capacity operates for a limited time during the year and may not receive sufficient energy revenues to meet its fixed costs. This is particularly true when energy prices are capped in order to mitigate market power. The northeastern U.S. independent system operators (ISOs) have responded to this issue by establishing capacity obligations for loads and markets for installed capacity, thus providing a capacity revenue stream to generators. The installed capacity (ICAP) markets in the northeastern U.S. markets are a response to this need for additional incentives to construct generation. The Federal Energy Regulatory Commission (FERC) has accepted the PJM Interconnection's (PJM) proposal to replace the present fixed ICAP requirement that is placed upon load serving entities (LSEs) with a demand curve-based system in which the ISO would be responsible for acquiring "residual" capacity on behalf of LSEs. The demand curve approach pays more when reserve margins are smaller and provides a reduced incentive for investment when installed reserves are above the target. Another goal is to make revenues more predictable for generators, making investment less costly and, ultimately, lowering prices for consumers. A dynamic representative agent model is presented for projecting effects upon reserve margins, generator profitability, and consumer costs and is applied to alternative demand curves proposed for the PJM market. The consumer costs resulting from a sloped demand curve are robustly lower compared to the present fixed requirement under a wide range of assumptions concerning behavior of generation owners, including risk attitudes, bidding behavior, and willingness to build capacity as a function of forecast profit. The cost savings arise from lower capital costs to generators due to reduced risk and risk premiums. Also, average installed capacity is less for the same level of reliability because of reduced fluctuations in installed reserves.**

***Index Terms*—Economics, power generation economics, power generation peaking capacity.**

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I. Introduction

RESTRUCTURED power markets around the globe have taken a range of approaches to ensure generation adequacy. Each approach has the goal of correcting market flaws that may prevent the energy market by itself from being able to achieve the optimal level of capacity. A debate is ongoing over whether separate capacity markets for electricity are needed for adequacy, and if they are, how they should be designed [18].

It has been asserted that two flaws in electricity markets mean that a capacity market is needed. First, there is no market in which direct customer valuation of reliability determines capacity additions; thus, a true market-based solution to reliability remains to be constructed [2], [11], [26]. Second, bid and price caps can lower profits so that peaking capacity is unprofitable if there is sufficient capacity to meet typical adequacy standards, such as an LOLP of one day in ten years [19]. Others, while admitting this, believe that creating capacity markets will only delay development of a sufficient demand response to eliminate the reliability problem and make electricity markets work like other markets [27]. It has also been argued that removing price caps and at the same time increasing demand participation is preferred to creating an additional market for artificial commodity (capacity). Indeed, some markets (e.g., Australia and the U.K.) exist without explicit caps and capacity markets (although Australia places limits on cumulative income from energy markets). However, the lack of demand response and the legacy of the California crisis means that caps will remain in place in the U.S. for the foreseeable future and that policy makers prefer the assurance of a resource adequacy requirement.[1]

The purpose of this paper is to present a dynamic simulation method that has been used to evaluate administrative "demand curves" for capacity that have been proposed for implementation in the PJM installed capacity market. The curves are evaluated in terms of adequacy, generator profit, and consumer costs. The next section of this paper describes the demand curve approach to capacity markets and outlines issues considered by the dynamic model summarized in Sections III and IV and detailed

[1]Hogan [16] and Oren [22] disagree with this position, arguing that it is feasible to transition to an energy-only market with very high or no price caps. Further, they believe that a "bottom-up" resource requirement based on call option or forward contract obligations [28] would better facilitate this transition than the administrative capacity markets used by the eastern ISOs. Here, we focus on the relative merits of different demand curves in "top-down" capacity markets, without claiming superiority to "bottom-up" systems.

in the Appendix. Section V summarizes an analysis of five possible demand curves for PJM.

II. Demand Curve Approach to Capacity Markets

Where a separate market for capacity has been created, either of two basic approaches has usually been adopted:[2]

- *price-based* capacity system in which all capacity is paid a fixed amount per MW;
- *quantity-based* capacity system, in which the amount of desired capacity is prespecified, and each LSE is obliged to provide a share proportional to its peak load in the form of generation capacity, load management, purchased capacity credits, or contracts for energy backed by physical assets.

In theory, if the optimal level of adequacy can be identified, then either a price- or quantity-based system can be used to achieve it [18], [26]. Elsewhere, we establish this result for a competitive market using a stylized model of generator entry into a market [15]. There, under certain simplifying assumptions, such as a long-run market characterized by a free-entry equilibrium and no market power, we show that price-based approaches, capacity requirements, and operating reserve requirements can each yield the socially optimal amount and mix of peaking and baseload capacity. Thus, any of these mechanisms can, in theory, correct the market flaw that energy prices do not reflect customer willingness to pay for reliability. This is done by providing capacity payments so that private investors' returns align with the social benefits of investment (based on a strong assumption that the target reserve is optimal).

More recently, the northeastern US ISOs have recommended a hybrid approach in which the ISO defines a sloping demand curve, describing the price to be paid for unforced capacity (i.e., capacity derated for expected forced outages) as a function of total capacity. This approach has characteristics of both quantity- and price-based systems. Just like the former system, there is a target reserve margin, and if there is a lot of excess capacity, the price is zero. However, like the latter system, there is still some payment for levels that exceed the required reserve margin (but not by too much), and the payments are less volatile from year to year than in a quantity-based system, decreasing risk to generators and perhaps stimulating more entry.

Fig. 1(b) shows an example of a sloped demand curve. Its x-axis is the total unforced capacity, while the y-axis is the payment per MW-year that the ISO makes to unforced capacity (i.e., capacity derated for expected forced outages). The ISO contracts for capacity on behalf of all load, recovering the cost as an uplift charge to consumers.[3]

Fig. 1(a) shows a "vertical" demand curve implied by a fixed ICAP requirement that can be contrasted with the sloped decurve Fig. 1(b). For the vertical case, the capacity obligation placed on LSEs determines the location of the vertical segment, while the deficiency penalty that LSEs pay for having inadequate reserves determines, *de facto*, the location of the horizontal portion. Such vertical curves tend to yield "bipolar"

[2]For reviews of capacity proposals and policy goals, see [4], [5], [8], and [14].

[3]However, bilateral contracts between capacity owners and LSEs can be used to hedge capacity price risks. LSEs can then offer the capacity they purchased to the auction. Thus, the ISO essentially procures the residual capacity.

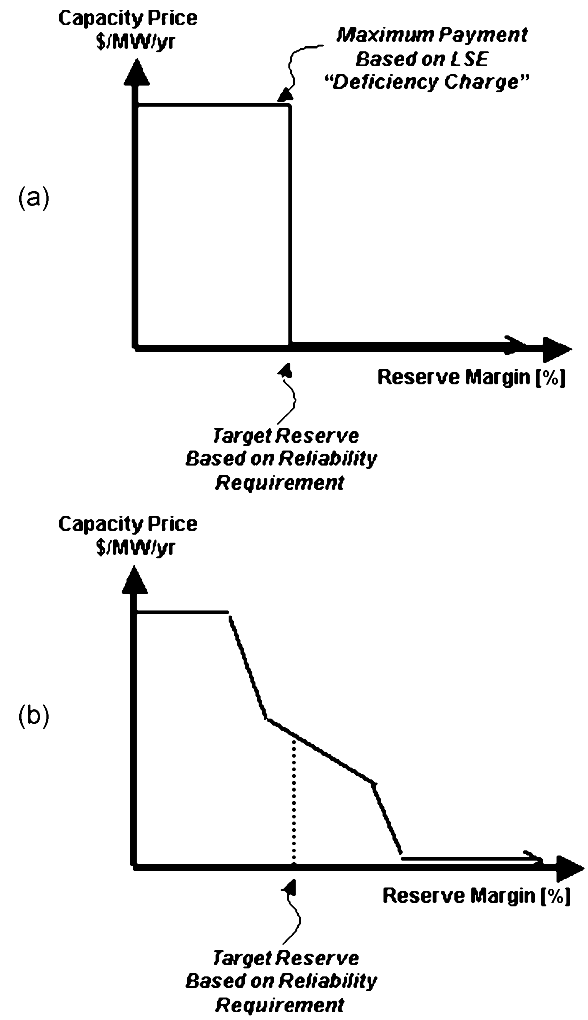

Fig. 1. Demand curves (capacity payments as a function of reserve margin). (a) "Vertical" case (present PJM system). (b) Downward sloping case.

prices that are either close to zero or near the deficiency charge. In contrast, the simulations of this paper show that sloped demand curves yield a continuum of less volatile prices.

Sloped curves have been seriously considered in the northeastern U.S. markets. The NYISO has had a demand curve-based ICAP system since 2003, and it has survived court challenges. Consistent with our simulations, the NYISO curve has indeed resulted in more stable and predictable capacity prices. Under the previous vertical curve, prices tended to be near zero unless a shortage developed, in which case the price jumped to the deficiency charge [21]. Meanwhile, ISO-NE had filed a locational ICAP (LICAP) system [7] for approval at FERC, although the demand-curve proposal was significantly modified in settlement. The PJM reliability pricing model (RPM) is the latest demand-curve-based capacity market to be filed (August 2005), and the general concept received FERC approval in April 2006.

Some issues in designing demand-curve systems include the following.

1) *Lead time for the obligation* (e.g., month-ahead in the originally proposed ISO-NE LICAP system versus the four years proposed by PJM). Of course, this is also an issue with capacity mechanisms that do not use a demand curve.

2) *Location, slope, and height of the demand curve*. For example, NYISO has one downward sloping segment, while ISO-NE's originally proposed curve had two downward sloping segments. The location and height of the curve should be set so that it elicits sufficient investment from the market to attain the target reserve with some specified reliability. Another, less desirable rule for determining curve location is to center it at the target reserve and then set the capacity price at that margin high enough to cover the costs of a new peaker [usually a "benchmark" combustion turbine (CT)], net of any gross margin it would receive from the energy and ancillary services (E/AS) markets. The maximum price is usually set at some multiple of the cost of a turbine.
3) *Adjustments for gross margins earned from the E/AS by a benchmark turbine*. ("Gross margin" is an accounting term that is defined as revenues minus variable costs.) One approach is to estimate the average E/AS margin that would be earned over several years and then lower the demand curve by that value (PJM, NYISO). As an alternative, the capacity payment in a given year could equal the value from the curve, minus the actual gross margin that would be earned in that year by a benchmark turbine (as proposed in [7]), with a constraint that the payment cannot be negative. The intent of the latter system is to stabilize the overall net revenue received by peaking plants (E/AS margin plus capacity payments), which can lower risk and market power [7].
4) *Rules for forfeiting ICAP payments*. The intent of such rules is to motivate generators to be available when they are needed. PJM proposes to pay based on unforced capacity, while the proposed ISO-NE system instead would have adjusted payments in a given year for unavailability during critical hours of the same year [7].
5) *Demand-side participation*. In ICAP systems, load management programs can generally earn ICAP credits or can lower the obligation of LSEs to obtain such credits. For instance, air conditioner and water heater load control programs receive such credits in the PJM system. The specific procedures for estimating load impacts and for bidding in such programs are an important design feature.

We next summarize an approach for assessing the potential performance of alternative capacity demand curves.

III. Overview of the Dynamic Analysis

The object of the dynamic model is to assess how alternative assumptions concerning investor behavior could affect the performance of different shapes and locations for the demand curve, considering the dynamic response of the market to construction incentives. Three sets of indexes are calculated for each curve: generation adequacy; generator revenues and profits; and consumer payments.

The idea is that capacity construction is a dynamic process with lags (due to construction lead times), short-sightedness (additions are based on recent E/AS market behavior, rather than perfect price forecasts), and uncertain load growth.[4] Thus, for instance, if it takes four years to bring a CT on line, the amount of turbine capacity installed in year y might be assumed to be some function of profits in, say, years $y-7$ through $y-4$. Profits, of course, are based on gross margins earned in the E/AS markets and any capacity payments.

Such a process could result in an unstable system exhibiting overshoot-type dynamics [10]. Merchant generation might overreact to high profit opportunities, yielding a glut of capacity that then depresses prices, which then throttles capacity construction, leading subsequently to a shortage and so on. Load uncertainty can exacerbate instabilities. Variable economic growth can cause the growth in peak load (weather normalized) to deviate from the expected value (1.7%/yr for PJM), implying that realized reserve margins may diverge from those forecast in an advance capacity auction. Further, weather adds volatility to E/AS gross margins. The resulting unstable profits can affect generators' willingness to invest.

Of course, such overshoot dynamics will be less severe if investors have rational expectations. There is however anecdotal evidence of myopic behavior of the type just described. This is unsurprising given that rational expectations take time to form and the market design is new and changing.

An objective of the design of a capacity market would be to dampen such cycles while maintaining system adequacy and minimizing costs to consumers. It is reasonable to expect that the slope and location of a demand curve will affect the stability of the capacity market and, ultimately, prices and reliability. Predictability and stability of generator profits might also be of concern. Our analysis focuses on those objectives. Other objectives might be 1) to avoid providing artificial opportunities to exercise market power, 2) to motivate generators to reveal their true costs, 3) to promote long-term contracting and hedging by LSEs, and 4) to prevent free-riding of LSEs on resources of other retailers [e.g., 5]. Those objectives are not considered here.

Our model is intended to be as simple as possible a representation of the fundamental processes that are affected by the demand curve and that affect capacity market instability:

- uncertain load growth and E/AS revenues;
- generator risk aversion and short-sightedness;
- generator willingness to invest that increases as a function of forecast profit, adjusted for risk.

The model represents these processes using simple functional forms with a minimum of parameters to facilitate alternative assumptions and insight. In general, invoking Occam's razor, no more complex relationships should be used in a model than is necessary, unless the additional complexity demonstrably in-

[4]Others have based simulation models of generation capacity on such a dynamic process (Botterud *et al.* [3], deVries [8], Ford [10], Ilic *et al.* [17], Kadoya *et al.* [20], Sanchez *et al.* [25]). Our analysis is unique because it focuses on the dynamics of peaking plant investment in capacity markets with demand curves under uncertainty due to weather and economic growth. Kadoya *et al.* [20] also consider the northeastern U.S. markets, while modeling baseload as well as peaking capacity, but do not consider demand curves for capacity.

Other authors have undertaken more general analyses of forward versus spot commitments in electricity markets. For instance, Bessembinder and Lemmon [1] describe how equilibrium forward price premiums can be affected by various factors, and Longstaff and Wang [9] empirically estimate these premiums for the PJM market.

creases the model's realism. Another desirable model characteristic is that, in the case of no uncertainty and risk neutrality, the model yields an equilibrium solution of enough capacity being added in each year to meet load growth, with revenues equaling costs. Our model satisfies this condition.

Model outputs include the following three sets of indexes of interest.

1) *Resource adequacy indexes*. One is the forecast installed reserve margin, including its mean and year-to-year standard deviation. Another is the fraction of years in which the forecast margin exceeds the target.
2) *Indexes of generator revenues and profits*. These include averages for benchmark CT profit, capacity price, and E/AS revenues, as well as year-to-year standard deviations. These are expressed as $/installed MW/yr (derated). In addition, we show internal rates of return (IRR) on investor capital (as %/yr). Because PJM's CT cost assumptions ($61/installed kW/yr levelized real) are based on a nominal IRR of 12% (reflecting after-tax costs of equity capital in a relatively stable regulated rate-of-return environment), then an economic profit of $0/kW-yr in the results presented later translate into an IRR of 12%.
3) *Consumer cost*. We calculate the mean and standard deviation (year-to-year) of customer payments ($/peak MW/year) for capacity plus scarcity rents paid to all capacity. We assume that other payments by consumers (energy produced during nonscarcity periods, wires charges, customer charges) are unaffected by the capacity demand curve. A higher average cost can occur if chronically low reserve margins yield high capacity prices and scarcity payments. Such conditions could persist if high market risks make investors reluctant to construct unless average returns are large.

IV. Model Logic and Key Assumptions

A. Summary of Model Logic

The model is a discrete time simulation with an annual time step. For simplicity, a single representative agent is used whose knowledge and preferences do not change over time; alternatively, models with multiple learning agents could be used, but that would conflict with the goal of simplicity. Fig. 2 shows the logical flow of the model.

In the PJM system, an auction for capacity to be available in year y must take place at $y-4$, four years before that time. In summary, the following steps are executed in each year.

- Given the previous year $y-5$'s weather-normalized peak load, and assuming random economic growth, the model first generates a random weather-normalized peak for year $y-4$. The simulation then generates an actual peak load, accounting for random weather. E/AS gross margin is then calculated for a benchmark CT (having fixed annual cost FC) for year $y-4$. This margin is a function of the actual peak load and reserve margin in that year. Based on PJM experience, tighter actual margins are associated with higher E/AS earnings. The E/AS gross margin plus the capacity revenues for that year (determined in a previous auction) minus FC define the benchmark turbine's profit. Then a forecast is made of the weather-normalized peak four years in the future (year y); this forecast is the basis of the demand curve in the auction held in year $y-4$.

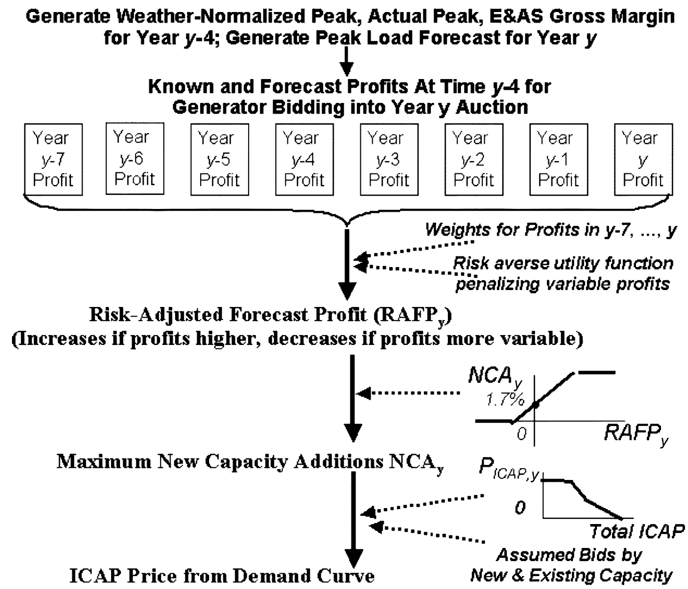

Fig. 2. Flowchart showing steps of simulation.

- Next, companies who might build new generation assess profits for a CT in years $y-7$ to y (see Fig. 2). (Fewer or greater numbers of years could be chosen, but the relative performance of different demand curves would not be greatly affected.) Profits for some of those years ($y-7$ to $y-4$) are assumed to be already known, since those years have already passed ($y-7$ to $y-5$) or are in process ($y-4$) and can be fairly accurately projected. Profits for future years ($y-3$ to y) are not known, since E/AS revenues depend on loads, which in turn are uncertain because of varying economic growth and weather. The capacity price is known for $y-3$ to $y-1$ (due to prior auctions) but has to be estimated for this year's auction (y), which has not yet occurred.
- Then, given those profits, a risk-adjusted forecast profit $RAFP_y$ is calculated, which requires two inputs. One is a set of weights to be attached to the profits in years $y-7$ to y; for example, more weight might be given to recent profits. The other is a "utility function" that incorporates attitudes toward risk. Such a function penalizes bad outcomes in such a way that if there are two distributions of profits with the same average value, the more variable profit stream will be less attractive.
- In the next step, $RAFP_y$ is translated into a maximum amount of new capacity NCA_y that generators are willing to construct; we assume that higher risk-adjusted profits will increase the amount of capacity that generators are willing to build. The NCA-RAFP function in Fig. 2 assumes 1.7%/yr average load growth and a ceiling on capacity additions. This average growth is the value that PJM has forecast for the next few years based on its forecasting models.

- Then a supply curve for capacity is constructed, based on the amounts of existing and potential new capacity and the assumed prices that each would bid. This supply curve is then combined with the demand curve to yield a capacity price and committed amount of new capacity for year y. This committed amount might be less than the maximum amount if new capacity is assumed to bid a positive price.

After these steps are executed, the simulation then moves to the next year, and the process is repeated.

Because the model randomly samples economic growth and weather, good modeling practice requires that a large sample of years be simulated in order to obtain reliable estimates of the average long-run performance that are unaffected by sample error. Twenty-five simulations of 100 years apiece are run for each demand curve and set of assumptions tested. This gives a sample size of 2500 years, allowing calculation of the long-run average and standard deviation of each performance index.

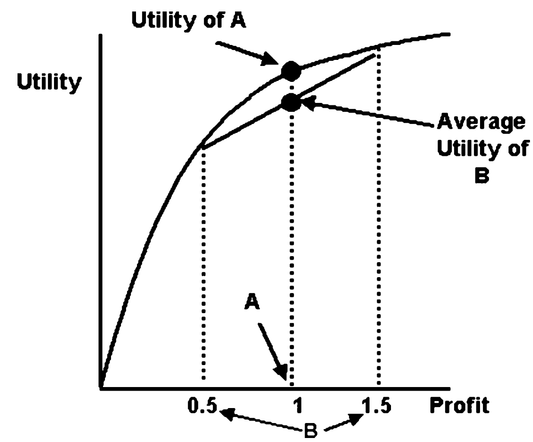

Fig. 3. Risk-averse utility function results in lower average utility for riskier alternatives.

B. Key Assumptions

The key assumptions that drive the model are that generators invest more if profits are higher; generators invest less if profits have higher variance; and that generators base forecasts of profit on past profits. Under these assumptions, if one demand curve results in more stable profits than another, then not as much average profit is required to encourage investment. An additional important assumption is that the analysis can focus on peaking capacity. Each assumption is discussed below.

Investment Responds to Higher Profits: Although this might seem obvious, it is possible that investment could be limited instead by siting or other regulatory restrictions. We assume that this is not so and that within a relatively wide range of profits investment, increases with expected profit.

Risk Aversion: Investment in generation is assumed to increase if expected profits increase and/or if the variance in profits decreases; thus, generators are assumed to be "risk averse," preferring more certain profits over less certain profits, if the average profit is the same. As mentioned above, the model adopts a simple device to represent these preferences: the utility function. The utility function is an increasing and concave function that reflects an assumed risk-averse attitude; this is a standard method used in decision analysis and economics to represent risk acceptance behavior by individuals and companies. Different profit streams are compared by calculating the expected value of the utility function; the more concave the function, the more risk averse we assume generating companies to be and the more that undesired outcomes and profit variations are penalized. On the other hand, a linear utility function represents risk neutrality, where only expected profit matters. A negative exponential form, which is standard in decision analysis, is used so that the risk attitude can be summarized by a single risk aversion parameter, as the Appendix explains.

Fig. 3 illustrates how a risk-averse utility function penalizes riskier profit streams. The higher the average utility, the more attractive investors are assumed to view an investment opportunity. Comparing two distributions of profits—distribution A, which has \$1 occurring for sure, and distribution B, which has a 50:50 chance of \$0.50 and \$1.50—a concave form of the utility function means that the average utility of B is lower than the utility of A. So the riskier investment is less desirable, even though its average profit is the same.

As explained above, given the average and variation of recent profits, the model then calculates their expected utility; then this utility value is translated into the risk-adjusted forecast profit (RAFP), which is a certain profit whose utility is the same as the calculated expected value. Consistent with our assumption that higher profits or lower risk yield more investment, an increasing function then translates RAFP into an amount of investment that generators are willing to make—maximum new capacity additions (NCAs).

Profit Forecasts Based on Past Profits: In general, generating companies base investments upon forecasts of future prices and profits, using either market simulation models (combining forecasts of loads, fuel prices, and capacities), statistical models, or forward price curves. Since past history is a critical input to those models, future profit forecasts are an implicit function of past prices and profits. If past profits are higher, forecast profits will generally be so, too. For simplicity, this implicit relationship is represented explicitly in our model by assuming that forecast future profits are monotonically increasing in past profits, so that willingness to invest (an increasing function of forecast profits) can be represented as an increasing function of past profits.

Focus on Peaking Capacity: More sophisticated models (such as [15]) could consider investments in baseload and cycling capacity, in addition to peaking capacity. Our analysis focuses on entry decisions by peaking turbines based on the assumption that the price of capacity will be driven by the cost of such turbines, net of their gross margins in the E/AS market, while other types of capacity receive most of their gross margins from the E/AS market. We have also conducted simulations of long-run equilibrium entry of coal plants, combined cycle facilities, and peaking plants for the PJM system, based on the methodology in [15]. Justifying our focus here on turbine investments, it turns out that those simulations show that the amount and mix of nonpeaking capacity is not affected by the required reserve margin or the price of ICAP. Only the amount of peaking capacity is affected. In fact, it can be proven that under the long-run free-entry assumptions made in

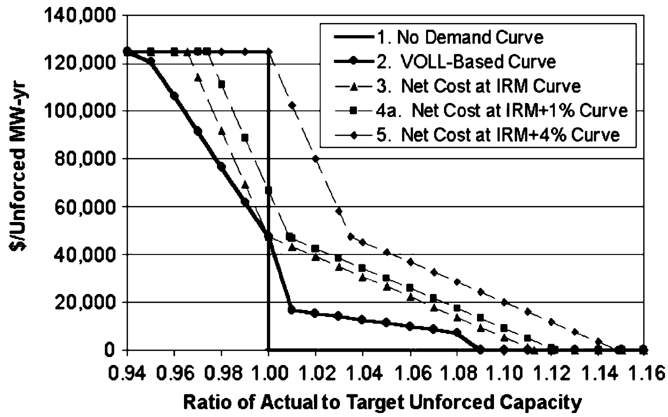

Fig. 4. Alternative demand curves considered for PJM RPM.

[15] that indeed the amount and mix of nonpeaking capacity is unaffected in the long run by the design of the capacity market. However, we do assume that all generating units receive capacity payments, and we calculate consumer costs on that basis. In reality, it is possible that in some years, capacity additions for other types of plant will be undertaken while no turbines are being added. For example, if there are large shifts in relative fuel prices, as in the 1970s, generation additions beyond what are needed to meet reserve margin requirements might be justified in order to displace uneconomic fuels in the existing generation mix. For simplicity, we assume that these conditions are relatively infrequent and that if capacity is being added, at least some of it will be in the form of CTs, whose forecast profits will be largely made up of ICAP revenues.

V. Results for PJM "Reliability Pricing Model"

A. Demand Curves Considered

Five demand curves are considered (see Fig. 4), showing the price paid to accepted capacity bids on a \$/unforced kW/yr basis (i.e., adjusted for expected forced outages). They are expressed as a function of the ratio of actual unforced capacity to PJM's unforced capacity target (an LOLP of one day in ten years), equivalent to an installed reserve margin of 15%.

The rationale for considering these five curves is as follows. Curve 2 represents the present situation and is included so that the improvement that might be anticipated from alternative curves can be estimated. Curve 2 is an early proposal considered by PJM that attempted to consider the value of loss load, but its poor performance led it to being dropped later. Curve 3 is a later proposal that was broadly modeled after the ISO-NE proposal. However, in order to attain a higher probability of meeting the target reserve, additional curves were later considered that shifted Curve 3 to the right (Curves 4 and 5). A number of other curves with various modifications suggested by stakeholders have also been evaluated [13], but this set of curves is representative of the results that have been obtained.

The description of each of the curves follows.

1) *No Demand Curve*. When values of forecast reserves are short of the target, the "no" or "vertical" demand curve case gives a capacity payment that is twice the fixed cost of a turbine minus the mean E/AS gross margin (\$28 000/MW/yr for 1999–2004). This is like the present PJM system in which LSEs are willing to pay up to their deficiency penalty if they are short of capacity credits, while if credits are in surplus, we assume that LSEs are unwilling to buy excess credits. The maximum price is assumed to be twice the levelized capital and fixed O&M cost of a turbine (in nominal \$: \$77 400/unforced MW/yr), minus an allowance for the E/AS gross margin.
2) *VOLL-Based Curve*. A demand curve originally proposed by PJM in August 2004 was based upon an approximation of how the expected value of lost load (VOLL) changes when reserve margins diverge from PJM's target. Instead of the cost of incremental capacity, this curve attempts to approximate the value to consumers of changes in unserved load.
3) *Curve with New Entry Net Cost at IRM*. As shown in Fig. 4, this is a sloped demand curve with several segments: a) a horizontal segment with a price approximately equal to two times the fixed cost per unforced kW of a turbine if the reserves are less than 96% of the target, minus the average E/AS gross margin; and b) two linear downward sloping segments, with the right-hand one having a shallower slope ($= -420\,000$ \$/MW-yr). The location where the slope changes is at a reserve margin equal to the target, and a price equal to the levelized nominal cost of the turbine minus the mean E/AS gross margin. As a result, if capacity hits the target exactly, then the payment equals the difference between the benchmark CT's fixed cost and its average E/AS gross margin.
4) *Curve with New Entry Net Cost at IRM* $+1\%$. Curve 4a shifts Curve 3 to the right by 1% (in installed capacity terms). Thus, at any reserve margin, capacity will receive an equal or higher payment than in Curve 3. This gives additional incentive to invest in generation, thereby increasing reserve margins. PJM recommended a variant of this curve (4b, not shown in Fig. 4) in its August 2005 FERC filing. This variant truncated the right-hand tail to zero at a ratio of 1.043 as a response to some stakeholder concerns that payments not be made if the reserve margin is very high. (As shown in Table I, this truncation made little difference in the results, so we limit our discussion to Curve 4a.)
5) *Curve with New Entry Net Cost at IRM* $+4\%$. This is a version of Curve 3, except moved 4% to the right.

B. Base Case Results

Table I shows the base case results, from which we draw the following conclusions concerning the relative performance of the different curves. First, the "no demand curve" case (Curve 1) has an average reserve margin that is less than the target (-0.44% less, to be exact), even though the vertical portion of the curve is located precisely at the target. Also, Curve 1's standard deviation for the reserve margin (1.92%) is double or more the values for the other curves. This greater risk is illustrated in Fig. 5. That figure shows a time series of forecast reserves for sample 100 year simulations for Curves 1 and 4. The curve shows that forecast reserve margins for the "no demand curve"

TABLE I
SUMMARY OF PERFORMANCE OF SIX CAPACITY DEMAND CURVES CONSIDERED BY PJM (STANDARD DEVIATIONS IN PARENTHESES)

Curve	Forecast Reserve Indices		Generation Profit, [$/kW/yr] /Internal Rate of Return (only profit standard deviation shown)	Components of Generation Revenue			Consumer Payments for Scarcity + Capacity, divided by Peak Load $/Peak kW/yr
	% Yrs Forecast Reserve Exceeds Target Reserve	Average % By Which Forecast Reserve Exceeds Target Reserve		Scarcity Revenue (Variable Portion of E/AS) $/kW/yr	E/AS Fixed Revenue $/kW/yr	Capacity Payment $/kW/yr	
1. No Demand Curve	39	-0.44 (1.92)	66/35.3% (113)	47 (85)	10	70 (57)	129 (121)
2. Curve, Based on VOLL	54	0.06 (0.74)	25/21.2% (73)	37 (70)	10	39 (14)	84 (78)
3. New Entry Net Cost at IRM	92	1.23 (0.88)	15/17.5% (53)	26 (52)	10	40 (4)	74 (55)
4a. New Entry Net Cost at IRM+1% (Original)	99	1.82 (0.89)	12/16.6% (45)	21 (44)	10	42 (5)	71 (47)
4b. New Entry Net Cost at IRM+1% (Truncated)	98	1.79 (0.90)	12/16.6% (46)	21 (44)	10	42 (7)	71 (48)
5. New Entry Net Cost at IRM+4%	100	3.87 (0.95)	7/14.7% (26)	11 (23)	10	47 (9)	67 (27)

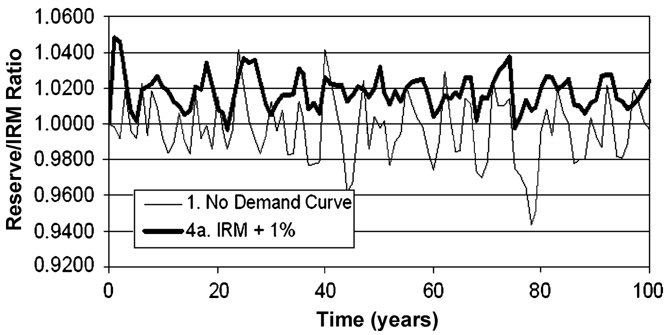

Fig. 5. Example time series from single simulation of ratios of forecast unforced reserve margin to target unforced reserve, curve 1 (no demand curve) and curve 4a (original curve $\mathrm{IRM} + 1\%$).

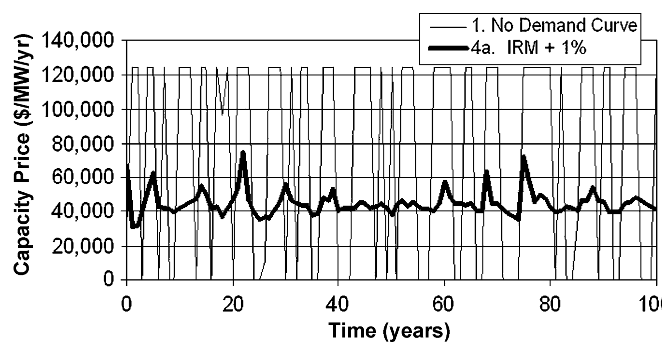

Fig. 6. Example time series of capacity prices from single simulation, curve 1 (no demand curve) and curve 4a (original curve $\mathrm{IRM} + 1\%$).

fluctuate between 94% and 104% of the IRM, while those for Curve 4 not only meet or exceed the target more often but also have a narrower range (100%–105%).

Further, average profits and consumer payments are higher for Curve 1 (no demand curve) than for the other curves. Required profits are higher because risks to investors are greater; by assumption, risk-averse investors demand higher average returns in order to compensate for higher risks, and so, on average, generators must earn higher profits if they are to invest. Hence, generators who are in the market earn higher average profits. This does not mean that they are better off; rather, more profit is needed to offset the greater risks, reflected in higher capital costs (note the higher IRRs in Table I).

Curve 1's greater risk is indicated by the standard deviation of profits ($113 000/peak MW/yr), which is considerably larger than for the other curves. This greater variation occurs in part because the vertical curve results in more year-to-year variation in capacity revenue; in essence, capacity prices bounce between zero and the maximum level on the curve ($124 700/MW/yr; see Fig. 4) depending on whether existing capacity plus new additions is greater or less than the target. Fig. 6 illustrates the volatility in capacity payments from a 100-year simulation of Curve 1. Thus, that curve has a large standard deviation for ICAP revenues ($57 000/MW/yr, the highest among all curves; see Table I). In contrast, Fig. 6 shows that the capacity payments are much more stable for Curve 4.

However, fluctuating ICAP prices are not the only cause of volatile profit for the vertical demand curve. Energy and ancillary service gross margins also vary the most for Curve 1 (see Table I). The reason is that fluctuating forecast reserves mean that there are a number of years of low reserves; hot weather and/or higher than anticipated economic growth can push actual reserves even lower. At such times, E/AS gross margins can be high (see Fig. 8 in the Appendix).

Because reserves fluctuate more for Curve 1 than for other curves, the resulting E/AS vary more. Fig. 7 shows two sample time series of generator profits per MW of turbine capacity (unforced), one for Curve 1 and the other for Curve 4a. The Curve 1 time series exhibits higher average profit but also higher variation than the Curve 4 series. The Curve 1 has a higher average because a higher expected profit is required to make up for the greater variation in order to induce investment by the generators, who we assume are risk averse. In a nutshell: the steepness of the vertical curve induces more variation in capacity payments (see Fig. 6), which translates in turn into higher variation in profits; in a world of risk-averse investors assumed here, this greater risk must be compensated for by higher average returns in order to induce investment.

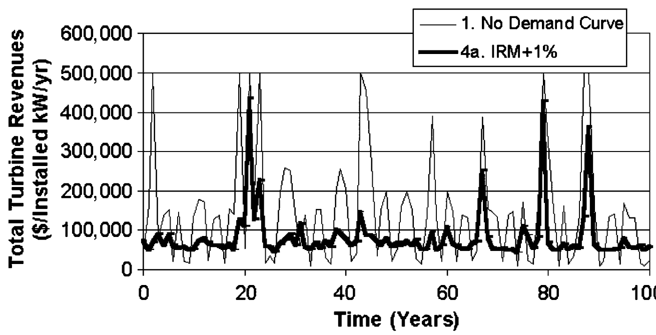

Fig. 7. Example time series of CT revenues from single simulation, curve 1 (no demand curve) and curve 4a (original curve $\mathrm{IRM}+1\%$).

Because Curve 1 (no demand curve) results in high consumer costs and relatively low reserve margins, the other curves appear more attractive by these metrics. Improved performance of the "no curve" case occurs if it is shifted to the right, which increases reserve margins and somewhat lowers risks to investors and costs to consumers, or if it is assumed that new generation submits a nonzero bid. We document these and other sensitivity analyses elsewhere [12]. However, the lack of a slope for Curve 1 causes relatively high variations in capacity prices and, thus, profits to persist under alternative assumptions. As a result, required profits remain higher than for the other curves and so do consumer costs. Thus, we conclude that sloped curves are more desirable for consumers.

Comparing just the sloped curves (Curves 2–5; see Fig. 4), they differ in their reserve margins, generator profits, and consumer costs. Curves 2 and 3 result in lower probabilities of meeting or exceeding the IRM, as well as higher consumer costs and thus less desirability than Curves 4–5, which are variants of Curve 3, in which the curve has been shifted to the right.

As the curves shift to the right, a greater proportion of the gross margin for generators comes from the capacity market and less from E/AS scarcity revenues. The standard deviations in Table I indicate that capacity revenues tend to be less volatile for Curves 2–5 (varying by only a few tens of dollars per kW per year) relative to E/AS margin (which can vary tenfold or more, depending on weather and other variations). As a result, shifting curves to the right lowers risks for generators, so the profit required to justify investment is smaller (note the lower equilibrium profit for Curves 4 and 5 compared to Curves 2 and 3). The lower required profit translates directly into lower consumer payments for Curves 4 and 5 compared to Curves 2 and 3.

C. Sensitivity Analysis Results

Extensive sensitivity analyses have been performed of our assumptions [12], [13]. The cases considered include:

1) demand curve changes (maximum price and slopes, truncation of the right-hand tail);
2) behavioral assumptions, including risk aversion (from risk neutrality to extreme risk aversion), amount of turbine capacity added when profits are high, bid prices for existing and new capacity (from zero to about two-thirds the cost of new turbines), and forecast weights (more or less weight on recent profits);
3) lower energy/ancillary service gross margins;
4) shorter time horizon for auction (same year, like NYISO and ISO-NE, rather than four-year ahead);
5) larger variation of growth rates in weather-normalized load due to economic growth uncertainty.

In general, the performance of Curve 1 (no demand curve) is more sensitive to these assumptions than the sloped demand curves, sometimes dramatically so. For instance, more risk aversion causes generation owners to require higher profits to enter, while positive bids for capacity tend to somewhat stabilize capacity prices. These effects are greater for Curve 1.

Yet under no assumptions is the "no demand curve" case preferable to the sloped curves, in terms of reserve margins or consumer payments. Although the conclusion regarding the desirability of sloped curves (especially Curves 4 and 5) relative to Curve 1 (no demand curve) is robust with respect to these assumptions, the precise financial consequences (capacity prices, generator profits, and consumer payments) do depend strongly on the assumptions made. Therefore, the conclusion we draw is that there is significant uncertainty regarding the future effects of capacity mechanisms on consumers but that risks are lower if a sloped demand curve is used.

VI. Conclusion

Dynamic models can be useful for assessing capacity market designs. Simplicity is a virtue in developing such models because it facilitates sensitivity analysis of behavioral and other assumptions. The analysis of the proposed RPM reforms to the PJM capacity market indicates that the risk reducing features of capacity demand curves can simultaneously lower costs to consumers and increase investment relative to the vertical demand curve implied by the present PJM ICAP system. This conclusion is robust with respect to changes in assumptions.

Future modeling work could address the locational aspect of the proposed RPM system, in which capacity short subregions of PJM would be allowed to have higher capacity prices. This work could also address uncertainties in capacity costs and entry due to changes in fuel prices and technology and the performance of different approaches to adapt the demand curve to new knowledge.

Appendix
Model Description

This Appendix describes the model's numerical assumptions and calculation procedures in some detail.

The model requires a number of parameters that characterize the market design, load, system reliability, E/AS gross margins, and generator responses to incentives.

Inflation: All calculations are made in real (uninflated) dollars. All capital and operating costs and demand curves are assumed to escalate at the general rate of inflation.

Market Design Parameters: These include the following.

1) Parameters of the demand function(s) for capacity. Let $P_{ICAP}(r_{F,y})$ be the price [$/MW/yr] paid for unforced capacity in year y as a function of unforced capacity reserve $r_{F,y}$. The F subscript indicates that the reserve margin is calculated using the load forecast at $y-4$, the time of the auction.

2) The extent to which actual gross margins earned in the E/AS markets in a y are deducted from capacity payments. The model can accommodate the ISO-NE system (which deducts such margins), but we do not discuss that feature further.

To focus on general resource adequacy issues, the following additional aspects of capacity market design are not considered: capacity payments differentiated by operating flexibility or location; backstop mechanisms if reserve margins are unacceptably low for several years; and administrative adjustments to demand curves that are made in response to new information about capacity costs and revenues from E/AS markets.

Load Parameters: Load is summarized by the annual MW peak load in year y, called L_y in the model. Three types of loads are considered: *forecast* peak load $L_{F,y}$, *weather-normalized* peak load $L_{WN,y}$, and *actual* peak load $L_{A,y}$.

The growth in weather-normalized load $L_{WN,y}$ is assumed to average 1.7%/yr. This average growth is the value that PJM has forecast for next few years based on its econometric analyses [24]. A normally distributed random component with a standard deviation of 1% is added to the 1.7% average growth rate in order to represent random economic growth. Thus, the simulation is a Monte Carlo simulation, in which random trajectories of $L_{WN,y}$ are drawn as follows:

$$L_{WN,y+1} = L_{WN,y}(1.017 + ERR_{WN}) \tag{1}$$

where ERR_{WN} is an independently distributed normal random variable with mean zero and standard deviation of 1%, consistent with PJM experience. The forecast peak load in year y is related to the actual load in year $y-4$ by the following forecasting formula:

$$L_{F,y+4} = L_{WN,y}(1.017)^4. \tag{2}$$

This assumes that four-year-ahead forecasts are used in the auction and that 1.7%/yr load growth is the basis of the forecast.

The actual peak load in year y equals the weather-normalized peak plus an error reflecting year-to-year weather variations. Analysis of 1995–2003 data for PJM and ISO-NE shows that the ratio of actual to weather-normalized annual peaks has a standard deviation of about 4%. The formula is

$$L_{A,y} = L_{WN,y}(1 + ERR_A) \tag{3}$$

where ERR_A is an independently distributed normal error with mean zero and standard deviation of approximately 4%.

Reserve Margins: Random economic growth and weather variability can result in volatility in installed reserve margins and E/AS gross margins. The actual reserve margin $r_{A,y}$ in a particular year is calculated as follows:

$$r_{A,y} = (1 - FOR)X_y/L_{A,y} \tag{4}$$

where X_y is the installed capacity in the given year, and FOR is its average forced outage rate. Forecast reserve margin, which is the basis of the capacity payment (see Fig. 2), is calculated from forecast load as

$$r_{F,y} = (1 - FOR)X_y/L_{F,y}. \tag{5}$$

Generation Costs and Revenues: The model focuses on CT additions, and we do not represent investment decisions concerning baseload and cycling capacity. More sophisticated assumptions about entry of other types of capacity can be made, but to simplify the simulations, we presume that at least some of the incremental capacity is provided by benchmark CT capacity. This is based on the assumption that the price of capacity will be driven by the cost of turbines, net of their gross margins in the E/AS market, while other types of capacity receive most of their gross margins from the E/AS market. Elsewhere, long-run equilibrium entry of coal plants, combined cycle facilities, and peaking plants for the PJM system has been simulated [15]. Justifying our present focus on turbine investments, it turns out that those simulations show that the amount and mix of nonpeaking capacity is unaffected by the capacity market design, required reserve margin, or price of capacity. Only the amount of peaking capacity is affected. Nevertheless, all generating units receive capacity payments, and consumer costs are calculated on that basis.

In reality, it is possible that in some years, capacity additions for other types of plant will be undertaken while no turbines are being added. For example, if there are large shifts in relative fuel prices, as in the 1970s, generation additions beyond what is needed to meet reserve margin requirements might be justified in order to displace uneconomic fuels in the existing generation mix. For simplicity, we assume that such conditions are rare.

All CT units are assumed to have the same marginal operating and capital costs (in real terms) in all years of the simulations, so technological progress and fuel price changes are not represented. The annualized capital and fixed operations cost is assumed to be \$61 000/installed MW/yr in annualized real dollars. With an assumed forced outage rate of 7%, this translates into a cost of \$65 600/unforced MW/yr for a new turbine, again in real dollar terms. We assume that the CT's marginal operating cost is \$79/MWh. We also assume that the lead time for CT construction is four years, including time required for necessary regulatory approvals. The willingness of investors to build new turbine capacity is assumed to depend on future profit forecasts, which in turn are assumed to depend on profits that would have been earned by such a CT in previous years, equal to the sum of capacity and E/AS gross margins, minus the annualized cost of CT capacity. Profits in previous years are important to consider because they provide a basis for forecasting the level and volatility of profits in the future.

The E/AS gross margin that a turbine would earn in each year is critical to its profitability and therefore to investors' willingness to build capacity. Furthermore, this gross margin varies greatly over time, depending strongly on the amount of capacity relative to the actual peak loads. The model therefore includes a relationship between market conditions (represented by the actual reserve margin) in a year and the E/AS gross margin earned by a new turbine. Thus, gross margin GM_y is a function $GM_y(r_{A,y})$ of actual reserve. This gross margin consists of two portions: a scarcity portion, which arises when price exceeds the marginal cost of the last generating unit (due either to a genuine shortage or to exercise of market power), plus an assumed \$10 000/MW/yr that is earned in ancillary service markets that are not modeled or that results from margins earned

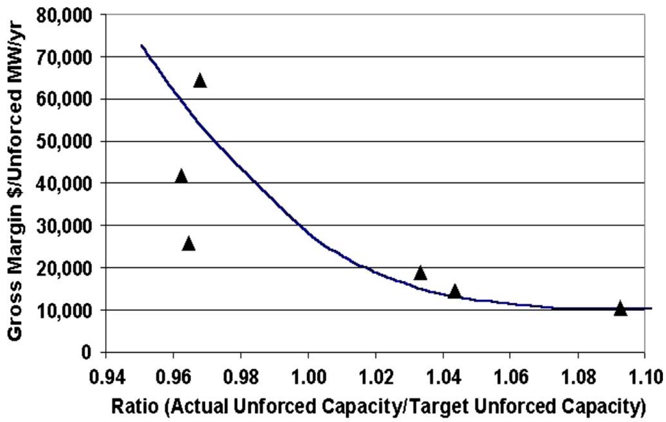

Fig. 8. Relationship of E/AS gross margin to unforced reserve, expressed as a ratio with respect to the target installed capacity for PJM.

when more expensive plants are on the margin. [5] Fig. 8 shows the resulting total E/AS gross margin for a hypothetical new turbine (solid line), as well as the actual values that would have been experienced for such a turbine in years 1999–2004 (triangles), under the assumption that the turbine could operate in any hour in which price exceeded its marginal running cost (from PJM's State of Market Report [23, Table 2–34]). The actual values confirm the reasonableness of the E/AS function used. The figure shows that when the actual reserve margin equals the target installed reserve margin (IRM) (indicated by a ratio of 1 on the x-axis), the E/AS gross margin is about $28 000/unforced MW/yr. This is well below the annual fixed cost of a CT, justifying a capacity payment system.

Investment Behavioral Characteristics: As Fig. 2 shows, four sets of behavioral characteristics are modeled: two are used to calculated risk-adjusted forecast profit (forecasting and risk-aversion assumptions); another set is used to determine the maximum amount of new entry; and a fourth set concerns the bid prices that suppliers provide to the capacity market. These assumptions are discussed further below.

Calculation of the Amount of New Capacity Bid Into Auction: The procedure is summarized as follows. Let Y be a particular year. The addition of CT capacity in year Y generally depends not only on the price $P_{ICAP,Y}$ in the auction held in year $Y-4$ but also on the anticipated E/AS gross margin in Y, as well as profits $\pi_y = P_{ICAP,y} + GM_y(r_{A,y}) - FC$ in years y previous to Y. FC is the annualized fixed cost of constructing a CT, in real annualized terms. (Note that all terms are expressed in compatible units of [$/unforced MW of capacity/year].) Profits in previous years provide the basis for forecasting the level and volatility of profits in the future, which in turn determine the amount of new capacity NCA_Y that investors are willing to bid into the auction.

[5]Within the model, this function could be calculated by a production costing submodel that represents all operating constraints. Instead, we obtain this function from a simple probabilistic production costing model for PJM in which the energy price is assumed to equal the marginal cost of generation unless load is within 8.5% of available capacity. At that point, scarcity pricing is assumed to take place and the price of energy hits the cap ($1000/MWh). The simplified model has a capacity mix of baseload coal and gas-fired combined cycle and combustion turbine capacity and a load distribution reflecting the combined PJM-Eastern and PJM-Western load shape. Subtracting the assumed marginal running cost of the CT yields the estimated scarcity rent. The scarcity rent is then added to an assumed minimum E/AS gross margin of $10 000/unforced MW/yr. Although the particular assumptions of the model are somewhat uncertain, Fig. 3 shows that the resulting E/AS gross margin is a reasonable approximation to actual PJM conditions. A function $GM_y(r_{A,y}) = \mathrm{EXP}(a_0 + a_1 r_{A,y} + a_2 r_{A,y}^2 + a_3 r_{A,y}^3)$ closely fits the output of the production costing model.

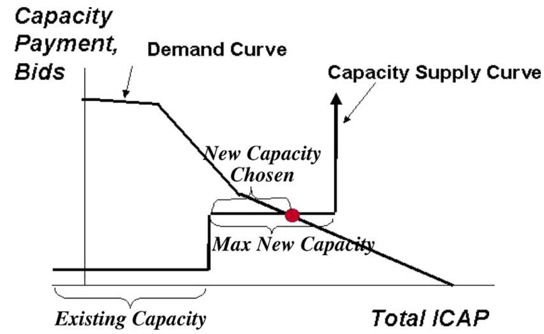

Fig. 9. Determination of price for capacity installed in year y.

This capacity is used to construct a capacity bid curve for an auction held in year $Y-4$ for capacity to be installed in year Y. The curve has the general shape shown in Fig. 9. The model creates such a curve in each year. Existing capacity is assumed to be bid in at a low price, while the maximum potential incremental capacity NCA_Y is bid in an assumed bid that might be higher. The capacity price is then calculated as the intersection of that capacity bid curve with the demand curve.

The following are the specific steps involved in construction of a capacity bid curve in each year.

1) The anticipated or actual profit π_y for a new CT for each of several years $y = Y, Y-1, Y-2, \ldots, Y-7$ is calculated (see top of Fig. 2). "Profit" is defined in the sense meant by economists: as profit over and above the cost of capital; so a zero profit signifies that capital costs are just being covered. Profits in years $Y-4$, $Y-5$, $Y-6$, and $Y-7$ are assumed to be known exactly, since capacity and E/AS prices in those years have been observed or can be accurately estimated by the time the auction in $Y-4$ takes place. Profits in years $Y-1$, $Y-2$, and $Y-3$ can be estimated based on the known $P_{ICAP,y}$ and a projection of gross margin based on the forecast reserve margin $GM_y \cong GM_y(r_{F,y})$. Profit in year Y is more difficult to forecast, because $r_{F,Y}$ is not yet known (since the auction has not yet taken place). So an estimate is obtained by assuming that enough capacity would be added in Y so that the forecast reserve margin in that year would be the same as in the previous year $r_{F,Y-1}$. The demand curve in Y (used in the auction held in $Y-4$) is then used to estimate $P_{ICAP,Y}$ for that year based on that guess of the forecasted reserve, and GM_Y is projected using the same guess.
2) The value of the utility function $U(\pi_y)$ of the anticipated or actual profit π_y for each $y = Y, Y-1, Y-2, \ldots, Y-7$ is then calculated. $U(\pi_y)$ is a concave nonlinear utility function that represents attitudes toward risk. The simplest possible risk-averse utility function is the negative exponential form $U(\pi_y) = a - be^{-c\pi y}$, which is standard in decision analysis [6]; the risk attitude can be summarized in one risk-aversion parameter c. The constants a,

b, and c are calibrated so that zero utility results if profit is zero; a utility of 1 results if $\pi_y = FC$ (i.e., a gross margin, including capacity payments, equal to double the fixed cost); and $\pi_y = 0.5FC$ results in a utility of 0.7 (indicating a somewhat but not extreme risk aversion). Other degrees of risk aversion are readily simulated. For instance, $U(0.5FC) = 0.5$ defines a linear or risk-neutral utility function (the investor cares only about average profits and not their volatility).

3) A risk-adjusted forecast profit $RAFP_Y$ for capacity added in year Y is calculated. $RAFP$ is defined as a certain profit that is viewed by investors as being just as desirable as the actual stream of observed and estimated profits (see the eight profits shown at the top of Fig. 2). The more risk-averse investors are, the more that profit fluctuations will lower $RAFP$. $RAFP$ is calculated by first obtaining a weighted utility of the observed and estimated profits

$$WU_Y = \Sigma_{y=Y,Y-1,\ldots,Y-7} W_{Y-y} U(\pi_y) \tag{6}$$

where W_{Y-y} is a weight assigned to profits that occur $Y - y$ years before the online date for new capacity in that auction. The weights sum to 1. The weights reflect the degree to which the history of profits is relevant to forecasting profit; the greater the weight placed on previous years' profits ($y-1$, $y-2$, etc.), the less relative weight is placed on the capacity price in the particular year y's auction. A simple form of such weights is the lagged formulation $W_{y-1} = \alpha\, W_y$, with $\alpha < 1$; $\alpha = 0.8$ is used in the simulations here. From the weighted utility, $RAFP_Y$ is calculated by inverting the utility function $WU_Y = U(RAFP_Y)$

$$RAFP_Y = -\ln\left((a - WU_Y)/b\right)/c. \tag{7}$$

4) The maximum capacity addition NCA_Y based on $RAFP_Y$ is obtained using a function with the following properties.
   a) If $RAFP_Y$ is zero (equivalent to revenues just covering costs, including return on capital), then the amount of capacity added is 1.7% of the existing capacity (so that if profit in every year is zero, then capacity grows just fast enough to meet the 1.7% mean PJM load growth).
   b) If $RAFP_Y = FC$ (that is, revenues are sufficient to cover two times the fixed cost), then the amount of entry equals $\beta > 1.7\%$ of existing capacity. The assumed $\beta = 7\%$ value is based broadly on recent experience in PJM. In particular, the maximum annual capacity additions in the PJM-Eastern Region since 2000 amounted to 3800 MW, equaling 6.3% of the 60 015 MW of capacity existing at that time.
   c) Capacity additions at other $RAFP$ levels are an increasing function of $RAFP$ and follow a curve that is the same shape as the assumed utility function (see the upward sloped portion of Fig. 2), with two exceptions. First, additions cannot be negative; retirements are not considered. Second, additions cannot exceed β so that implausibly high levels of investment cannot occur in a single year. As a result, the $RAFP$ function has the S-shape shown in Fig. 2.

   These assumptions yield the following relationship between the maximum additions in year Y and the utility of $RAFP$:

$$NCA_Y = X_{Y-1} * \mathrm{MIN}\left[\beta, \mathrm{MAX}\left(0, 0.017 + \lambda(WU_Y - U(0)\right)\right] \tag{8}$$

   where: $\lambda = (\beta - 0.017)/(U(FC) - U(0))$, and X_{Y-1} is the installed capacity in the previous year.

Given the existing capacity X_{Y-1} and its bid B_E, and the maximum increment in capacity NCA_Y and the assumed bid B_N associated with it, the resulting ICAP price and quantity for year Y can then be calculated, as shown in Fig. 9.

Bid Prices for Capacity: The third set of behavioral characteristics in the model involves the prices at which capacity is bid into the auction. For simplicity, no retirements of existing capacity are considered. For the base case, we assume that all capacity is bid in at \$0/MW/yr. That is, generators commit to maintaining or building certain quantities of capacity and then bid in a vertical supply curve, making them price takers for the price of capacity. Alternative assumptions are considered in our sensitivity analyses. Fig. 9 shows how the resulting market clearing price and quantity of capacity are calculated. The new capacity that is offered but not accepted is not built.

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