A Critique of Designing Resource Adequacy Markets to Meet Loss of Load Probability Criterion

Yong T. Yoon* and Frank A. Felder**

Abstract - To ensure resource adequacy in restructured electricity markets, policymakers have adopted installed capacity (ICAP) markets in some regions of the United States. These markets ensure that adequate generation exists to satisfy regional Loss of Load Probability(LOLP) criterion. Since the incentives created through ICAP mechanisms directly impact new generation and transmission investment decisions we examine one important factor that links ICAP markets with LOLP calculations;, determining the amount of ICAP credit assigned to particular generation units. First, we review and critique the literature on electric power systems' market failure resulting from demand exceeding supply. We then summarize the method of computing (the LOLP) as a means of assessing reliability and relate this method to ICAP markets. We find that only the expected value of available generation is used in current ICAP markets while ignoring the second and higher order moments, which tends to mis-state the ICAP value of a specific resource. We then consider a proposal whose purpose is to avoid this ICAP assignment issue by switching from ICAP obligations to options. We find that such a proposal may fail to not provide the benefits claimed and suffers from several practical difficulties. Finally, we conclude with some policy recommendations and areas for future research.

Keywords: power system reliability, Loss of Load Probability (LOLP), market mechanisms, electric power industry restructuring, installed capacity

1. Introduction

With the introduction of competition in the electric power industry, a new environment is created where wholesale electricity is supplied and consumed through an evolving market process in which market prices, rather than regulatory policy, determine investment and consumption decisions.

Substantial disagreement has occurred regarding whether markets alone will produce adequate generation to satisfy Loss of Load Probability (LOLP) criterion [1-4]. Due to the crisis in the California electricity markets over the last several years and the recognition of insufficient demand response, U.S. federal policymakers have recently proposed resource adequacy requirements [5].

This paper summarizes the debate regarding the need for resource adequacy requirements in restructured electricity markets and critiques a recent contribution to that debate. It then reviews the LOLP calculations that are the rationale behind resource adequacy requirements and summarizes at a conceptual level an existing market mechanism, installed capacity (ICAP) markets, used in the northeastern region of the U.S. to ensure resource adequacy.

* School of Electrical and Computer Engineering, University of Oklahoma, Norman, OK 73019, USA (ytyoon@ou.edu)

** School of Business, Manhattan College, Riverdale, NY 10471, USA (frank.felder@manhattan.edu)

Received December 7, 2002 ; Accepted February 21, 2003.

Since the linkages between the ICAP market mechanism and the LOLP modeling are critical for ensure that sufficient resource adequacy exists, this paper then examines in detail one critical linkage;, the assignment of ICAP credit to specific generators. The current practice uses the expected or mean availability of a generation unit rather than higher moments, in determining a unit's ICAP contribution. Then, this paper analyzes a recent proposal to institute installed capacity contract options instead of contract obligations, which is motivated in part to avoid this assignment problem [6]. We conclude with some policy recommendations and areas for future research.

2. The Economics and Reality of Resource Adequacy in Restructured Electricity Markets

2.1 Why Restructured Electricity Markets Fail to Consistently Match Supply and Demand in Theory and Practice

Typically, when the available generation capacity far exceeds load demand, the competitive wholesale energy price reflects the production cost for meeting the marginal demand. This concept is well explained by the economics theory of competitive market behavior. The production cost for meeting the marginal demand is simply the short run marginal cost of supply [7-8]. When load demand gets close to the available generation capacity, however, the wholesale energy price seemingly fluctuates with no relations to the production cost for meeting the marginal demand. This discrepancy occurs because the wholesale energy price reflects the cost of fail to supplying the marginal demand rather than the production cost when the load demand is close to available generation capacity. The cost associated with not supplying less than the marginal demand is much higher than the short run marginal cost of supply [9].

Hypothetically, in perfect markets with no transaction costs, supply and demand instantly equilibrate, and the result is that no shortage of supply ever occurs because prices rise to levels that reduce demand to equal available supply. Even in theory, however, restructured electricity markets fail to meet the conditions of perfectly clearing markets due to flaws on the demand side [1-3]. This contradicts the conclusion that economic theory shows that the spot market itself is sufficient to provide adequate investment signals that will result in the socially optimal level of investment [6].

Little to no demand elasticity exists because many consumers in restructured markets, due to retail rate design, fail to, let alone pay the spot price for electricity, thereby eliminating their ability and incentive to respond to changing prices. Consequently, to the system operator, consumers' demand curve is vertical. Second, in restructured electricity markets, consumers that have procured sufficient supplies to meet their demand cannot be disconnected from the system in real time, which prevents the physical enforcement of bilateral contracts and result in underinvestment [3]. Although theoretical models make no such explicit assumption, such market models assume that buyers cannot consume the desired product only if they pay for it. Third, in restructured electricity markets, the wholesale market clearing mechanism is a computer program. When demand literally exceeds supply, these programs make no price increase to equilibrate supply and demand. Instead, the system operator takes the necessary steps to reduce demand, for example through voltage reductions and rolling blackouts, in order to preserve the system.

Some practical issues associated with electricity make it difficult for electricity markets to consistently match supply and demand, although many other markets experience shortages that are resolved not through price signals but by delivery lags in shipping goods [10]. Given the physical requirement to match supply and demand most instantaneously in order to prevent a system blackout, no delivery lags can be used in electricity markets. Further complicating the picture, generator units and transmission lines are subject to random outages.

Due to random outages generation capacity must be larger than the load demand at all times. As the load demand grows over time, at some point the existing generation capacity must be expanded to remain slightly larger than the demand growth. When the load demand gets close to the available generation capacity, the cost of supplying less than the marginal load is the cost of supplementing additional generation capacities, i.e., the wholesale energy price reflects the cost of supplementing additional generation units when load demand gets close to the available generation capacity.

Vázquez et al. has also suggested other reasons why restructured electricity markets inconsistently equilibrate [6]. Vázquez et al. also identify several practical difficulties that prevent realization of the socially optimal level of investment. They correctly point out that the application of price caps, consumers isolation from spot prices, and the lack of consumer maturity are some practical difficulties confronting electricity markets. Some of their other reasons they point to, however, make no economic sense. One is their statement that potential investors in new generation electricity markets are risk averse. Whether or not this statement is accurate, risk aversion would result in potential investors demanding a higher expected price of electricity than risk-neutrality, but not in a lower level of investment in equilibrium. Another difficulty postulated by the authors is oligopolistic behavior of incumbent utilities, which underinvest to raise market prices, when the barriers to entry are sufficient to block the contestability effect of potential new entrants. Again, under this hypothesis, prices should rise to levels sufficient to induce adequate investment to overcome any barriers to entry.[1]

Due to these theoretical and practical limitations, policy intervention is required, and one such policy is the establishment of ICAP markets.

2.2 The Theory Behind Installed Capacity Markets and Its Shortcomings

The economic justification for ICAP markets is due to the theoretical and practical difficulties of ensuring that electricity markets always have adequate supply available in real time to meet demand. Failure threatens the power system's reliability (a negative externality), and a mechanism is needed to ensure that adequate supply is available for a given LOLP criterion. Once this adequate supply requirement is imposed on the market, then market mecha-

[1] Vázquez et al. [6] also assert that consumers eventually would realize that they need to protect themselves against high prices and blackouts. But since reliability is a public good due to the demand flaws mentioned above, a consumer cannot such a contract only if unless all other consumers do the same. This, of course, raises free-rider problems, which the authors properly identify later in their paper.

nisms, such as ICAP, can be used to meet that requirement at the least cost [1].

ICAP mechanisms have three key concepts, First, a desired level of reliability is determined in terms of the required LOLP. The LOLP is the probability of the load demand (and the excess capacity for dealing with outages) exceeding the available generation capacity. Thus, the LOLP measure the adequacy of the long-term electricity supply. Second, the owners of existing and/or planned generation units are assigned with an appropriate amount of ICAP credits depending on the characteristic of their respective units. Third the Load Serving Entities (LSEs) who have the contractual obligation to meet load demand are required to obtain a certain amount of ICAP credits based on the characteristics of their respective load demand. By design, the desired level of reliability is achieved by ensuring adequate supply of resources to meet the load demand when all the LSEs fulfill their ICAP requirements [11].

Nevertheless, the ICAP mechanisms currently being implemented in some regional electricity markets in the U.S. may function less effectively than desired for several reasons. One reason is the shortcomings of the existing resource adequacy LOLP framework, which are discussed elsewhere [12-13]. Another is related to the inability of existing ICAP markets to reward incremental transmission investment for its contribution to resource adequacy. Only ICAP credit is awarded to generation units even though incremental transmission facilities may aid in satisfying resource adequacy criterion. The issue we address is the "loose" relationship between the required LOLP and the ICAP credit/requirement assignment. This relationship is part of the motivation for a proposal, discussed later, to transfer ICAP obligations into options.

3. Computation of Loss of Load Probability Measure

The LOLP measure is a remnant of the operating and planning practices of vertically integrated utilities, i.e., entities that owns and operates the generation and transmission assets within a regional electric power system while assuming the obligation to serve the native customers in the same system for a guaranteed rate of return on their investment allowed by regulators. The regulators, in turn, impose a set of strict (technical) standards on the utilities regarding how they should serve their native customers. Among them, a reliability standard based on the LOLP measure ensures adequate resources to meet the long-term load demand. In this sense, by comparing the peak load demand to the available generation capacity subject to possible equipment outages, the LOLP computes the probability that the load demand of a vertically integrated utility's native customers exceeds the supply owned by the utility. Mathematically, the LOLP, p_{LOLP}, is computed by solving

$$p_{LOLP} = \text{Prob}\{q_D - q_G > 0\} \tag{1}$$

where q_D and q_G are the peak load demand and the available generation capacity, respectively [14].

For example, suppose that there is a regional electric power system where the peak load demand and the available generation capacity subject to outages can be represented by Normal distribution. Then, the LOLP of this system is given as a lightly shaded region in Fig. 1.

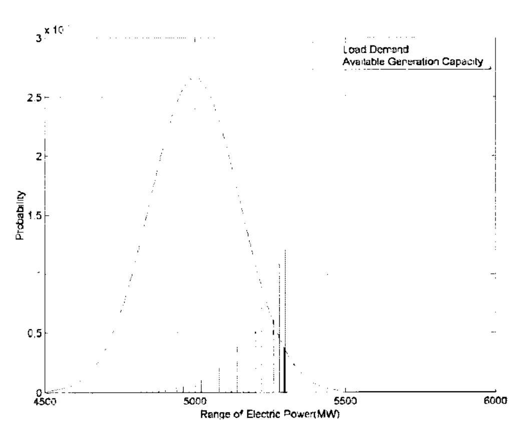


Fig. 1 Graphical Illustration of the LOLP computation When Represented Using Normal Distribution

4. Installed Capacity Markets

In some regional markets of U.S. ICAP markets are introduced to provide the financial incentives necessary for maintaining or exceeding required LOLP. Important details of the actual implementation of ICAP mechanisms differs from one market to another, reflecting regional characteristics and practices. Nevertheless, the nucleus of the mechanisms is shared in all of these markets and is described here for a conceptual examination.

Fig. 2 shows the flow chart of ICAP mechanisms as currently being implemented.

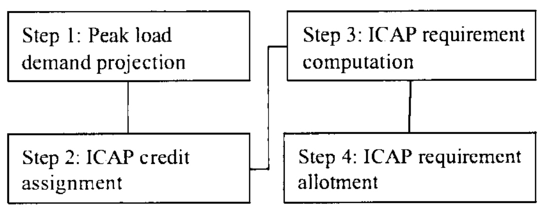


Fig. 2 Flow Chart of ICAP Mechanisms as Currently Being Implemented in Some Regional US Electricity Markets

In Step 1 the Independent System Operator (ISO), a nonprofit organization with full operational authority created as a result of restructuring to ensure short term reliability, chooses a suitable representation for projecting the peak load demand, As described in Section 3, the peak load demand can be represented with some probabilistic distribution. In Step 2, the ISO assigns ICAP credits to owners of existing and/or planned generation units according to some pre-agreed-upon valuation. Typically, a pre-agreed-upon valuation consists of maximum generation seasonal capacity (or of the maximum generation seasonal capacity weighted by the availability of a generator) which is calculated as a rolling average over months. For example, the owner of a 100MW generating unit with 90% availability may be assigned either 100MW of ICAP credits or 90MW of ICAP credits depending on the actual implementation of the ICAP mechanisms. In Step 3, the ISO determines the amount of ICAP credits necessary for satisfying the required LOLP.

Recently, the ISOs in the northeastern U.S. have switched or are in the process of switching from granting ICAP credit to a generator based on its seasonal rating to adjusting that seasonal rating based on the generation unit's availability. This switch is designed to reward generator operators of who maintain high unit availability by granting them more ICAP credit than operators of identical but less available units. Empirical evidence, both before and after restructuring, demonstrates that generation unit availability does improve during peak periods, suggesting that incentives to improve availability may actually do so [15-16].

In Step 4 the ISO divides the necessary ICAP credits determined in Step 3 and assigns an ICAP requirement to each load according to the ratio of its coincidental demand to the system peak load demand. Finally, each load satisfies its ICAP requirement by purchasing sufficient ICAP credits from owners of existing generation units or by self-supplying. By design, this step ensures meeting the required LOLP thus achieving the desired level of reliability without depending on a single entity with the obligation to serve. Rather than a single entity assuming the obligation to serve, new entities, which are derived from the utility following functional unbundling process are driven by financial incentives.

One key to ICAP mechanisms currently being implemented is the ISO's ability to compute the amount of ICAP credits necessary to satisfy the required LOLP (Step 3). If the ISO under-estimates the amount of ICAP credits, then the required LOLP is unsatisfied and fails to meet the desired level of reliability. On the other hand, if the ISO calculates the amount to be too high, then the system-wide efficiency is reduced due to forcing over-investment to meet the load demand. Unfortunately, accurate computation in Step 3 is quite involved.

As before, suppose that the peak load demand is represented with Normal distribution of some mean and variance, Q_D and σ_D, respectively. Further suppose that N existing and planned generation units exist where each unit g_i is characterized by its maximum capacity, $Q_{g_i}^{\max}$ and rate of its availability, A_{g_i} where $0.00 \le A_{g_i} \le 1.00$. Instead of directly solving the amount of ICAP credits necessary for satisfying the required LOLP, we first solve a slightly different problem.

Denote a subset of generators with S_k and the size of this subset with n_k, i.e., $|S_k| = n_k$ and $n_k \le N$. Let $\bar{q}_k$ and $\bar{a}_k$ be vectors of size $(n_k \times 1)$ whose elements are Q_{g_i} and A_{g_i}, respectively, where $g_i \in S_k$. In addition, let $u_{(2^m-1)}$ be a vector of size $(n_k \times 1)$ whose elements are the binary representation of $(2^m - 1)$, where $m \le n_k$.

Using the newly introduced notations then we can construct the vectors of available generation subject to outages, $\bar{Q}_{S_k}$, and of the associated probability, $\bar{A}_{S_k}$, whose sizes are both $(2^n \times 1)$ and whose m th element is given by $\mu'_{(2^m-1)} \cdot \bar{q}_k$ and

$$\prod_{\substack{i, \\ u_{(2^m-1)(i)\neq 0}}} \bar{a}_k(i)$$

$\bar{f}(i)$ is the i th element of the vector $\bar{f}$, respectively. The vectors of available generation subject to outages, $\bar{Q}_{S_k}$, and of the associated probability, $\bar{A}_{S_k}$, are reduced to $\hat{Q}_{S_k}$ and $\hat{A}_{S_k}$ by sorting the elements in $\bar{Q}_{S_k}$ in ascending order and deleting elements whose value appear more than once while adding up the associated probabilities in $\bar{A}_{S_k}$ for the corresponding deleted elements in $\bar{Q}_{S_k}$. The result is the vector $\hat{Q}_{S_k}$ and $\hat{A}_{S_k}$ whose elements are all possible generation capacities by permutation of generation units in S_k and their corresponding probabilities.

For the given peak load demand, the LOLP associated with S_k can be, then, computed by solving

$$\sum_{\substack{m, \\ 1\le m<\left|\hat{Q}_{S_k}\right|}} \left(\sum_{i=1}^{m} \hat{A}_{S_k}\right) \cdot \int_{q_D=\hat{Q}_{S_k}(m)}^{\hat{Q}_{S_k}(m+1)} \frac{1}{\sqrt{2\pi}\sigma_D} \exp\left[\frac{(q_D-\mu_D)^2}{2\sigma_D^2}\right] dq_D + \left(\sum_{i=1}^{\left|\hat{Q}_{S_k}\right|} \hat{A}_{S_k}\right) \cdot \int_{q_G=\hat{Q}_{S_k}\left(\left|\hat{Q}_{S_k}\right|\right)}^{\infty} \frac{1}{\sqrt{2\pi}\sigma_D} \exp\left[\frac{(q_D-\mu_D)^2}{2\sigma_D^2}\right] dq_D \quad (4)$$

It is noted that Eq. (4) is equivalent to Eq. (3) where a different probabilistic representation is used for describe the available generation capacity. In fact, as $\hat{Q}_{S_k} \to \infty$ Eq. (4) approaches Eq. (3) due to Law of Large Numbers [17].

By solving Eq. (4) for all subsets of generators, the LOLP can be computed associated with every possible combination of existing and planned generators. Denote a subset of generators and its LOLP with $(S_k, LOLP_k)$ pair. There are 2^N such pairs for the given electric power system. The required LOLP is then used for dividing the pairs into two groups. One group, G_1, consists of subsets of generators satisfying the required LOLP, and the other group, G_0, consists of the remaining subsets of generators.

Now we can solve for the amount of ICAP credits necessary to satisfy the required LOLP. Suppose the ISO assigns the amount of ICAP credits to generation unit owners according to their maximum generation capacity. Then, the necessary amount of ICAP credits is determined by computing the sum of maximum capacity for each subset of generators and taking the minimum of the capacity sum in G_1 which is greater than the maximum of the capacity sum in G_0. This calculation achieves the desired effect of ensuring the reliability of meeting the required LOLP. Similarly suppose the ISO assigns ICAP credits to generation unit owners according to the maximum generation capacity weighed by generation availability. Then, the necessary amount of ICAP credits is determined by computing the sum of the weighed maximum capacity for each subset of generators and taking the minimum of the weighed capacity sum in G_1 which is greater than the maximum of the weighed capacity sum in G_0. Again, this calculation achieves the desired effect of ensuring the reliability for meeting the required LOLP.

While ensuring the desired level of reliability, the approach described has two problems. First, this approach may be overly conservative. Suppose there are two subsets, $S_{k'}$ and $S_{k''}$ whose means and variances given by $\mu_{S_{k'}} < \mu_{S_{k''}}$ but $\mathrm{var}_{S_{k'}} < \mathrm{var}_{S_{k''}}$. Both the sum of maximum capacity and the sum of weighted maximum capacity is less for $S_{k'}$ than for $S_{k''}$. However, $(S_{k'}, LOLP_{k'}) \in G_1$ but $(S_{k''}, LOLP_{k''}) \in G_0$, is possible, since $LOLP_{k'} < LOLP_{k''}$. May occur. In both Eqs. (3) and (4) the higher variance leads to the higher LOLP. Based on the method used by the ISO to determine the necessary ICAP credits to ensure the desired level of reliability even when $LOLP_{k'}$ is less than the required LOLP, the loads cannot purchase the ICAP credits as given in $S_{k'}$ only, to meet their ICAP requirement. This is because by design the amount of necessary ICAP credits is set much higher due to the total ICAP credits assigned to $S_{k''}$.

Second, this approach assumes that a subset of generators, S_k, can be readily identified. However, when constructing S_k the ISO must consider not only existing generation units but also planned generation units. A significant uncertainty is associated with projecting the rate of availability and the maximum capacity of a generation unit yet to be built [18]. Plus, even if these quantities may be accurately projected, uncertainty is associated with the time before a planned unit becomes operational. This uncertainty has a direct effect on constructing subsets of generators because some subsets that need to be considered may be irrelevant if some of the planned generators are not operational over the period considered in the ISO's analysis.

Both of these problems associated with the ICAP mechanisms currently being implemented arise because the total ICAP credits assigned to a few subsets in G_1 can be less than the total ICAP credits assigned to some subsets in G_0.

A new method of assigning ICAP credits to owners of existing and planned generation units must be developed so that these problems can be eliminated by assuring the total ICAP credits associated with any subsets in G_1 are always greater than those associated with every subsets in G_0.

An illustrative example of this process of calculation is provided in [19].

5. ICAP Obligations Versus ICAP Options

Vázquez et al. [6], propose a reliability option contract that they claim would ensure adequate generation with a limited amount of regulatory intervention, avoid requiring the regulator to calculate the firm capacity of each generation unit, provide maximum price insurance for consumers, and would improve the incentives of generation owners to have their units available during critical periods.[2] This later problem is at the crux of the issues addressed in the previous section, i. e., how to determine the ICAP value of a particular generation unit in a way that provides incentives for efficient improvements in unit availability.

The crux of Vázquez et al.'s proposal is to establish an organized market where the regulator, presumably the ISO,

[2] The referred to paper suffers by virtue of its many overgeneralizations and unsubstantiated statements. Some are tangential to the paper's major points whereas others are directly relevant. For example, generators in the Northeast that sell capacity to a specific region, e.g., New York, cannot — as the authors assert — decide to export instead of selling into the pool when demand is being rationed. Moreover, despite that the authors state otherwise, generators are under obligations to consumers when they sell capacity. These and other examples detract, unfortu-

requires the market or the system operator to buy a prescribed volume of reliability contracts from generators on behalf of load. These reliability contracts are auctioned and consist of a combination of a financial call option with a high strike price and an explicit penalty for nondelivery.

The benefits of Vázquez et al.'s proposal are due not to the option element, but to directly linking financial performance with generation availability. Under Vázquez *et a.l*'s proposal, if a generator obligated under the proposed contract fails to provide energy when called upon, it would have to pay a penalty whereas no such penalty exist in current ICAP markets. Thus, this proposal directly links performance when the market is short of capacity. Of course, picking an efficient penalty for a given unit is extremely difficult while also avoiding expending too little or too much on maintenance for improved reliability for its type.

As noted above, existing capacity markets only indirectly make this linkage through performance audits and adjustment to the amount of capacity a generation unit can sell by its historic availability. Generation owners also have an incentive to make their units available during high-priced periods, which are times in which capacity is likely needed to avoid reliability problems.

Regarding the option element, the difference between Vázquez *et al*'s proposal and existing capacity markets in the Northeast region of the United States is not as substantial as their paper may imply. The authors' proposal could be changed from an option to a firm contract by setting the strike price to the marginal cost of the generation unit that sold the firm contract and requiring generators, when called upon, to pay the market price plus the penalty suggested by the authors. The authors' option proposal sets a definite price cap to the market price of energy (MWh), whereas the firm contract proposal has a floating price cap based on the marginal cost of the most expensive operating unit.

Vázquez et al. emphasize that under their proposal the final volume of capacity assigned to each generator is a market result rather than the outcome of an administrative process (in contrast to most current methods). In the Northeast capacity markets, the generation owners determine the amount of capacity they want to sell, subject to anti-withholding provisions and the capability of their units. Whether an investor could sell capacity options on speculation, i.e., without actually having a physical unit under its ownership when selling the capacity option, is unclear from the authors' proposal. Permitting such speculation is unlikely to give system operators enough comfort; grestricting such speculation results in some form of administrative limits on the sale of capacity options.

Some important technical issues need to be developed further before the authors' proposal could be implemented. Many of the authors' specific recommendations are made without justification. For instance, they suggest that the strike price should be at least 25% above the variable cost of the most expensive generator expected to produce during the considered time horizon. Why is 25% the minimum increase? Should this value be independent of fuel price volatility? The paper recommends, without justification, a lag period of two years; it suggests indexing the premium fee with inflation or "some other parameter" and it proposes safeguard rules with no explanation of exactly why they are needed, which abnormal market behavior they are design to prevent, or what the basis is for such rules. The authors acknowledge that the need for these safeguard rules is not obvious and depends on some undefined characteristics of the system. These are just some of the important details that require further discussion and research.

In addition, Formula (1) in [6] could be adjusted to include inflation, the time value of money, and the specific discount rate of the particular generator that is calculating its premium bid. The authors' methodology fails to account for planned maintenance or for profits generators make from energy sales, which can be used to pay going-forward costs.

nately, from the paper's contributions.

6. Policy Implications and Areas for Future Research

With the introduction of competition, reliability is no longer ensured by having a single entity with the obligation to serve but rather must be ensured through market-driven incentives. In this line of thinking, the ICAP mechanisms currently being implemented in some regional markets in the U.S. are a step in the right direction. This paper discusses how the method of assigning ICAP credits to owners of existing and planned generation units needs to be modified. In addition, policy proposals for switching from ICAP obligations to options appear to overlook this problem and raise some important practical issues that have been addressed to date.

While the problems associated with the current implementation of the ICAP mechanisms are pointed out here, this paper proposes no possible methods for remedying the insufficiencies but leaves this matter for future research.

References

[1] A. Jaffe and F. A. Felder, "Should Electricity Markets Have A Capacity Requirement: If So, How Should It Be Priced?" *The Electricity Journal*, Dec. 1996, pp. 52-

60.

[2] P. Joskow, "Electricity Sectors in Transition," *The Energy Journal*, Vol. 19, No. 2, 1988, pp. 25-55.

[3] S. Stoft, Power System Economics: Designing Markets for Electricity, New Jersey: *IEEE Press*, 2002, p. 15.

[4] R. L. Borlick, "Competitive Electricity Markets Can Provide Optimum Power Supply Reliability," *IBC Conference on Reliability for Competitive Power*, September 29, 1997.

[5] U.S. Federal Energy Regulatory Commission, Standard Market Design Notice of Proposed Rulemaking, Docket No. RM01-12-000, July 31, 2002, pp. 259-290.

[6] C. Vázquez, M. Rivier, and I. J. Pérez-Arriaga, *IEEE Trans. Power Syst.*, vol. 17, May 2002, pp. 349-357.

[7] H. Varian, *Microeconomic Analysis, 2nd ed.*, New York: Norton & Company, Inc., 1984.

[8] F. C. Schweppe, M. C. Caramanis, R. D. Tabors, and R. E. Bohn, *Spot Pricing of Electricity*, Massachusetts: Kluwer Academic Publishers, 1987.

[9] Y. T. Yoon, "A Possible Notion of Short -term Value-based Reliability," *Proc. 2002 IEEE Power Engineering Society Winter Meeting*, pp. 315-320.

[10] D. W. Carlton, "Equilibrium Fluctuations When Price and Delivery Lag Clear the Market," *Bell Journal of Economics*, Vol. 14, No. 2, 1983, pp. 562-572.

[11] New York Independent System Operator, "NYISO Installed Capacity Manual", Schenectady, NY, December 2002. http://www.nyiso.com/services/documents/manuals/pdf/planning_manuals/icap_manual_12_30_02.pd

[12] F. A. Felder, "An Island of Technicality in a Sea of Discretion": A Critique of Existing Electric Power Systems Reliability Analysis and Policy," *The Electricity Journal*, April 2001, pp. 21-31.

[13] F. A. Felder, "Probabilistic Risk Analysis of Restructured Electric Power Systems: Implications for Reliability Analysis and Policies" PhD. Dissertation, Department of Technology, Management and Policy, M.I.T., Cambridge, MA, 2001.

[14] R. Billinton, Reliability, Assessment of Electric Power Systems Using Monte Carlo Methods, New York: Plenum Press, 1994.

[15] North American Electric Reliability Council, "Generating Availability Trends Summary Report: Studies 1 to 5," May 5, 1989.

[16] H. M. Merrill, G. Lawrence, and S. Lawrence, "Understanding New England Generating Unit Availability," prepared by Merrill Energy LLC, Diamond Ridge, Inc., and Babcock & Wilcox, Inc. for the ISO New England Inc., Holyoke, MA, USA, June 14, 2001.

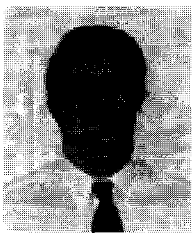
[17] A. W. Drake, *Fundamentals of Applied Probability Theory*, New York: McGraw-Hill, 1967.

[18] ISO-NE, "Report on Studies Evaluating Reliability Impacts of Deactivation of Devon Units 7, 8, and 10," July 9, 2002.

[19] Y. T. Yoon and F. A. Felder, "Study of Loss of Load Probability in Designing Installed Capacity Market," *Proc. 2002 IEEE Power Engineering Society Summer Meeting*, Chicago, IL., July 21-25, 2002.

Yong T. Yoon

He received Ph.D. degree in Electric Engineering and Computer Science from MIT in 2001. He has been with the School of Electrical and Computer Engineering at the University of Oklahoma as an assistant professor since January 2002 and is engaged in a research in large-scale system dynamics and control, electric power network economics, transmission provision and pricing, and regulation, privatization, and competition in network utilities.



Frank A. Felder

He earned the Ph.D. degree in Technology, Management and Policy from MIT in 2001. He is an assistant professor of Management Science at Manhattan College in Riverdale, New York. His research interests are in reliability analysis and management of restructured electric power systems.