A Proposed Design for a Short-Term Resource Adequacy Program

Pablo A. Ruiz, *Student Member, IEEE*, and George Gross, *Fellow, IEEE*

***Abstract*— Short-term resource adequacy is the ability of a system with a set of given resources to meet the load over the short term. In the aftermath of the 2000–2001 California crisis, focus on resource adequacy has come to the forefront of market design issues. Various approaches, such as capacity requirements, capacity payments and financial options requirements, have been proposed to ensure resource adequacy in electricity markets. We propose a design of a short-term resource adequacy program based on capacity requirements expressed in terms of a price sensitive demand curve. The program is formulated so as to give incentives for providing capacity to markets and to mete out penalties for non-performance situations. The probabilistic modeling of the uncertainty in the availability of generating resources and in the load allows the evaluation of reliability in terms of widely-used metrics. Through the explicit representation of the strategic behavior of market players, capacity withholding impacts are directly measurable. The analysis of the proposed design and the simulation of a simple implementation show that the program results in improved reliability. Reduction of the total system costs are obtained when key program parameters are appropriately chosen. The design has proven effective under an extensive range of different scenarios in the various systems tested. The improvements attainable with the implementation of the program design are illustrated with representative simulation results on different sized systems. The proposed design with the ability to evaluate the linkage between reliability and markets contributes to the electricity market design area.**

***Index Terms*— capacity payments, capacity requirements, capacity withholding, electricity markets, incentives, reliability, reliability economics, resource adequacy.**

I. Introduction

A power system is said to be reliable when all the consumers receive their demanded electricity with the desired quality. The study of electric system reliability consists of the investigation of system security and system adequacy. Security is the ability of the system to withstand sudden disturbances. Adequacy is the ability of the system to meet the aggregate customer demand with a certain probability [1], usually given as 1 day in 10 years. Resource adequacy addresses the need to have "sufficient" resources in place to meet the forecasted demand taking into account the uncertainty of the environment and the salient characteristics of electricity, including the lack of large-scale storage and the limited demand responsiveness of load to price. Under the conventional vertically integrated structure, the reliability decisions were the responsibility of the utility that owned and operated the resources and the transmission network. In the market environment, an independent entity, which we refer to by the generic term independent grid operator or IGO, is responsible for system reliability. Our focus is on the resource adequacy decisions made by the IGO over periods with durations of the order of months. For such periods, the resource mix remains fixed and the only decision variables for ensuring resource adequacy in electricity markets are the offered capacities of the existing supply sources and the demand bids of price responsive buyers.

The regulatory framework of the vertically integrated utility structure imposed the *obligation to serve* on the utilities and provided a regulated rate of return on the investments undertaken. Thus, the utilities' interests were in making the investments necessary for reliability on which they earned an assured stream of returns. Under restructuring, although usually the load serving entities or LSEs remain saddled with the obligation to serve, resource adequacy assurance has become more complex. With the increased complexity, major problems arise: short-term resource adequacy problems were a major concern in the 2000–2001 California electricity crisis.

In all electricity markets, be they energy or ancillary services markets, the use of capacity is traded. Since sellers need not offer all their capacity to serve the demand, they may engage in so-called *physical capacity withholding* or *capacity gaming* [2]. Any withholding action impairs the reliability, and consequently the short-term resource adequacy depends heavily on market player behavior. In fact, absent the formulation of specific rules, withholding may result in capacity deficiency, which has become a concern in various jurisdictions [3]. The FERC attempts of standarizing market design recognize the importance of the resource adequacy issue to well functioning markets [3]. Industry attempts to implement mechanisms to effectively address the resource adequacy issues clearly recognize the need for effective solutions.

An extensive review of resource adequacy, although mainly focused on long-term issues, is provided in [4]. The proposed approaches to ensure resource adequacy may be classified into various categories [4]–[7]: capacity requirements [8]–[10], capacity payments [11], financial options requirements [5], [12], strategic reserve [4] and capacity subscriptions [4]. Capacity requirements have been the preferred approach in the U.S. electricity markets and so we focus on them. Under this

Research supported in part by PSERC under the Markets and Reliability project.

The authors are with the Department of Electrical and Computer Engineering, University of Illinois at Urbana-Champaign, Urbana, IL 61801, USA (e-mails: paruiz@ieee.org; gross@uiuc.edu)

approach, requirements for either unforced capacity[1] (UCAP) or installed capacity (ICAP) are imposed by the IGO on each LSE. These requirements must be met on a periodic basis, which vary from days to years-ahead [8], [9]. The LSEs may self-provide or purchase from firms physically able to deliver energy and power. The suppliers of UCAP/ICAP are obligated to submit financially meaningful offers for each hour in the day-ahead electricity markets for every day of the month, and to provide the services committed to under the accepted offers.

The implementations of such programs have been in constant flux, with frequent design changes being introduced in light of the deficiencies encountered after implementation. The re-design to establish effective resource adequacy programs is associated with needs for analysis tools to help in their design and implementation. In this paper, we address these needs for the resource adequacy programs for the short-term period of our focus.

Our objective is to propose a design of a short-term resource adequacy program for electricity markets. The proposed design harnesses market forces to provide short-term resource adequacy and in doing so establishes an *explicit linkage between reliability and economics*. The design is based on capacity requirements expressed in terms of a price sensitive demand curve. A "carrots and sticks" approach is used to give incentives for providing capacity to markets and mete out penalties for non-performance situations. The design requires the tuning of key design parameters, including the specification of capacity requirements parameters and penalty coefficient values. The analysis of the proposed program shows that it results in improved reliability. We have tested the proposed design via simulation on test systems varying from 10 to 100 generators, and under a wide variety of conditions. In every case of each tested system, the implementation of the design results in reliability improvements. Extensive sensitivity studies with different tunable parameter values show that reduced total system costs can be attained with the proposed program when parameters are judiciously selected. We illustrate the impacts of the program with representative results on different sized test systems. The design and analysis work of this paper serves as a useful tool in the assessment and the enhancement of short-term resource adequacy programs. As such, it constitutes a contribution in reliability economics and furthers the state of the art in electricity market design.

The paper contains five more sections. In the next section, we describe the models and metrics used in the design. In section III, we introduce the design proposal, which we analyze in section IV. In section V, we present the illustrative simulation study results. We make concluding remarks and discuss the scope of further work in the last section.

II. Analytic Framework

We use the framework discussed in detail in [13]. We consider an isolated system operated by an IGO and assume that no transmission constraints are binding. As such, no congestion exists and we ignore all other network constraints and considerations. The conventional approach to adequacy evaluation is based on the physical characteristics of the resources and does not consider market outcomes [14]. As we consider the economic impacts on reliability, the models of the day-ahead market and the sellers' behavior are needed.

A. Modeling in the hourly time-frame

We define one hour as the smallest indecomposable unit of time. The time horizon of interest is H hours, where H is, typically, the number of hours in a month. In our discussion of the day-ahead market and seller behavior models, we focus on a snapshot of the system in hour h. For each hour h of the day-ahead market, we model the total system demand as the sum of the load forecast ℓ_h and a random component denoted by the random variable (r.v.) $\underset{\sim}{\Delta L}_h$. For simplicity, we assume that

$$\underset{\sim}{\Delta L}_h = \begin{cases} 0 & \text{with probability } p_h \\ \Delta\ell_h > 0 & \text{with probability } \left(1-p_h\right), \end{cases} \tag{1}$$

where $\Delta\ell_h$ shows the variability of the demand from its forecast[2]. There are S generation firms denoted by $s^1, s^2, ..., s^S$. We assume the available capacity α^i_{jh} of generator j of seller s^i in hour h is a known deterministic variable in the day-ahead[3] of the hour h. We denote the available capacity of seller s^i in hour h by $\alpha^i_h = \sum_j \alpha^i_{jh}$.

We consider a pool market paradigm, where we assume the energy and reserves markets are combined into the single *energy and reserves market* (ERM) [15, p. 121]. Each seller's offer in the ERM must be backed by deliverable capacity and energy, and each buyer's bid is accompanied by the obligation to take delivery of the purchases.

We further assume the demand of each buyer is fixed and independent of the ERM prices. Thus, the total demand is fixed and independent of the ERM prices[4]. The total market demand for energy is ℓ_h *MWh*, and the total market demand for reserves is β_h *MW*. The specification of β_h takes explicitly into account the $\Delta\ell_h$ impacts. Sellers submit offers for their generators and we model the capacity of each generator by a set of blocks whose capacities sum to the generator capacity. The generator j block k offer of seller s^i with capacity κ^{ik}_{jh} is defined by the energy and reserves *offer prices* $\sigma^{ik}_{jh} \in \left[0, \bar{\rho}_e\right]$ and $\varsigma^{ik}_{jh} \in \left[0, \bar{\rho}_r\right]$, respectively, with the reserves *capacity* $\mu^{ik}_{jh} \le \kappa^{ik}_{jh}$. Sellers cannot offer at prices above the offer caps[5] $\bar{\rho}_e$ and $\bar{\rho}_r$, which limit *economic*

[1] Unforced capacity is installed capacity de-rated to take into account the unavailability of the unit.

[2] We limit our consideration to the cases $\Delta\ell_h > 0$ since resource adequacy for $\Delta\ell_h > 0$ implies resource adequacy for $\Delta\ell_h \le 0$.

[3] The supply uncertainty is incorporated in the H-hour time frame.

[4] Price-dependent demand chooses not to buy if prices reach the price cap. Under scarcity conditions, prices reach their caps and so the total demand is equal to the price-independent demand. As our focus is on reliability, we only consider price-independent demand. The value of this price-independent demand is taken into account in the reliability metrics.

[5] Offer caps are used in markets such as NYISO [16], PJM and ISO-NE.

withholding. To construct the market model we define the vectors $\underline{\boldsymbol{\sigma}}_h$, $\underline{\boldsymbol{\varsigma}}_h$, $\underline{\boldsymbol{\kappa}}_h$ and $\underline{\boldsymbol{\mu}}_h$ consisting of the block offer prices and capacities of all the sellers. We similarly construct the vectors $\underline{\boldsymbol{e}}_h$ and $\underline{\boldsymbol{r}}_h$, consisting of the energy and reserves provided by all the block offers. For notational simplicity, in the remainder of our discussion we drop the index h.

The IGO determines the hour h ERM outcomes by maximizing the *social welfare* [17]. Under the price-independent demand assumption, the maximization of the social welfare is equivalent to the minimization of the cost function $\mathscr{C}(\cdot,\cdot)$ in the ERM to meet the energy and reserves needs and are given by

$$\mathscr{C}(\underline{\boldsymbol{e}},\underline{\boldsymbol{r}}) \triangleq \underline{\boldsymbol{\sigma}}'\underline{\boldsymbol{e}} + \underline{\boldsymbol{\varsigma}}'\underline{\boldsymbol{r}} . \tag{2}$$

The decision-making process to determine the optimal $\underline{\boldsymbol{e}}^*$ and $\underline{\boldsymbol{r}}^*$ entails the solution of the linear programming problem

$$\left.\begin{aligned} &\min_{\underline{\boldsymbol{e}},\underline{\boldsymbol{r}}} \ \mathscr{C}(\underline{\boldsymbol{e}},\underline{\boldsymbol{r}}) \\ &s.t. \\ &\qquad \underline{\mathbf{1}}'\underline{\boldsymbol{e}} = \ell \quad \leftrightarrow \quad \rho_e \\ &\qquad \underline{\mathbf{1}}'\underline{\boldsymbol{r}} = \beta \quad \leftrightarrow \quad \rho_r \\ &\qquad \underline{\boldsymbol{e}} + \underline{\boldsymbol{r}} \le \underline{\boldsymbol{\kappa}} \\ &\qquad \underline{\boldsymbol{r}} \le \underline{\boldsymbol{\mu}} \\ &\qquad \underline{\boldsymbol{e}},\underline{\boldsymbol{r}} \ge \underline{\boldsymbol{0}} \end{aligned}\right\} ERMP \tag{3}$$

In (3), the costs of serving the forecasted demand plus having reserves in case the demand exceeds its forecasted value are minimized. We associate with the optimal solution of (3) the energy and reserves prices ρ_e^* *\$/MWh* and ρ_r^* *\$/MW*, respectively. If *ERMP* is feasible, these are equal to the offer prices of the most expensively priced blocks producing energy and providing reserves, respectively. Note that reserves providers receive the energy price in addition to the reserves price whenever they are asked to produce energy also using the reserves serving blocks. As there are two distinct commodities sold in the ERM, a block offering to sell energy and reserves with offer prices below the market clearing price will sell the commodity that provides the largest savings to the IGO [18]. We denote the total capacity offered by seller s^i by κ_T^i. The total capacity offered by all sellers is

$$\kappa_T = \sum_{i=1}^{S} \kappa_T^i . \tag{4}$$

In cases of shortage, i.e., $\kappa_T < \ell$, (3) is infeasible. For the demand met, the ERM prices are limited by the administratively set ERM price caps $\bar{\bar{\rho}}_e$ and $\bar{\bar{\rho}}_r$ for energy and reserves, respectively. The caps are set so that $\bar{\bar{\rho}}_e > \bar{\rho}_e$ and $\bar{\bar{\rho}}_r > \bar{\rho}_r$ so as to recognize *scarcity rents* [19]. In light of the physical deliverability requirement on each seller's offers, the ERM constitutes, in effect, a *physical* market.

We next discuss the modeling of the market sellers' behavior. Since the load is uncertain, the energy sold by the reserves providers is uncertain, and so each seller's profits are uncertain. We assume each seller is risk neutral and has an objective to maximize its expected profits in formulating its offer. We further assume that each seller opts to offer all its available capacity, unless the expected profits obtained withholding capacity are strictly larger than the expected profits obtained offering all the available capacity.

We distinguish between two types of sellers—*price takers* and *price setters* [20, p. 46], also known as *strategic sellers* [15, p. 40]. While price takers cannot affect market prices, strategic sellers do affect market prices. A price taker optimizes its offering strategy by offering all its available capacity at marginal costs [15, p. 80], [21]. The details of the price takers' offers are provided in [18, p. 30].

For simplicity, we assume that there is a single strategic seller $s^{\hat{i}}$. We assume that the strategic seller has perfect information on its competitors' offers for the hour h ERM. The decision of seller $s^{\hat{i}}$ is on amounts $e^{\hat{i}}$ of energy and $r^{\hat{i}}$ of reserves to sell in the ERM, with

$$e^{\hat{i}} = \sum_j \sum_k e_j^{\hat{i}k} \quad \text{and} \quad r^{\hat{i}} = \sum_j \sum_k r_j^{\hat{i}k} . \tag{5}$$

Since the seller $s^{\hat{i}}$ impacts the market prices, we write them as explicit functions of $e^{\hat{i}}$ and $r^{\hat{i}}$:

$$\rho_e^* = \rho_e^{\hat{i}}\left(e^{\hat{i}},r^{\hat{i}}\right) \quad \text{and} \quad \rho_r^* = \rho_r^{\hat{i}}\left(e^{\hat{i}},r^{\hat{i}}\right). \tag{6}$$

These functions are effectively the *residual demand* functions for the strategic seller, and can be constructed in view of the perfect information assumption. These functions take into account the optimality conditions of the *ERMP*. The two-tuple $(e^{\hat{i}},r^{\hat{i}})$ is attainable if and only if there exists an offer that lets seller $s^{\hat{i}}$ sell $e^{\hat{i}}$ *MWh* and $r^{\hat{i}}$ *MW*. We show in [18] that a two-tuple $(e^{\hat{i}},r^{\hat{i}})$ is attainable if and only if it satisfies:

- seller $s^{\hat{i}}$ sells nonnegative quantities: $e^{\hat{i}},r^{\hat{i}} \ge 0$,
- the sales do not exceed the available capacity $\alpha^{\hat{i}}$, and
- whenever $r^{\hat{i}}$ is positive, the purchase of reserves from seller $s^{\hat{i}}$ at the lowest possible offer price – 0 *\$/MW* – gives more savings to the IGO than buying energy from seller $s^{\hat{i}}$ at the highest possible offer price – $\bar{\rho}_e$ *\$/MWh*.

The attainable set $\mathscr{F}^{\hat{i}}$ of two-tuples $(e^{\hat{i}},r^{\hat{i}})$ is defined as

$$\mathscr{F}^{\hat{i}} \triangleq \left\{ \begin{aligned} &\left(e^{\hat{i}},r^{\hat{i}}\right) \ge 0 : e^{\hat{i}} + r^{\hat{i}} \le \alpha^{\hat{i}}, \\ &r^{\hat{i}}\left[\rho_e^{\hat{i}}\left(e^{\hat{i}},r^{\hat{i}}\right) - \bar{\rho}_e\right] \le r^{\hat{i}}\rho_r^{\hat{i}}\left(e^{\hat{i}},r^{\hat{i}}\right) \end{aligned} \right\}. \tag{7}$$

Seller $s^{\hat{i}}$ selects the attainable two-tuple $(e^{\hat{i}**},r^{\hat{i}**})$ that maximizes its expected profits. Since the reserves sellers receive the energy price whenever they are also required to provide energy, the expected profits depend on the probability distribution of the load r.v. With $\beta = \Delta\ell$ and neglecting the costs of reserves, the expected profits of seller $s^{\hat{i}}$ are

$$\begin{aligned} \Pi^{\hat{i}}\left(e^{\hat{i}},r^{\hat{i}}\right) = {} & p\left[\rho_e^{\hat{i}}\left(e^{\hat{i}},r^{\hat{i}}\right)e^{\hat{i}} - \chi_e^{\hat{i}}\left(e^{\hat{i}}\right) + \rho_r^{\hat{i}}\left(e^{\hat{i}},r^{\hat{i}}\right)r^{\hat{i}}\right] \\ & + (1-p)\left[\rho_e^{\hat{i}}\left(e^{\hat{i}},r^{\hat{i}}\right)\left(e^{\hat{i}}+r^{\hat{i}}\right)\right. \\ & \left. - \chi_e^{\hat{i}}\left(e^{\hat{i}}+r^{\hat{i}}\right) + \rho_r^{\hat{i}}\left(e^{\hat{i}},r^{\hat{i}}\right)r^{\hat{i}}\right], \end{aligned} \tag{8}$$

where $\chi_e^{\hat{i}}(\cdot)$ is the energy production costs function. The strategic seller determines $e^{\hat{i}**}$ and $r^{\hat{i}**}$ as the solution of

$$\Pi^{\hat{i}}\left(e^{\hat{i}**},r^{\hat{i}**}\right)=\max_{e^{\hat{i}},r^{\hat{i}}}\left\{\Pi^{\hat{i}}\left(e^{\hat{i}},r^{\hat{i}}\right),\left(e^{\hat{i}},r^{\hat{i}}\right)\in\mathbb{F}^{\hat{i}}\right\}\quad SSP\,.^{6}\ (9)$$

The decision variables in (9) are sale quantities, not offer parameters. Once $(e^{\hat{i}**},r^{\hat{i}**})$ is known, seller $s^{\hat{i}}$ constructs an offer to attain its objective of selling $e^{\hat{i}**}$ *MWh* and $r^{\hat{i}**}$ *MW* in the ERM [18, p. 93]. By the perfect information assumption, the solutions of the *SSP* and the *ERMP* are related by

$$e^{\hat{i}*}=e^{\hat{i}**}\ \text{and}\ r^{\hat{i}*}=r^{\hat{i}**}. \qquad (10)$$

Whenever shortage occurs, prices are set to the price caps, i.e.,

$$\bar{\bar{\rho}}_e=\rho_e^{\hat{i}}(e^{\hat{i}**},r^{\hat{i}**})>\bar{\rho}_e\ \text{and/or}\ \bar{\bar{\rho}}_r=\rho_r^{\hat{i}}(e^{\hat{i}**},r^{\hat{i}**})>\bar{\rho}_r, \qquad (11)$$

and so every offer price is below the market clearing price. Thus, if seller $s^{\hat{i}}$ were to offer $\kappa_T^{\hat{i}}>e^{\hat{i}**}+r^{\hat{i}**}$, then he would sell more energy and/or reserves than the optimal two-tuple $(e^{\hat{i}**},r^{\hat{i}**})$. Hence, whenever (11) holds the strategic seller offers a total capacity of exactly $e^{\hat{i}**}+r^{\hat{i}**}$. Therefore,

$$\kappa_T=\begin{cases}\sum_{i:i\neq\hat{i}}\alpha^{i}+e^{\hat{i}**}+r^{\hat{i}**} & \text{if (10) holds}\\ \sum_{i}\alpha^{i} & \text{otherwise.}\end{cases} \qquad (12)$$

Thus, the conditions under which seller $s^{\hat{i}}$ exercises physical withholding are (11) and

$$e^{\hat{i}**}+r^{\hat{i}**}<\alpha^{\hat{i}}. \qquad (13)$$

An example of physical withholding is given in [13]. Clearly, without mitigation, i.e., $\bar{\bar{\rho}}_e=\bar{\rho}_e$ and $\bar{\bar{\rho}}_r=\bar{\rho}_r$, (11) would never hold and so there would be no physical withholding. This concludes our discussion of the models for hour-*h*.

B. Modeling in the H-hour time-frame

We next discuss the modeling of the physical load and generation resources during the *H*-hour period for the purposes of reliability evaluation. We represent the system's total demand in the *H*-hour period by the r.v. $\underset{\sim}{L}$. If the system is in hour *h*, then $\underset{\sim}{L}=\underset{\sim}{L}_h$. Using conditional probability,

$$\boldsymbol{P}\left\{\underset{\sim}{L}=\underset{\sim}{L}_h\,\middle|\,\text{hour } h\right\}=1. \qquad (14)$$

The distribution of $\underset{\sim}{L}$ is constructed in the Appendix. The *peak load* ℓ^{p} is defined as the maximum value $\underset{\sim}{L}$ may attain during the *H*-hour period,

$$\ell^{p}\triangleq\max_{1\le h\le H}\left\{\ell_h+\Delta\ell_h\right\}. \qquad (15)$$

We use the 2-state conventional model for the available generation in the *H*-hour period. We assume, as is widely done in reliability assessment, that the units have uniform characteristics throughout the period. The *available capacity* of generator *j* controlled by seller s^{i} is modeled by the r.v. $\underset{\sim}{A}_j^{i}$,

$$\underset{\sim}{A}_j^{i}=\begin{cases}g_j^{i} & \textit{with probability } a_j^{i}\\ 0 & \textit{with probability } \left(1-a_j^{i}\right).\end{cases} \qquad (16)$$

Here, g_j^{i} is the capacity and a_j^{i} is the *availability* of the unit *j* of seller s^{i}. The r.v.s $\underset{\sim}{A}_j^{i}$ are assumed to be independent of one another and also of $\underset{\sim}{L}$. The total capacity of seller s^{i} is denoted by g^{i}, and the total available capacity is denoted by the r.v. $\underset{\sim}{A}^{i}=\sum_j\underset{\sim}{A}_j^{i}$. The system available capacity is denoted by the r.v.

$$\underset{\sim}{A}=\sum_i\underset{\sim}{A}^{i}. \qquad (17)$$

We assess the system reliability in the *H*-hour period with the usual metrics used in reliability analysis [14]:

(i) the *loss of load probability* given by

$$\boldsymbol{P}\left\{\underset{\sim}{L}>\underset{\sim}{A}\right\};$$

(ii) the *expected unserved energy* evaluated using

$$H\cdot\boldsymbol{E}\left\{\underset{\sim}{L}-\underset{\sim}{A}\,\middle|\,\underset{\sim}{L}>\underset{\sim}{A}\right\}\cdot\boldsymbol{P}\left\{\underset{\sim}{L}>\underset{\sim}{A}\right\};$$

and,

(iii) the *expected outage costs* defined by

$$w\cdot H\cdot\boldsymbol{E}\left\{\underset{\sim}{L}-\underset{\sim}{A}\,\middle|\,\underset{\sim}{L}>\underset{\sim}{A}\right\}\cdot\boldsymbol{P}\left\{\underset{\sim}{L}>\underset{\sim}{A}\right\}.$$

The per unit *MWh* outage cost *w* [22] is used in the assessment of the economic impacts. We explicitly distinguish the metric functions from their values by using the notation $LOLP$, $\mathscr{U}$, and $\mathscr{C}_o$, respectively, for their values.

Next, we incorporate the impacts of the market on reliability. The uncertainty in the available capacity for the month-ahead period leads to uncertainty in the sellers' offers, and therefore in the capacity offered in the ERM and the ERM costs. To represent this uncertainty, we examine the distributions of the uncertain total capacity $\underset{\sim}{K}$ offered in the ERM, and the uncertain ERM costs $\underset{\sim}{C}$. For the system in hour *h* with the given available capacities, $\underset{\sim}{C}=\mathscr{C}_h\left(\underline{\boldsymbol{e}}_h^{*},\underline{\boldsymbol{r}}_h^{*}\right)$ and $\underset{\sim}{K}=\kappa_{Th}$ are obtained from (3) and (12), respectively. We make use of the conditional probability information

$$\boldsymbol{P}\left\{\underset{\sim}{K}=\kappa_{Th}\,\middle|\,\{\text{hour } h\}\cap\left\{\underset{\sim}{A}_j^{i}=\alpha_{jh}^{i}\ \forall i,j\right\}\right\}=1 \qquad (18)$$

and

$$\boldsymbol{P}\left\{\underset{\sim}{C}=\mathscr{C}_h\left(\underline{\boldsymbol{e}}_h^{*},\underline{\boldsymbol{r}}_h^{*}\right)\,\middle|\,\{\text{hour } h\}\cap\left\{\underset{\sim}{A}_j^{i}=\alpha_{jh}^{i}\ \forall i,j\right\}\right\}=1. \qquad (19)$$

The distributions of $\underset{\sim}{K}$ and $\underset{\sim}{C}$ are constructed in the Appendix. Since every offer in the ERM represents physical capacity,

$$\boldsymbol{P}\left\{\underset{\sim}{K}\le\underset{\sim}{A}\right\}=1. \qquad (20)$$

In competitive markets, reliability depends on the sellers' behavior in the market. We explicitly incorporate market effects by replacing $\underset{\sim}{A}$ by the total offered capacity $\underset{\sim}{K}$ in evaluating the metrics *(i) – (iii)*, and denote with the superscript *M* the values taken by these metrics as a result of the ERM outcomes:

$$LOLP^{M}=\boldsymbol{P}\left\{\underset{\sim}{L}>\underset{\sim}{K}\right\}, \qquad (21)$$

[6] The *SSP* is a nonlinear optimization problem with a discontinuous objective function and a cumbersome feasible set due to the multiple products sold (energy and reserves). Its efficient solution has not been studied yet, and so we use an exhaustive search for the solution of the *SSP*.

$$\mathscr{U}^M = H \cdot \boldsymbol{E}\{\underset{\sim}{L} - \underset{\sim}{K} \,|\, \underset{\sim}{L} > \underset{\sim}{K}\} \cdot \boldsymbol{P}\{\underset{\sim}{L} > \underset{\sim}{K}\}, \quad (22)$$

$$\mathscr{C}_o^M = w \cdot H \cdot \boldsymbol{E}\{\underset{\sim}{L} - \underset{\sim}{K} \,|\, \underset{\sim}{L} > \underset{\sim}{K}\} \cdot \boldsymbol{P}\{\underset{\sim}{L} > \underset{\sim}{K}\}. \quad (23)$$

Due to (20), *LOLP*, $\mathscr{U}$, and $\mathscr{C}_o$ provide a lower bound for $LOLP^M$, $\mathscr{U}^M$, and $\mathscr{C}_o^M$, respectively, and so we refer to *LOLP*, $\mathscr{U}$, and $\mathscr{C}_o$ as the *limiting values* for $LOLP^M$, $\mathscr{U}^M$, and $\mathscr{C}_o^M$. The *supply costs* $\mathscr{C}_s$ are

$$\mathscr{C}_s \triangleq H \cdot \boldsymbol{E}\{\underset{\sim}{C}\}, \quad (24)$$

and provide a measure of the sellers' revenues and the LSEs' payments in the *H*-hour period. The possibility of physical withholding implies that $\underset{\sim}{K}$ need not be equal to $\underset{\sim}{A}$. Indeed, $\underset{\sim}{K} < \underset{\sim}{A}$ if and only if there is physical withholding.

III. Program Design

We make use of the analytic development in Section II to propose our design of a short-term resource adequacy program. The proposed program is based on the capacity requirements approach. The vehicle for meeting the capacity requirements are the so-called *monthly capacity credits* [8]. Monthly capacity credits are bilateral contracts between a seller and the IGO that obligate the seller to submit offers in the day-ahead electricity market for each hour of the month and to deliver all the services committed to under the accepted offers. We view monthly capacity credits for a specified available capacity[7] c *MW* as a set of contracts, each of one hour duration, with the contract for each hour *h* of the month being for the capacity c. We refer to these one-hour contracts as the *hourly capacity credits*.

We use a single buyer[8] for capacity credits – the IGO – responsible for purchasing the quantity of capacity credits capable of meeting the total capacity requirements. The IGO recovers all its payments for the capacity credits from the LSEs. The single buyer situation obviates the need for penalties on the LSEs to enforce the purchase of the capacity credits. Whenever a seller of hourly capacity credits fails to comply with its obligation, an explicit monetary penalty is imposed for each such hour regardless of the reasons for noncompliance and notwithstanding any prior notification to the IGO.

The proposed program design aims to improve reliability. Whenever the monetary value assigned to the marginal reliability improvement is smaller (larger) than the asking price for the capacity credits, the demand for capacity credits should be reduced (increased) so that the price for capacity credits matches the monetary value assigned to the marginal reliability improvement. To explicitly represent the trade-off between reliability improvements and capacity credits costs, we allow the requirements to be price-dependent, explicitly linking reliability and economics. Some examples for price-dependent requirements are presented in [23].

Monthly capacity credits are traded in the capacity credits market (CCM). For each month, the CCM is cleared using a uniform-price double-auction market mechanism. The IGO submits the pre-specified demand curve[9], determined by the price-dependent capacity credits requirements, and the generation firms submit offers of capacity credits to the CCM. The offers and the demand curve are used to determine the total market clearing quantity, each individual seller's quantity, and the market clearing price. Prices in the CCM are not capped, to avoid the possibility of physical withholding. The price-dependent demand curve limits the market clearing prices and the possibility to exercise economic withholding. The market clearing price is paid to each seller of monthly capacity credits by the IGO.

The obligations on the sellers of capacity credits and the explicit monetary penalty mechanism entail that a seller of hourly capacity credits is effectively selling a commitment to have actual available capacity for that hour and offer it in the market. We introduce flexibility in the proposed program design by allowing secondary trading of hourly capacity credits among firms *physically* capable to deliver energy and power. As such, the capacity used to fulfill the sellers' obligations need not belong to the same firm that sold the capacity credits in the CCM for every hour *h* of the month. The secondary trading gives the possibility to sellers to avoid the payment of penalties by transferring the obligations to another firm.

We next discuss the rationale for the proposed design. The CCM provides an opportunity for the generation firms to increase profits. Thus, all firms have incentives to participate in the CCM. Each firm whose submitted offers to the CCM are accepted, gets to sell capacity credits and receives the corresponding payments. However, capacity credits sellers are penalized whenever they fail to meet their commitments by not participating in the ERM, i.e., withholding capacity. Consequently, the proposed program provides disincentives to capacity credits sellers to withhold capacity. The situation of CCM sellers is in direct contrast to that of generation firms not selling capacity credits and therefore not receiving capacity payments. Since the firms submit their offers in the CCM knowing the value of the disincentive, the proposed program provides a balanced incentive/disincentive mechanism to generation firms so as to submit offers in the ERM. The revenues that capacity credits sellers receive in the CCM compensate for foregone opportunities to exercise physical withholding in the ERM.

The time line of the program is as follows. On a month-ahead basis, the monthly CCM takes place. Between the times

[7] Although capacity credits are usually expressed in terms of unforced capacity, we express them in terms of available capacity. If one expresses them in terms of unforced capacity, the underlying assumption is that the capacity may be unavailable. Thus, being unavailable and not submitting offers is not incompliance; it is actually expected and contemplated in the contract. By using available capacity, the definition of capacity credits is made consistent with the objectives of the program.

[8] The single buyer procurement recognizes the fact that physical capacity withholding impacts all LSEs by decreasing reliability and increasing prices. An alternative to the single buyer procurement is to leave the responsibility of purchasing capacity credits to the individual LSEs, and, if necessary, impose penalties on LSEs which do not purchase enough capacity credits. The analytic developments of Section IV hold for this alternative, as the single-buyer assumption is only used to aggregate the bids.

[9] The demand curve in a single buyer situation has to be designed and agreed upon by the LSEs, to avoid giving the IGO incentives to manipulate the CCM as a monopolist buyer.

the CCM and the ERM take place, generation firms are allowed to engage in capacity credits trades among themselves. We point out that before the ERM outcomes are determined, all markets are financial. This means, in particular, that capacity credits are not linked to the actual physical units. After the ERM clears, the outcomes have physical attributes since the specific accepted offers of energy and reserves are associated with particular physical units.

An implementation of the proposed design must comply with the rules of the CCM, have the capability to construct the price-dependent capacity credits requirements function and specify the penalty function. Both functions have tunable parameters that need to be carefully adjusted according to the needs of specific jurisdictions. The distinguishing features of the program design are the following:

- the formulation of a price-sensitive demand function which provides a direct linkage between reliability and market economics;
- specification of a market-based incentive mechanism to encourage generation firms to submit offers in the ERM; and,
- specification of explicit monetary penalties for noncompliance with commitments made.

We next analyze the proposed program design in terms of its economic and reliability impacts in the *H*-hour period, and also discuss some insights obtained from a simple implementation of the program.

IV. Program Modeling and Analysis

We start our discussion with the CCM model. The CCM covers the capacity needs for each hour in the *H*-hour period. We denote by $\Theta^i(c)$ the integral over the interval [0,*c*] of the seller s^i marginal offer price to the CCM. We denote by $\xi^i \leq g^i$ the amount of capacity credits offered in the CCM by seller s^i. The amount sold by seller s^i is c^i. We construct the vectors $\underline{\xi}$ and $\underline{c}$, from the components ξ^i and c^i, respectively. The capacity credits demand curve $\Phi(\cdot)$ is submitted by the IGO to the CCM. The total capacity credits purchased by the IGO is c_b.

The CCM is cleared by maximizing the *social welfare* $\mathscr{S}(\underline{c}, c_b)$ while ensuring that the supply-demand balance is satisfied. Consequently, the CCM entails the solution of the following optimization problem:

$$\left.\begin{array}{l} \max\limits_{\underline{c},\, c_b} \ \mathscr{S}(\underline{c}, c_b) = \int_0^{c_b} \Phi(y)\,dy - \sum_{i=1}^{S} \Theta^i(c^i) \\ s.t. \\ \quad \underline{\mathbf{1}}'\underline{c} - c_b = 0 \leftrightarrow \ \rho_c \\ \qquad \underline{c} \leq \underline{\xi} \\ \qquad \underline{c}, c_b \geq 0 \end{array}\right\} CCMP \qquad (25)$$

The optimal solution $(\underline{c}^*, c_b^*)$ of (25) determines the sales and purchases in the CCM, and the optimal value ρ_c^* of the dual variable for the supply-demand balance determines the CCM clearing price. The capacity credits payments $\mathscr{P}_c$ made by the single buyer are

$$\mathscr{P}_c = \rho_c^* \, c_b^* \,. \qquad (26)$$

Note that, by its very nature, the CCM is a financial market and the outcomes $\underline{c}^*$ are only financially binding. Also, these outcomes may be modified in the secondary markets for capacity credits.

In light of the pivotal role of the strategic seller in influencing the reliability of the system, we next study the impacts of the proposed design on the strategic seller behavior in a particular hour *h* of the ERM. Let $\Psi(c^{\hat{i}}, \kappa_T^{\hat{i}})$ denote the penalty imposed on the strategic seller $s^{\hat{i}}$ with the commitment to provide $c^{\hat{i}}$ *MW* of capacity credits but with the offer of $\kappa_T^{\hat{i}}$ *MW* in the ERM. In the proposed design, we formulate the penalty $\Psi(\cdot,\cdot)$ as a monotonically non-decreasing function of the difference $c^{\hat{i}} - \kappa_T^{\hat{i}}$. The *net expected profits* of seller $s^{\hat{i}}$ in the ERM for providing $e^{\hat{i}}$ *MWh* of energy and $r^{\hat{i}}$ *MW* of reserves given the impacts of the CCM commitment are

$$\breve{\Pi}^{\hat{i}}(e^{\hat{i}}, r^{\hat{i}}, \kappa_T^{\hat{i}}, c^{\hat{i}}) \triangleq \Pi^{\hat{i}}(e^{\hat{i}}, r^{\hat{i}}) - \Psi(c^{\hat{i}}, \kappa_T^{\hat{i}}) \,. \qquad (27)$$

Whenever seller $s^{\hat{i}}$ provides some capacity credits, his net expected profits are maximized by selecting $(e^{\hat{i}}, r^{\hat{i}}, \kappa_T^{\hat{i}})$ with the profits in (27), replacing $\Pi^{\hat{i}}(\cdot,\cdot)$ in the *SSP*. Note that if the strategic seller sells capacity credits, his profits depend on $\kappa_T^{\hat{i}}$ explicitly. Moreover, if $c^{\hat{i}}$ is equal to seller $s^{\hat{i}}$'s available capacity, any amount of capacity withholding entails a penalty, thus the disincentives to withhold are explicit. We analyze the change $\Delta\kappa_T$ in κ_T corresponding to a change $\Delta c^{\hat{i}} > 0$ in the capacity credits provided by seller $s^{\hat{i}}$. When the optimal solution of *SSP* satisfies the conditions in (11), i.e., when there is no economic withholding, the presence of the penalty term ensures that $\Delta\kappa_T \geq 0$. However, when the conditions in (11) do not hold, seller $s^{\hat{i}}$ may economically withhold, and so the change $\Delta c^{\hat{i}} > 0$ may have no impacts on κ_T. We can easily show that any scaling of the penalty function by a constant greater than 1 results in similar changes. Thus, the proposed program induces the desired behavior in that the offered quantities are not reduced when penalties and capacity credits quantities are increased.

We next discuss the modeling of the sellers' behavior in the CCM. A price taker optimizes its offering strategy by offering all its capacity at marginal costs [15, p. 80], [21]. For a price taker, the costs of providing capacity credits include the penalties due to forced outages and the payments for trading the obligation in secondary markets. Given the opportunity for secondary trading and the uncertainty on the available capacity, the capacity credit costs are uncertain. An upper bound for the expected costs of the price takers is easily determined by assuming the trading price in the secondary markets is equal to the penalty. This bound makes sense since the alternative is simply to pay the penalty. The costs incurred by a strategic seller are the difference in net expected ERM profits when it does not sell capacity credits versus when it does sell. As such, the foregone profits due to a reduction in market power opportunities are explicitly considered. Hence, the strategic player can exploit those foregone opportunities without having to withhold capacity. To construct his offer for the CCM, the strategic seller follows a similar process to that for the ERM. That is, the residual demand is obtained; then the optimal quantity to be sold is chosen, and an offer that attains the optimal sales is constructed. This process is relatively standard, in contrast to the one for the ERM, since only one type of contract is traded in the CCM, and there are no price caps.

We now turn to the evaluation of reliability effects, and for that purpose we compare the reliability evaluation with and without the proposed program. A *reliability improvement* with the program entails a *nonnegative decrease* in the reliability metrics' values from those without the program. Moreover, we term the improvement as *positive* if the decrease in the value of at least one of the reliability metrics is positive. We can prove the following theorems:

Theorem 1*: The proposed program improves reliability.*■

This is a consequence of the fact that increasing the CCM purchases does not reduce the capacity offered in the ERM.

We introduce the notion of *perfect compliance* in the program. Perfect compliance means that the generation firms meet their commitments by submitting offers into the ERM sufficient to cover the requirements for every hour *h* of the *H*-hour period. We consider perfect compliance under two possible cases:

- the available capacity exceeds c_b^* : perfect compliance requires the total capacity offered in the ERM to be at least as large as c_b^* ; and,
- the available capacity is less than or equal to c_b^* : perfect compliance requires all the available capacity to be offered in the ERM.

Under perfect compliance, we have analytical conditions that ensure positive reliability improvements:

Theorem 2*: We consider the case of perfect compliance of the sellers. If the ERM available capacity* $\underset{\sim}{K}_0$ *without a resource adequacy program satisfies either*

$$\boldsymbol{P}\left\{\left\{\underset{\sim}{K}_0 < \underset{\sim}{L}\right\} \cap \left\{\underset{\sim}{K}_0 < c_b^* \le \underset{\sim}{A}\right\}\right\} > 0 \tag{28}$$

or

$$\boldsymbol{P}\left\{\left\{\underset{\sim}{K}_0 < \underset{\sim}{L}\right\} \cap \left\{\underset{\sim}{K}_0 < \underset{\sim}{A} < c_b^*\right\}\right\} > 0 , \tag{29}$$

then, the proposed program results in a positive improvement of reliability. ■

In other words, if *a)* there is perfect compliance, *b)* physical capacity withholding is practiced without the program so that reliability is hurt, and *c)* enough capacity credits are bought, then the improvement in reliability is positive.

To ensure a positive reliability improvement, the reliability metrics without the program must not attain their limiting values defined in section II. In fact, we can show that the capacity credits required for a positive reliability improvement have a limiting value dependent on the forecasted peak load in

Theorem 3: *Under perfect compliance with* $c_b^* = \ell^p$ *, the program implies that the reliability metrics attain their limiting values.* ■

That is, under perfect compliance there is no reason to buy more capacity credits than the forecasted peak load. The proofs of these three theorems are given in [18].

We can gain additional insights into the proposed program design impacts by considering a simple implementation. The implementation uses a piece-wise linear function $\Phi\left(\cdot\right)$ for the capacity credits requirements curve and is expressed as

$$\Phi\left(c_b\right) = max\left\{c_b^{max} - c_b , 0\right\} \cdot m, \quad c_b \ge 0 , \tag{30}$$

where the slope of the capacity credits demand curve is given by $-m$, and c_b^{max} is the minimum demand with a zero bid price. The implementation uses a simple fixed penalty coefficient $v > 0$ *\$/MW*, and so the penalty function $\Psi\left(\cdot,\cdot\right)$ is stated as

$$\Psi\left(c^i , \kappa_T^i\right) = max\left\{c^i - \kappa_T^i , 0\right\} \cdot v . \tag{31}$$

The capacity credits requirements curve in this implementation has two tunable parameters, c_b^{max} and *m*. Since the price bid for capacity credits above c_b^{max} is 0, and therefore the marginal benefits of any quantity of capacity credits above c_b^{max} is also 0, it follows that an appropriate choice for c_b^{max} is ℓ^p, Thus, the parameter c_b^{max} may be interpreted as the amount of capacity credits above which reliability cannot improve. From Theorem 3, we know that under perfect compliance, purchases of capacity credits in an amount exceeding ℓ^p cannot bring further reliability improvements beyond those obtained for credits in the amount ℓ^p. Hence, the marginal value of capacity credits exceeding ℓ^p is zero, and so we set c_b^{max} equal to ℓ^p in this simple implementation.

The simple penalty function in (31) has the tunable parameter *v*. A seller s^i, who commits to provide c^i *MW* of capacity credits but fails to participate in the ERM, is assessed a penalty of $v c^i$. The choice of *v* is very important, and we can guarantee perfect compliance by setting

$$v = \bar{v} \triangleq \max_{1 \le i \le S}\left\{g^i\left[max\left\{\bar{\bar{\rho}}_e - \bar{\rho}_e , \bar{\bar{\rho}}_r - \bar{\rho}_r\right\}\right]\right\} . \tag{32}$$

This follows from the fact that $\bar{v}$ is larger than or equal to the largest possible increase in profits a seller may obtain by physically withholding 1 *MW* from the ERM. However, setting $v = \bar{v}$ may be overly punitive, since as the penalty coefficient *v* increases, the payments $\mathscr{P}_c$ increase. Therefore, *v* needs to be *sufficiently large* so as to *encourage* the compliance of the selling firms participating in the resource adequacy program, but not *exceedingly large* so as to render the resource adequacy program not cost effective. We note that the relationship (32) implies that as the g^i s are reduced, $\bar{v}$ is reduced. Moreover, since $\bar{v}$ is a direct function of the

TABLE I
TEST SYSTEMS DATA

test system	A	B
number of generation firms	8	87
total number of generators	10	100
peak demand (MW)	1650	17800
capacity margin (%)	42.4	19.1
strategic seller's market share (%)	32.0	11.8
market cap for energy ($/MWh)	150	150
market cap for reserves ($/MWh)	30	30
offer cap for energy ($/MWh)	70	90

TABLE II
CAPACITY CREDITS MARKET CLEARING RESULTS FOR THE TWO TEST SYSTEMS

test system	A	B
ρ_c^* ($/MW)	$0.72\ 10^3$	$1.44\ 10^3$
c_b^* (MW)	$1.63\ 10^3$	$1.78\ 10^4$
$\mathscr{P}_c$ ($)	$1.17\ 10^6$	$2.56\ 10^7$

TABLE III
RELIABILITY METRICS VALUES WITH THE IMPLEMENTED PROGRAM IN THE TWO TEST SYSTEMS

test system	A	B
$LOLP^M$	$0.72\ 10^{-2}$	$1.35\ 10^{-3} \pm 0.09\%$
$\mathscr{U}^M$ (MWh)	$0.79\ 10^3$	$1.28\ 10^2 \pm 0.11\%$
$\mathscr{C}_s$ ($)	$5.73\ 10^7$	$3.19\ 10^8 \pm 0.19\%$
$\mathscr{C}_s + \mathscr{C}_o^M + \mathscr{P}_c$ ($)	$5.92\ 10^7$	$3.61\ 10^8 \pm 0.30\%$

TABLE IV
REFERENCE CASE METRICS VALUES IN THE TWO TEST SYSTEMS

	test system	A		B	
	case	no program	no withholding	no program	no withholding
value of metrics	$LOLP^M$	$1.57\ 10^{-2}$	$0.34\ 10^{-2}$	$2.70\ 10^{-3}$ ±1.41%	$0.06\ 10^{-3}$ ±0.25%
	$\mathscr{U}^M$ (MWh)	$1.72\ 10^3$	$0.31\ 10^3$	$3.55\ 10^2$ ±1.36%	$0.15\ 10^2$ ±0.35%
	$\mathscr{C}_s$ ($)	$5.81\ 10^7$	$4.48\ 10^7$	$3.20\ 10^8$ ±0.19%	$1.10\ 10^8$ ±0.19%
	$\mathscr{C}_s + \mathscr{C}_o^M$ ($)	$5.96\ 10^7$	$4.51\ 10^7$	$3.57\ 10^8$ ±1.55%	$1.10\ 10^8$ ±0.54%

differences of the caps, as the differences decrease, $\bar{v}$ decreases. In the case where $\bar{\rho}_e = \bar{\bar{\rho}}_e$ and $\bar{\rho}_r = \bar{\bar{\rho}}_r$, every nonnegative penalty coefficient guarantees perfect compliance. We discuss in the next section representative results of the extensive simulations we carried out of this simple implementation of the proposed program design on various test systems and under various scenarios.

V. SIMULATION STUDIES

We use the results of simulation studies on two test systems to be a representative illustration of the effectiveness of the program to improve reliability. We provide a summary of the data for the two test systems in Table I. We selected the two test systems due to their different resource mixes and differences in the strategic seller's market shares. The complete data for the two test systems and an extensive presentation of the simulation results is provided in [18].

We next present the assessment of the impacts of the implementation of the proposed program in the test systems. The values of the program parameters used are $v = 10$ $/MW, $m = 40$ $/MW^2, and $c_b^{max} = 1650$ MW for test system A, and $v = 20$ $/MW, $m = 50$ $/MW^2, and $c_b^{max} = 17800$ MW for test system B. We assume that each price taker offers its generation at the upper bound for the expected costs, $vH\left(1 - a_j^i\right)$ $/MW, and so we obtain upper bounds for the capacity credits price and payments. We further assume that the strategic seller can trade his commitments in the secondary markets at 0 $/MW as long as the price takers have more available capacity than the credits they sold. The CCM market clearing results are given in Table II. Due to the relatively high price-dependency of the demand curve, we find that it is in the strategic seller's interest no to exercise market power in the CCM. Hence, prices are set by the least reliable (lowest availability) price taking generator selling capacity credits. The values of the reliability metrics presented in Table III are obtained using conditional probability on the values of the load and available capacity r.v.s. The results obtained for system A are exact. For system B, Monte Carlo simulation was used [24], [25] in light of the large number of generators, and so the reliability metric values have the associated errors given in the table.

The expected ERM profits of system A's strategic seller with and without the program are $\$1.14\ 10^7$ and $\$1.15\ 10^7$, respectively. The decrease in ERM profits is more than compensated by the CCM revenues, which total $\$0.05\ 10^7$. Thus, the strategic seller is paid to decrease the exercise of physical withholding.

In Table IV, we measure the improvements due to the proposed program by computing the values of the metrics with and without the program. We note that there are reliability improvements in both test systems. The total system costs $\left(\mathscr{C}_o^M + \mathscr{C}_s + \mathscr{P}_c\right)$ decrease with the design implementation in test system A but increase in the test system B. The reason for this is that in test system A, the reduction in $\left(\mathscr{C}_o^M + \mathscr{C}_s\right)$ is larger than the increase in $\mathscr{P}_c$, while in test system B this is not true, due to the presence of a higher penalty coefficient.

We also study the sensitivity of reliability and market efficiency metrics to changes in the penalty coefficient value. We present representative results using test system B. We start with the sensitivity of $\mathscr{U}^M$ with respect to changes in v, when the capacity credits bought are 17,800 MW. The numerical results are plotted in Fig. 1. Without a penalty, i.e., $v = 0$ $/MW, there is no program enforcement and so there is no change in the reliability from the case without a program. As the penalty increases, the compliance in the program improves and so the unserved energy decreases. A change in the ownership of a unit may affect the value of the resource adequacy metrics. To see this, we considered the sensitivity

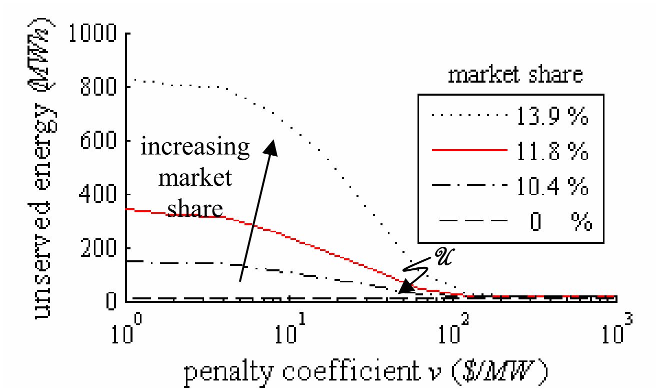

Fig. 1. Unserved energy of test system B as a function of the penalty coefficient and the market share of the strategic seller.

cases with the strategic seller controlling one extra generator and one generator less than in the base case, with the total generation capacity fixed; the results are shown with the dotted and the dash-dotted curves in Fig. 1. As the strategic seller increases its market share, the amount of capacity that can be physically withheld increases, and so $\mathscr{U}^M$ increases.

Next, we study the sensitivity of the supply costs $\mathscr{C}_s$ to changes in v. We obtain that as the penalty increases, $\mathscr{C}_s$ decreases since the exercise of physical capacity withholding is reduced. By the assumption on the price takers' offer prices, the CCM prices are a piecewise linear function of v. The costs $\mathscr{P}_c$ of capacity credits to the system are found to be almost proportional to the penalty coefficient for values of v in the range [0,50] *$/MW*. Hence, too large a penalty coefficient may result in prohibitively large program costs.

We next discuss the tuning of the penalty coefficient for given values of c_b^{max} and m, with the objective of minimizing the total costs[10] $\left(\mathscr{C}_o^M + \mathscr{C}_s + \mathscr{P}_c\right)$. We discuss the results using test system B, whose total costs are higher with the program. The total costs are found to be a convex function of v, and so the optimal penalty v^* is the value at which the derivative of the total costs with respect to v equals 0. We provide an interpretation of this optimal penalty in Fig. 2. For $v < v^*$, the reduction in the costs of supply and outage costs are larger than the increase in capacity costs, and so increasing the penalty coefficient is optimal. For $v > v^*$ we have the opposite effect. We see that there is a range of values for v such that the program reduces the total costs for the given values of m and c_b^{max}. Hence, the program can decrease the total costs when the tunable program parameters are appropriately selected.

VI. Summary and Further Work

In this paper we have presented a design of a short-term resource adequacy program. In the analysis and simulation of the program, we explicitly assessed the impacts of the strategic behavior of market participants. The program implementation improves reliability with respect to the case without a resource adequacy program. Moreover, the total system costs can be reduced if the tunable program parameters are appropriately chosen. The proposed design with the ability to evaluate the linkage between reliability and markets contributes to the developing area of electricity market design.

The extensions of the work include the incorporation of demand responsiveness to price, multiple seller interactions, inter-hour relationships and transmission network effects into the models. With the extended modeling, the basic design can be further extended to include the capacity credits providers' geographic location and the price responsiveness characteristics of the various demand-side players. Another area for further research is the formulation, analysis and comparison of different *(i)* capacity requirements that appropriately account for the benefits capacity provides to the system, *(ii)* effective penalty schemes that provide the desired disincentives for non-compliance, and *(iii)* market compatible short-term resource adequacy programs, using forward contracts and call options, for example. Also, there is a need to investigate the market power opportunities arising with the design implementation and their impact on resource adequacy, and to devise mitigation schemes to discourage/prevent them, whenever applicable. Double-price-caps schemes also deserve further research. In particular, the study of their inclusion in the optimization of the tunable parameters would provide useful insights on the relationship market power mitigation rules and reliability. Finally, the extension of the work to long-term resource adequacy can provide a basis for solving a critical need for the industry in the competitive environment.

Appendix: Distribution Functions of $\underset{\sim}{L}$, $\underset{\sim}{K}$ and $\underset{\sim}{D}$

Since the distribution of $\underset{\sim}{L}_h$ is known and fixed,

$$\boldsymbol{P}\left\{\underset{\sim}{L} \le \ell\right\} = \sum_{h=1}^{H} \boldsymbol{P}\left\{\underset{\sim}{L} = \underset{\sim}{L}_h \,\middle|\, \text{hour } h\right\} \cdot \boldsymbol{P}\left\{\text{hour } h\right\} \cdot \boldsymbol{P}\left\{\underset{\sim}{L}_h \le \ell\right\}. \quad (33)$$

Using (1), (14), and the fact that there are H hours in the period, we obtain

$$\boldsymbol{P}\left\{\underset{\sim}{L} \le \ell\right\} = \frac{1}{H}\left[\sum_{h:\ell_h \le \ell} p_h + \sum_{h:\ell_h + \Delta\ell_h \le \ell} \left(1 - p_h\right)\right]. \quad (34)$$

To explicitly state the distributions of $\underset{\sim}{K}$ and $\underset{\sim}{D}$, we construct the random vector $\underset{\sim}{\boldsymbol{A}}$ consisting of the available capacity r.v. of each generator. We denote a realization of $\underset{\sim}{\boldsymbol{A}}$

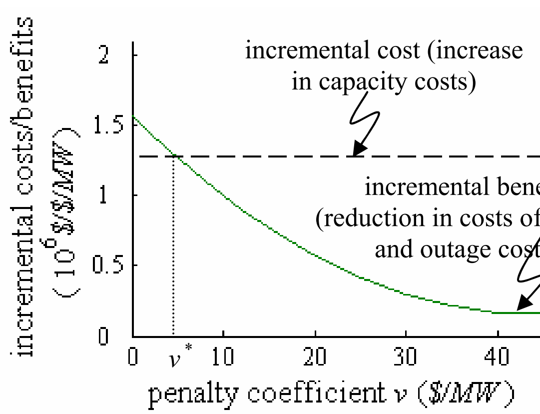

Fig. 2. Incremental costs and benefits in test system B with respect to a change in the penalty, as a function of the penalty coefficient.

[10] As our focus is on the theoretical aspects of the program, we ignore the costs of implementing the program. In a practical implementation, they should also be taken into account.

by the vector $\underline{\boldsymbol{\alpha}}_z = \left[\alpha^1_{1z}, \alpha^1_{2z}, \ldots, \alpha^1_{G^1 z}, \alpha^2_{1z}, \ldots, \alpha^S_{G^S z} \right]'$, where G^i is the number of generators of seller s^i. There are 2^G such realizations, where G is the total number of generators. The probability of $\underline{\boldsymbol{\alpha}}_z$ occurring is given by

$$\boldsymbol{P}\left\{ \underset{\sim}{\underline{\boldsymbol{A}}} = \underline{\boldsymbol{\alpha}}_z \right\} = \prod_i \prod_j \left[a^i_j \boldsymbol{P}\left\{ \alpha^i_{jz} = g^i_j \right\} + \left(1 - a^i_j\right) \boldsymbol{P}\left\{ \alpha^i_{jz} = 0 \right\} \right]. \quad (35)$$

Since the distribution of $\underset{\sim}{\underline{\boldsymbol{A}}}$ is time independent,

$$\boldsymbol{P}\left\{ \underset{\sim}{K} \le \kappa \right\} = \sum_{h=1}^{H} \sum_{z} \boldsymbol{P}\left\{ \underset{\sim}{K} \le \kappa \,\middle|\, \{\text{hour } h\} \cap \left\{ \underset{\sim}{\underline{\boldsymbol{A}}} = \underline{\boldsymbol{\alpha}}_z \right\} \right\} \cdot \boldsymbol{P}\{\text{hour } h\} \cdot \boldsymbol{P}\left\{ \underset{\sim}{\underline{\boldsymbol{A}}} = \underline{\boldsymbol{\alpha}}_z \right\}. \quad (36)$$

Using (18) and the fact that there are H hours in the period, we obtain

$$\boldsymbol{P}\left\{ \underset{\sim}{K} \le \kappa \right\} = \frac{1}{H} \sum_{h=1}^{H} \sum_{z : \kappa_{T h z} \le \kappa} \boldsymbol{P}\left\{ \underset{\sim}{\underline{\boldsymbol{A}}} = \underline{\boldsymbol{\alpha}}_z \right\}. \quad (37)$$

Similarly,

$$\boldsymbol{P}\left\{ \underset{\sim}{D} \le d \right\} = \frac{1}{H} \sum_{h=1}^{H} \sum_{z : d_{hz} \le d} \boldsymbol{P}\left\{ \underset{\sim}{\underline{\boldsymbol{A}}} = \underline{\boldsymbol{\alpha}}_z \right\}. \quad (38)$$

If the number of generators is large, Monte Carlo simulation [24], [25] can be used to estimate the distributions of $\underset{\sim}{K}$ and $\underset{\sim}{D}$. Note, however, that the distribution of $\underset{\sim}{K}$ does not need to be explicitly computed if one is only interested in the reliability metrics computation, since it is taken into account in the Monte Carlo sampling.

References

[1] Glossary of Terms Task Force, *Glossary of Terms*, North American Electric Reliability Council, Princeton, NJ, May 2006, www.nerc.com/pub/sys/all_updl/standards/rs/Glossary_02May06.pdf.

[2] D. McGillis, I. Fichtenbaum, M. Michailiuk and F. Galiana, "The effect of capacity gaming on the cost of system reliability," in *Proc Canadian Conf of Elect and Comp Eng*, vol. 2, pp. 917 – 921, May 2004.

[3] FERC, "Standard market design notice of proposed rulemaking," July 31,2002,http://www.ferc.gov/industries/electric/indus-act/smd/nopr.asp.

[4] L. J. de Vries, "Securing the public interest in electricity generation markets," Ph.D. dissertation, Department of Electrical and Computer Engineering, Technische Universiteit Delft, Netherlands, 2004, http://www.tbm.tudelft.nl/webstaf/laurensv/LJdeVries_dissertation.pdf.

[5] S. S. Oren, "Generation adequacy via call options obligations: safe passage to the promised land," *The Electricity Journal*, vol. 18, no. 9, pp. 28-42, Nov 2005.

[6] S. S. Oren, "Capacity payments and supply adequacy in competitive electricity markets," in *Anais do VII SEPOPE*, Curitiba, Brazil, May 2000.

[7] A. Papalexopoulos, "Supplying the generation to meet the demand," *IEEE Power & Energy Mag*, vol. 2, issue 4, pp. 66 – 73, Jul-Aug 2004.

[8] "NYISO installed capacity manual," Version 4, NYISO, Schenectady, NY, Apr 2003, www.nyiso.com/services/documents/manuals.

[9] "Reliability assurance agreement among load serving entities in the MAAC control zone," PJM Interconnection, Valley Forge, PA, Feb 2006, www.pjm.com/documents/downloads/agreements/raa.pdf.

[10] B. F. Hobbs, J. Iñón and S. E. Stoft, "Installed capacity requirements and price caps: oil on the water, or fuel on the fire?," *The Electricity Journal*, vol. 14, no. 6, pp. 23-34, Jul. 2001.

[11] A. Chuang and F. F. Wu, "Capacity payments and the pricing of reliability in competitive generation markets," in *IEEE Proc of the 33rd Hawaii Conf on System Sciences*, 2000.

[12] C. Vázquez, M. Rivier and I. Perez-Arriaga, "A market approach to long-term security of supply," *IEEE Trans on Power Systems*, vol. 17, no. 2, pp. 349 – 357, May 2002.

[13] P. A. Ruiz and G. Gross, "An analytical framework for short-term resource adequacy in competitive electricity markets," in *Proc of the IX PMAPS*, Session 1:7, pp. 1 – 7, 11-15 June 2006, Stockholm, Sweden.

[14] J. Endrenyi, *Reliability Modeling in Electric Power Systems*, New York, NY: Wiley, 1978.

[15] D. Kirschen and G. Strbac, *Fundamentals of Power System Economics*, West Sussex, England: John Wiley & Sons Ltd, 2004.

[16] R. de Mello, et al., "The use of conduct and impact tests in the mitigation of market power," in *IEEE Proc of the Power Sys Conf and Expo*, vol. 2, pp. 868 – 873, Oct. 2004.

[17] F. Schwepe, et al., *Spot Pricing of Electricity*, Norwell, MA: Kluwer, 1988, p. 33.

[18] P. A. Ruiz, "A proposed design for a short-term resource adequacy program," M.S. thesis, Department of Electrical and Computer Engineering, University of Illinois, Urbana-Champaign, 2005, http://energy.ece.uiuc.edu/gross/papers/pabloThesis.pdf.

[19] S. Stoft, *Power System Economics: Designing Markets for Electricity*. Piscataway, NY: IEEE Press, 2002, p. 70.

[20] J. Perloff, *Microeconomics*, 2nd edition, Boston, MA: Addison – Wesley, 2001.

[21] G. Gross and D. Finlay, "Generation supply bidding in perfectly competitive electricity markets," *Computational and Mathematical Organization Theory*, vol. 6, no. 1, pp. 83 – 98, May 2000.

[22] K. Kariuki and R. Allan, "Evaluation of reliability worth and value of lost load," *IEE Proceedings – Generation, Transmission and Distribution*, vol. 143, no. 2, pp. 171 – 180, March 1996.

[23] B. F. Hobbs, J. Iñón, M. Hu, S. Stoft and M. Bhavaraju, "A dynamic analysis of a demand curve-based capacity market proposal: the PJM reliability pricing model," submitted to *IEEE Trans on Power Systems*, January 2006.

[24] C. Singh, T. P. Chander and J. Feng, "Convergence characteristics of two Monte Carlo models for reliability evaluation of interconnected power systems," *Electric Power Systems Research*, vol. 28, no. 1, pp. 1 – 9, Oct. 1993.

[25] R. Rubinstein, *Simulation and the Monte Carlo Method*, New York, NY: John Wiley & Sons, 1981.

Pablo A. Ruiz (S'05) obtained the degree of Ingeniero Electricista from the Universidad Tecnológica Nacional – Santa Fe, Argentina, in 2002, and the M. Sc. degree in Electrical Engineering from the University of Illinois at Urbana-Champaign, USA, in 2005. He is currently pursuing a Ph.D. in Electrical Engineering at the University of Illinois at Urbana-Champaign, USA. His research interests include power systems computations, control, economics, operations, planning and reliability.

George Gross (F'88) is Professor of Electrical and Computer Engineering and Professor, Institute of Government and Public Affairs, at the University of Illinois at Urbana-Champaign. His current research and teaching activities are in the areas of power system analysis, planning, economics and operations and utility regulatory policy and industry restructuring. In the 1999-2000 academic year, he was invited to be a Visiting Professor at a number of Italian institutions including University of Pavia, Politecnico di Milano and Politecnico di Torino. His undergraduate work was completed at McGill University, and he earned his graduate degrees from the University of California, Berkeley. He was previously employed by Pacific Gas and Electric Company in various technical, policy and management positions. Dr. Gross won the Franz Edelman Management Science Achievement Award in 1985 and several prize paper awards. He has consulted widely to organizations in North and South America, Europe and Asia.