Short-Term Resource Adequacy in Electricity Market Design

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***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, the consideration of resource adequacy in market design became critically important. Various capacity approaches, such as requirements, payments, and subscriptions, have been proposed to ensure resource adequacy in electricity markets. We focus on short-term resource adequacy design and analysis within the context of making effective use of competition 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 gives incentives for providing capacity to markets and metes out penalties for non-performance situations. The probabilistic modeling of the uncertainty in the generation availability and in the load allows the evaluation of reliability in terms of widely-used metrics. The analysis of the proposed design and the simulation of a simple implementation on different sized test systems show that the program results in improved reliability. These studies indicate that the total system costs may be minimized when key program parameters are appropriately chosen. The proposed design provides a meaningful linkage between reliability and markets and constitutes a contribution to the electricity market design.**

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

I. Introduction

Adequacy, a fundamental component of system reliability, is the ability of the system to meet the aggregate customer demand with the appropriate quality [1]. 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 need to match supply and demand around the clock. 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 of *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. While in many jurisdictions, under restructuring, 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 as seen in California, where short-term resource adequacy was a major concern in the 2000–2001 crisis.

Capacity is at the heart of both the energy and the capacity-based ancillary services markets. Since sellers need not offer all their capacity to serve the demand, they may engage in so-called *physical capacity withholding* [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 to standardize market design clearly recognize the importance of resource adequacy issues in the efficient functioning of markets [3].

A variety of programs has been proposed to address resource adequacy issues in electricity markets. These are extensively reviewed in [4], with a primary focus on long-term aspects. These programs have been in constant flux, with frequent design changes being introduced in light of the deficiencies encountered after implementation.

Our objective is to discuss short-term resource adequacy design and analysis in the electricity markets context. We propose a design of a program that 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 to mete out penalties for non-performance situations. The analysis of the proposed program and the simulation using a simple implementation on different sized test systems show that the program results in improved reliability. Extensive sensitivity studies, in which various parameter values are varied, indicate that total system costs may be reduced with the proposed program when the parameter values are judiciously selected. 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

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reliability economics and furthers the state of the art in electricity market design.

The paper contains five more sections and two appendices. In the next section, we discuss the design of a short-term resource adequacy program. We introduce the models and metrics for the analysis and simulation in section III. In section IV we deploy these models and present the analytical results. We illustrate the proposed design with simulation study results in section V. We make concluding remarks and discuss the scope of further work in the last section. The appendices contain the nomenclature and some theoretical results.

II. Resource Adequacy Program Design

Resource adequacy has been approached in a variety of ways in electricity market design. The proposed approaches may be classified into various categories [4]–[7]. The principal scheme types include capacity requirements [8]–[10], capacity payments [11], financial options requirements [5], [12], strategic reserves [4] and capacity subscriptions [4], [13]. Capacity requirements have been the preferred approach in U.S. electricity markets and for this reason we focus on them.

In the capacity requirements approach, the obligation to serve of the LSEs leads to *capacity credits* requirements on each LSE. The satisfaction of these requirements is enforced by the IGO. 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 specified period and to deliver all the services committed to under the accepted offers. These requirements must be met on a specified periodic basis, which may range from days to years-ahead [8], [9]. The LSEs may self-provide or purchase from firms physically able to deliver energy and power. Capacity credits are usually expressed in terms of installed capacity (ICAP) or unforced capacity (UCAP) [8], i.e., installed capacity derated to take into account the unit's unreliability.

Both capacity credits and *reserves* provide a form of insurance to the IGO to cover capacity deficiencies during actual operations. Such insurance is needed to improve the ability of the power system to reliably meet the load around the clock. The capacity requirements, which typically cover periods from days to months and sometime years, serve to ensure that adequate capacity is in place to meet the demand during the period covered and to improve the competitiveness of electricity markets. In contrast, reserves have a response time from minutes to hours, and are used to provide the capability to overcome potential deficiencies due to changes in the load or the occurrence of contingencies. Reserves and capacity credits may be viewed as distinct products and therefore they are traded in different markets.

We propose a program design using the capacity requirements approach. For concreteness, we choose a one-month period. We view *monthly capacity credits* for a specified capacity c *MW* as a set of contracts, each of one hour duration for each hour h of the month. We refer to these one-hour contracts as the *hourly capacity credits*. Rather than expressing capacity credits in terms of UCAP, as is usually done [8], we do so in terms of available capacity to explicitly model uncertainty. Available capacity is the capacity that materializes in the real-time, and as such it is probabilistic in nature. UCAP, a deterministic quantity, could be thought of as the expected value of the available capacity. By using available capacity, we can explicitly incorporate the objective of having capacity offered to satisfy the energy and reserve needs in the definition of capacity credits. An accompanying effect is a simplification in program enforcement.

Given the wide responsibilities of the IGO for reliability, we view the IGO as the single buyer responsible for purchasing the capacity credits to meet 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.

A key component of the proposed program design is the specification of a price-dependent capacity requirements curve. Such a curve represents the trade-off between reliability improvements and program costs. Some examples for price-dependent requirements are presented in [24].

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. Firms submit offers of capacity credits to the CCM. To avoid the possibility of physical withholding, offer prices in the CCM are not capped. The IGO uses the demand curve, constructed from the information provided by the LSEs, and the offers to determine the total market clearing quantity, each individual seller's quantity, and the market clearing price. The price-dependent demand curve limits the market clearing prices and the incentives to exercise *economic withholding*. Each seller of monthly capacity credits is paid the market clearing price.

The obligations on the sellers of capacity credits and the penalty mechanism entail that a seller of hourly capacity credits is effectively selling a commitment to have 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 CCM provides an opportunity for the selling firms to increase profits. Thus, all firms have incentives to participate in the CCM. Each firm that sells capacity credits, receives the corresponding payments. Capacity credits sellers are penalized whenever they fail to meet their commitments by not participating in the *energy and reserves market* (ERM), i.e., withholding capacity. Consequently, the proposed program provides disincentives to capacity credits sellers to withhold capacity. The situation of capacity credits sellers is in direct contrast to that of firms not selling capacity credits and therefore not receiving capacity payments. The proposed program provides an incentive/disincentive mechanism to firms so as to submit offers in the ERM. Note that all generation firms are allowed to offer in the ERM, regardless of whether or not the firm submits offers in the CCM.

The capacity credits revenues that sellers receive compensate for foregone opportunities to exercise physical withholding in the ERM. Thus, market power is not eliminated, but is "bought out" in advance to reduce incentives to hurt reliability. This is conceptually similar to the way capacity payments [11] and subscriptions [13], and options requirements [5] work in the short-term. In the strategic reserve [4] approach, a "neutral" agent, such as the IGO, owns capacity that is only used in scarcity conditions. Hence, strategic reserve provides physical insurance and reduces the market share of the "non-neutral" firms.

The time line of the program is as follows. On a month-ahead basis, the monthly CCM takes place. Between the times 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 may be financial. This means, in particular, that capacity credits are not linked to the actual physical units. The ERM clearance determines the outcomes of the accepted offers of energy and reserves, which are associated with particular physical units.

The principal similarities of the program design with the programs implemented in the Northeast markets [8], [9] include:

- the use of capacity credits markets with double-auction mechanisms;
- the formulation of a price-sensitive demand function which takes into account the trade-off between reliability improvements and capacity credits costs.

The main features that distinguish the program include

- the specification of capacity credits in terms of available capacity;
- authorization of capacity credits secondary trading;
- assessment of explicit monetary penalties in case of noncompliance with commitments made.

III. Resource Adequacy Models

In this section we discuss the modeling needs in short-term resource adequacy studies and the particular models used in sections IV and V. Short-term resource adequacy is impacted by the market design, by the behavior of market participants and by the uncertainty in the availability of generating resources and in the load. Conceptually, we build a 2-layer framework with a layer for the models of the markets and the market participants and another layer for the load and the generation resources models, as shown in Figure 1 [14]. The use of market information together with physical information allows us to take into account *a)* physical constraints in the market clearing process, and *b)* market effects in the evaluation of resource adequacy metrics. We next describe the models used for the analysis and simulation of the proposed program. The models are discussed in [15] in more detail.

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

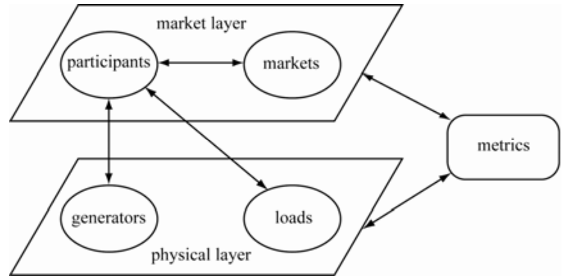

Fig. 1. The two-layer short-term resource adequacy framework.

constraints and considerations.

A. The hour h modeling

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. The uncertainty in supply in this period is explicitly represented. 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 random variable (r.v.) $\underset{\sim}{L}_h$, with known probability mass function $p_h(\cdot)$. We consider a system with S selling firms denoted by $s^1, s^2, \ldots, s^i, \ldots, s^S$. We assume the available generation capacity α_h^i in hour h of seller s^i is known in the day-ahead.

We consider a pool market paradigm, where we assume the energy and reserves markets are combined into the single ERM [17, 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 purchased quantities.

We further assume the total demand for energy and reserves is fixed and independent of the ERM prices. The rationale for this assumption is that as our focus is on reliability, we only consider the demand which would buy regardless of the market price. The total demand for energy is the forecasted load ℓ_h *MWh*, and the total demand for reserves is the reserve requirement β_h *MW*. Sellers submit an increasing piecewise constant function as their offer. Sellers offer prices for energy and reserves cannot exceed the offer caps[1] $\bar{\rho}_e$ and $\bar{\rho}_r$, respectively. To construct the market model, we define the vectors $\underline{\boldsymbol{\sigma}}_h$ and $\underline{\boldsymbol{\varsigma}}_h$ consisting of offer prices for energy and reserves, respectively, $\underline{\boldsymbol{\kappa}}_h$ and $\underline{\boldsymbol{\mu}}_h$ consisting of offer capacities (quantities) and $\underline{\boldsymbol{e}}_h$ and $\underline{\boldsymbol{r}}_h$, consisting of energy and reserves sold by each accepted offer. 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* [19]. Under the price-independent demand assumption, the maximization of the

[1] Markets such as PJM, ISO-NE and NYISO [18] have offer price caps to limit the opportunities for economic withholding. The effects of these caps have not been thoroughly investigated in the literature.

social welfare is equivalent to the minimization of the costs of serving the demand and providing the needed reserves. Hence, the optimal $\underline{e}^*$ and $\underline{r}^*$ are obtained from the solution of the linear programming problem

$$\left.\begin{array}{l} \min\limits_{\underline{e},\underline{r}} \; \underline{\sigma}'\underline{e} + \underline{\varsigma}'\underline{r} \\ s.t. \\ \qquad \underline{\mathbf{1}}'\underline{e} = \ell \quad \leftrightarrow \quad \rho_e \\ \qquad \underline{\mathbf{1}}'\underline{r} = \beta \quad \leftrightarrow \quad \rho_r \\ \qquad \underline{e} + \underline{r} \leq \underline{\kappa} \\ \qquad \underline{r} \leq \underline{\mu} \\ \qquad \underline{e}, \underline{r} \geq \underline{0} \end{array}\right\} \; ERMP \qquad (1)$$

We associate with the optimal solution of (1) the energy and reserves prices ρ_e^* *\$/MWh* and ρ_r^* *\$/MW*, respectively. Reserves providers receive the energy price in addition to the reserves price whenever they are asked to produce energy also using the reserves serving generators. As there are two distinct commodities sold in the ERM, an offer to sell energy and reserves with offer prices below the market clearing price will sell the commodity that provides the best combination to the IGO [15]. The total capacity offered by all sellers is

$$\kappa = \sum_{i=1}^{S} \kappa^i . \qquad (2)$$

In cases of shortage, e.g., $\kappa < \ell$ or $\underline{\mathbf{1}}'\underline{\mu} < \beta$, (1) is infeasible. The ERM prices in these cases are the administratively set ERM price caps $\bar{\bar{\rho}}_e$ and $\bar{\bar{\rho}}_r$ for energy and reserves, respectively. The caps satisfy $\bar{\bar{\rho}}_e > \bar{\rho}_e$ and $\bar{\bar{\rho}}_r > \bar{\rho}_r$ so as to recognize *scarcity rents* [20], as is the case in actual markets. The difference between the scarcity prices and the maximum prices without scarcity may create incentives to physically withhold capacity. Without this difference, we show at the end of this section that physical withholding is not profitable.

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 the 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* [21, p. 46], also known as *strategic sellers* [17, 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 [17, p. 80], [22]. Additional details on the price takers' offers are found in [15, p. 30].

For simplicity, we assume that there is a single[2] strategic seller $\hat{s}$. We assume that the strategic seller has perfect information on its competitors' offers for the hour h ERM. This information is used to determine the *residual demand* functions (sale prices as a function of the total sale quantities $(\hat{e},\hat{r})$) for seller $\hat{s}$. Let the *attainable* set $\hat{\mathbb{F}}$ be the set of two-tuples $(\hat{e},\hat{r})$ that can result from (1) for feasible $\underline{\sigma}$, $\underline{\varsigma}$, $\underline{\kappa}$ and $\underline{\mu}$; the attainable set is discussed in detail in the Appendix. Seller $\hat{s}$ selects the attainable two-tuple $(\hat{e}^{**},\hat{r}^{**})$ that maximizes its expected profits $\hat{\Pi}(\cdot,\cdot)$,

$$\hat{\Pi}(\hat{e}^{**},\hat{r}^{**}) = \max_{\hat{e},\hat{r}} \left\{ \hat{\Pi}(\hat{e},\hat{r}), (\hat{e},\hat{r}) \in \hat{\mathbb{F}} \right\}. \qquad (3)$$

The decision variables in the strategic seller problem[3] (3), or *SSP*, are the sale amounts, not the offer parameters. Once $(\hat{e}^{**},\hat{r}^{**})$ is known, seller $\hat{s}$ constructs an offer to attain its objective of selling $\hat{e}^{**}$ *MWh* and $\hat{r}^{**}$ *MW* in the ERM [15, p. 93]. Due to the perfect information assumption, $(\hat{e}^{**},\hat{r}^{**})$ is obtained with the same set of price takers' offers as used in the ERM. Therefore, the solutions of (1) and (3) are related by

$$\hat{e}^* = \hat{e}^{**} \text{ and } \hat{r}^* = \hat{r}^{**} . \qquad (4)$$

Whenever shortages occur, prices are set to the price caps, i.e.,

$$\bar{\bar{\rho}}_e = \hat{\rho}_e(\hat{e}^{**},\hat{r}^{**}) > \bar{\rho}_e \text{ and/or } \bar{\bar{\rho}}_r = \hat{\rho}_r(\hat{e}^{**},\hat{r}^{**}) > \bar{\rho}_r, \qquad (5)$$

and so every offer price is below the market clearing price. Thus, if seller $\hat{s}$ were to offer $\hat{\kappa} > \hat{e}^{**} + \hat{r}^{**}$, then it would sell more energy and/or reserves than the optimal two-tuple $(\hat{e}^{**},\hat{r}^{**})$. Hence, whenever (5) holds the strategic seller offers a total capacity of exactly $\hat{e}^{**} + \hat{r}^{**}$. Therefore,

$$\kappa = \begin{cases} \displaystyle\sum_{\substack{i:s^i \text{ not the} \\ \text{strategic seller}}} \alpha^i + \hat{e}^{**} + \hat{r}^{**} & \text{if (5) holds} \\ \displaystyle\sum_i \alpha^i & \text{otherwise,} \end{cases} \qquad (6)$$

where α^i is seller s^i's available capacity. Thus, the conditions under which seller $\hat{s}$ exercises physical withholding [14] are (5) and

$$\hat{e}^{**} + \hat{r}^{**} < \hat{\alpha} . \qquad (7)$$

Clearly, if $\bar{\bar{\rho}}_e = \bar{\rho}_e$ and $\bar{\bar{\rho}}_r = \bar{\rho}_r$, then (5) cannot hold and so there would be no physical withholding.

B. The H-hour period modeling

We represent the system's total demand in the H-hour period by the r.v. $\underset{\sim}{L}$, where $\underset{\sim}{L} = \underset{\sim}{L}_h$ when the system is in hour h. The *peak load* ℓ^p is defined as the maximum value $\underset{\sim}{L}$ may attain during the H-hour period,

$$\ell^p \triangleq \max_{1 \leq h \leq H} \left\{ \ell : p_h(\ell) > 0 \right\}. \qquad (8)$$

[2] Thus, we capture the impacts of the strategic behavior on reliability while avoiding the need of an equilibrium model, e.g., Nash equilibrium, and the complications they bring, e.g., existence of multiple equilibria. In most electricity markets there is more than one strategic seller. However, there are examples of electricity markets dominated by a single seller, such as some European markets [4].

[3] The *SSP* is a nonlinear optimization problem with a discontinuous objective function and a complex feasible set due to the energy and reserves sold. Its efficient solution has yet to be studied, and so we use an exhaustive search for its solution.

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 $\underset{\sim}{A}{}_j^i$,

$$\underset{\sim}{A}{}_j^i = \begin{cases} g_j^i & \textit{with probability } a_j^i \\ 0 & \textit{with probability } \left(1-a_j^i\right). \end{cases} \quad (9)$$

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 available capacity of seller s^i is denoted by the r.v. $\underset{\sim}{A}{}^i = \sum_j \underset{\sim}{A}{}_j^i$ and the system available capacity is denoted by the r.v.

$$\underset{\sim}{A} = \sum_i \underset{\sim}{A}{}^i . \quad (10)$$

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, the realization of these r.v.s are

$$\underset{\sim}{K} = \kappa_h , \quad (11)$$

and

$$\underset{\sim}{C} = \rho_e^* \sum_{\ell : p_h(\ell)>0} p_h(\ell)\, min\left\{\ell, \sum_i \left(e_h^{i*} + r_h^{i*}\right)\right\} + \rho_r^* \sum_i r_h^{i*} , \quad (12)$$

obtained from (6) and from (1), respectively. The first term in (12) are the expected costs of energy. Since every offer in the ERM represents physical capacity,

$$\boldsymbol{P}\left\{\underset{\sim}{K} \le \underset{\sim}{A}\right\} = 1 . \quad (13)$$

Due to physical withholding, $\underset{\sim}{K}$ need not be equal to $\underset{\sim}{A}$. Indeed, $\underset{\sim}{K} < \underset{\sim}{A}$ if and only if there is physical withholding.

We assess the system reliability in the H-hour period with the usual metrics used in reliability analysis [16]:

(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 [23] is used in the assessment of the economic impacts. We explicitly distinguish the metrics from their values by using the notation $LOLP$, $\mathscr{U}$, and $\mathscr{C}_o$, respectively, for their values.

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:

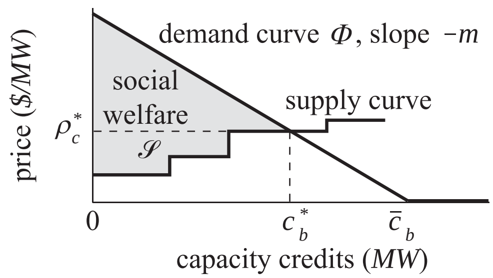

Fig. 2. Social welfare maximization in the CCM.

$$LOLP^M = \boldsymbol{P}\left\{\underset{\sim}{L} > \underset{\sim}{K}\right\}, \quad (14)$$

$$\mathscr{U}^M = H \cdot \boldsymbol{E}\left\{\underset{\sim}{L} - \underset{\sim}{K} \,\middle|\, \underset{\sim}{L} > \underset{\sim}{K}\right\} \cdot \boldsymbol{P}\left\{\underset{\sim}{L} > \underset{\sim}{K}\right\}, \quad (15)$$

$$\mathscr{C}_o^M = w \cdot H \cdot \boldsymbol{E}\left\{\underset{\sim}{L} - \underset{\sim}{K} \,\middle|\, \underset{\sim}{L} > \underset{\sim}{K}\right\} \cdot \boldsymbol{P}\left\{\underset{\sim}{L} > \underset{\sim}{K}\right\}. \quad (16)$$

Due to (13), $LOLP$, $\mathscr{U}$, 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

$$\mathscr{C}_s \triangleq H \cdot \boldsymbol{E}\left\{\underset{\sim}{C}\right\}, \quad (17)$$

and provide a measure of the sellers' revenues and the LSEs' payments in the H-hour period.

C. *The capacity credits market modeling*

The CCM covers the capacity needs for each hour in the H-hour period. Let $\Theta^i(c)$ be the integral over $[0,c]$ of the seller s^i marginal offer price to the CCM, $\xi^i \le g^i$ be the amount of capacity credits offered in the CCM, and c^i be the amount sold by seller s^i. We construct the vectors $\underline{\boldsymbol{\xi}}$ and $\underline{\boldsymbol{c}}$, 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 approximate social welfare $\mathscr{S}\left(\underline{\boldsymbol{c}}, c_b\right)$ while ensuring that the supply-demand balance is satisfied. Consequently, the CCM entails the solution of the following optimization problem:

$$\left.\begin{array}{l} \underset{\underline{\boldsymbol{c}}, c_b}{max}\, \mathscr{S}\left(\underline{\boldsymbol{c}}, c_b\right) = \displaystyle\int_0^{c_b} \Phi(y)\, dy - \sum_{i=1}^{S} \Theta^i\left(c^i\right) \\ s.t. \\ \qquad \underline{\boldsymbol{1}}'\, \underline{\boldsymbol{c}} = c_b \quad \leftrightarrow \quad \rho_c \\ \qquad \underline{\boldsymbol{c}} \le \underline{\boldsymbol{\xi}} \\ \qquad \underline{\boldsymbol{c}}, c_b \ge \underline{\boldsymbol{0}} \end{array}\right\} \; CCMP \quad (18)$$

If sellers submit piecewise linear offers and the capacity credits demand curve is piecewise linear, as in the examples to follow, the *CCMP* is a quadratic program. The optimal solution $\left(\underline{\boldsymbol{c}}^*, c_b^*\right)$ of (18) 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 social welfare maximization is illustrated in Fig. 2 for a piecewise linear demand curve and piecewise constant offers. The capacity credits payments $\mathcal{P}_c$ made by the single buyer are

$$\mathcal{P}_c = \rho_c^* c_b^* . \quad (19)$$

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.

A price taker optimizes its offering strategy by offering all its capacity at marginal costs [17, p. 80], [22]. 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 profit from those foregone opportunities without resorting to capacity withholding. To construct his offer for the CCM, the strategic seller follows a process similar to that for the ERM. The residual demand is determined, the optimal quantity to be sold is chosen, and an offer that attains the optimal sale amount is formulated. 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 offer price caps.

In the next section we analyze the economic and reliability impacts of the proposed program design in the *H*-hour period. Also, we discuss some insights we obtain from a simple implementation of the program.

IV. Program Analysis

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

$$\breve{\Pi}(\hat{e},\hat{r},\hat{c},\hat{\kappa}) \triangleq \hat{\Pi}(\hat{e},\hat{r}) - \Psi(\hat{c},\hat{\kappa}) . \quad (20)$$

Whenever seller $\hat{s}$ provides capacity credits, his net expected profits are maximized by selecting $(\hat{e},\hat{r},\hat{\kappa})$ with the profits in (20), replacing $\hat{\Pi}(\cdot,\cdot)$ in (3). Note that if the strategic seller sells capacity credits, his profits depend explicitly on $\hat{\kappa}$. Moreover, the larger the penalty, the stronger this dependence is. If $\hat{c}$ is equal to seller $\hat{s}$'s available capacity, any amount of capacity withholding entails a penalty, thus the disincentives to withhold are explicit. We analyze the change $\Delta\hat{\kappa}$ in $\hat{\kappa}$ corresponding to a change $\Delta\hat{c} > 0$ in the capacity credits provided by seller $\hat{s}$. When the optimal solution of (3) satisfies the conditions in (5), i.e., when there is physical withholding, the presence of the penalty term ensures that $\Delta\hat{\kappa} \geq 0$. However, when the conditions in (5) do not hold, physical withholding is not profitable, and so the change $\Delta\hat{c} > 0$ may not impact $\hat{\kappa}$. 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 now turn to the evaluation of reliability effects, and for that purpose we compare the reliability evaluation with and without the proposed program. We can prove the following results:

Result 1*: The reliability with the proposed program is at least as good as the reliability without the program.*■

This is a consequence of the fact that increasing the CCM purchases does not reduce the capacity offered in the ERM, which is the one used to evaluate the metrics (14) – (16) .

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 reliability improvements:

Result 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*

$$\boldsymbol{P}\left\{\left\{\underset{\sim}{K}_0 < \underset{\sim}{L}\right\} \cap \left\{\underset{\sim}{K}_0 < c_b^* \leq \underset{\sim}{A}\right\}\right\} > 0 \quad (21)$$

or

$$\boldsymbol{P}\left\{\left\{\underset{\sim}{K}_0 < \underset{\sim}{L}\right\} \cap \left\{\underset{\sim}{K}_0 < \underset{\sim}{A} < c_b^*\right\}\right\} > 0 , \quad (22)$$

then, the proposed program results in an 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 there is an improvement in reliability.

To ensure a reliability improvement, the reliability metrics

TABLE I
DATA FOR THE TWO TEST SYSTEMS

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*)	90	90

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

test system	*A*	*B*
ρ_c^* (*$/MW*)	720	1440
c_b^* (*MW*)	1630	17800
$\mathcal{P}_c$ ($)	1.17 million	25.63 million

TABLE III
VALUES OF THE RELIABILITY METRICS FOR THE TWO TEST SYSTEMS

test system	*A*	*B*
$LOLP^M$	0.0066	0.00135 ± 0.09%
$\mathcal{U}^M$ (*MWh*)	731	128 ± 0.11%
$\mathcal{C}_o^M$ ($)	0.7 million	16 million ± 0.11%
$\mathcal{C}_s$ ($)	56.8 million	319 million ± 0.19%
$\mathcal{C}_s + \mathcal{C}_o^M + \mathcal{P}_c$ ($)	58.7 million	361 million ± 0.30%

TABLE IV
REFERENCE CASE VALUES OF THE METRICS FOR THE TWO TEST SYSTEMS

	test system	*A*		*B*	
	case	no program	no withholding	no program	no withholding
value of metrics	$LOLP^M$	1.34 (10^{-2})	0.34 (10^{-2})	2.70 (10^{-3}) ±1.41%	0.06 (10^{-3}) ±0.25%
	$\mathcal{U}^M$ (*MWh*)	1.47 (10^{3})	0.31 (10^{3})	3.55 (10^{2}) ±1.36%	0.15 (10^{2}) ±0.35%
	$\mathcal{C}_s$ ($)	5.76 (10^{7})	5.56 (10^{7})	3.20 (10^{8}) ±0.19%	3.18 (10^{8}) ±0.12%
	$\mathcal{C}_s + \mathcal{C}_o^M$ ($)	5.91 (10^{7})	5.59 (10^{7})	3.57 (10^{8}) ±1.55%	3.19 (10^{8}) ±0.54%

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

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

Under perfect compliance, the result states that there is no reason to buy more capacity credits than the peak load. The proofs of the three results are given in [15].

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

$$\Phi\left(c_b\right) = max\left\{\bar{c}_b - c_b, 0\right\} \cdot m, \quad c_b \geq 0, \tag{23}$$

and is shown in Fig. 2. The strictly negative slope represents the decreasing marginal value of the capacity credits and makes capacity prices more stable and predictable [24]. In practical implementations, there is a level $\bar{c}_b$ of capacity credits above which reliability cannot improve. From Result 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, we set $\bar{c}_b$ equal to ℓ^p in this simple implementation.

The implementation uses a fixed penalty coefficient $v > 0$ *$/MW*, and so the penalty function $\Psi(\cdot,\cdot)$ is stated as

$$\Psi\left(c^i, \kappa^i\right) = max\left\{c^i - \kappa^i, 0\right\} \cdot v. \tag{24}$$

The simple penalty function in (24) 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 vc^i. The choice of *v* is very important, and we can guarantee perfect compliance by setting

$$v = \bar{v} \triangleq max\left\{\bar{\bar{\rho}}_e - \bar{\rho}_e, \bar{\bar{\rho}}_r - \bar{\rho}_r\right\} \cdot \max_{1 \leq i \leq S}\left\{\frac{g^i}{1MW}\right\}. \tag{25}$$

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 $\mathcal{P}_c$ 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 (25) implies that as the g^is are reduced, $\bar{v}$ is reduced. Moreover, since $\bar{v}$ is a direct function of the 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 simulations we carried out of this simple implementation of the proposed program.

V. SIMULATION STUDY RESULTS

We use the results of simulation studies on two test systems to illustrate the effectiveness of the program to improve reliability. We provide a summary of the data for the test systems in Table I. The two test systems are characterized by different resource mixes and distinct fractions in the strategic seller's market shares. The rest of the data for the two test systems and a presentation of the extensive simulation results are provided in [15].

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

$H = 720$ hours, $v = 10$ $/MW, $m = 40$ $/MW^2, and $\overline{c}_b = 1650$ MW for test system A, and $v = 20$ $/MW, $m = 50$ $/MW^2, and $\overline{c}_b = 17800$ MW for test system B. We assume that each price taker offers capacity credits at the upper bound[4] for the expected costs, $vH\left(1-a_j^i\right)$ $/MW. We further assume that the strategic seller can trade his commitments in the secondary markets at 0 $/MW as long as the price takers have more available capacity than the credits they sold, and that the price takers trade their commitment at the penalty price with the strategic seller whenever the price takers do not have the necessary available capacity. The CCM market clearing results are shown in Table II. The capacity credits price is set by generators with the same availability in the two test systems ($a = 0.9$). As the penalty in test system B is double that in system A, the system B market price is double of the system A market price. Our results indicate that it is not in the strategic seller's interest to exercise market power in the CCM. As such, all CCM sellers behave as price takers. We also performed studies of the impacts of changes in the demand curve parameters m and $\overline{c}_b$. The results show that the players behave as price takers as long as $\overline{c}_b$ is low enough ($\overline{c}_b = \ell^p$ was appropriate in all cases) and as long as there is a relatively high price-dependence in the CCM demand curve (m is low enough, $m = 20$$/MW^2 was appropriate in all cases) [15]. The limits on $\overline{c}_b$ and m depend primarily on the resource mix and the strategic seller market share.

The values of the reliability metrics presented in Table III are computed 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 [25], [26] in light of the large number of generators, and so the reliability metric values have the associated errors given in the table. In Table IV, we measure the improvements due to the proposed program by providing the values of the metrics obtained with no program and with no withholding. We note that there are reliability improvements in both test systems. We examine a representative example of an hour in which the strategic seller decreases the exercise of physical capacity with the program. In this hour, the demand can take the values of 1,350 and 1,500 MWh, the strategic seller has 650 MW of available capacity, and the price takers have a total of 950 MW. Thus, the available capacity exceeds the peak hourly load. It turns out that not selling reserves is the optimal solution for the strategic seller, i.e., $\hat{r}^{**} = 0$. We plot the energy price as a function of the energy sold by the strategic seller in Fig. 3. When the strategic seller sells less than 400 MWh, there is energy shortage and the energy price equals the price cap of 150 $/MWh. When the strategic seller sells between 401 MWh and 550 MWh, there is reserves shortage, the price equals to the offer price of the strategic seller, 90 $/MWh. When the strategic seller sells more than 550 MWh,

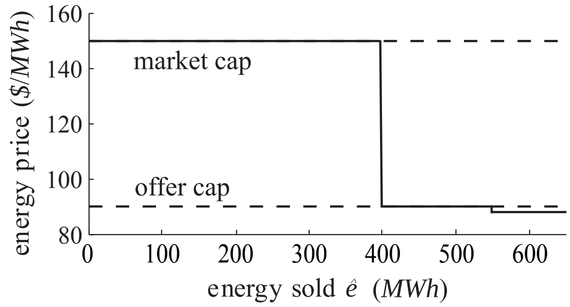

Fig. 3. Energy price as a function of the energy sold by the strategic seller with no reserves sales.

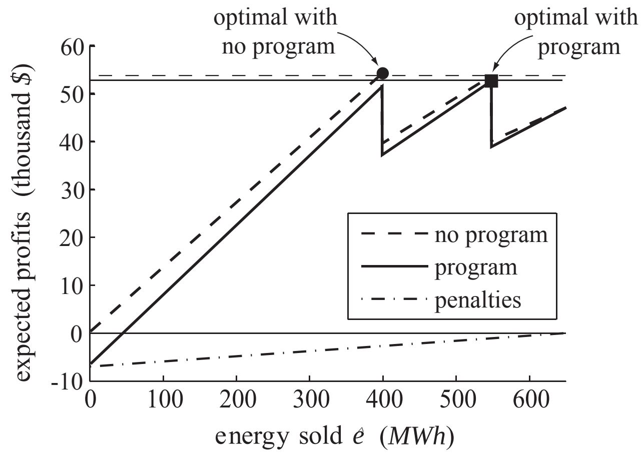

Fig. 4. Impacts of proposed program on the strategic seller's profits.

there is no shortage and the price equals the offer price of the most expensive price taking generator available, 88 $/MWh.

We discuss the nonlinear behavior of the energy price and resulting profits by examining first the case without the program. The price reduction at just over $\hat{e} = 400$ translates into a profit reduction, as shown in Fig. 4, and the solution of (3) gives $\hat{e}^{**} = 400$ MWh. The prices are at the market caps, $\hat{\rho}_e(\hat{e}^{**},\hat{r}^{**}) = \overline{\overline{\rho}}_e$ and $\hat{\rho}_r(\hat{e}^{**},\hat{r}^{**}) = \overline{\overline{\rho}}_r$, and so, by (6), the strategic seller will withhold capacity. Otherwise, suppose that the strategic seller does not withhold, i.e., it offers 650 MWh in the market, none of which is offered to provide reserves. Then, there is no shortage and the energy price is 88 $/MWh. The strategic seller sells 650 MWh of energy, and its profits are smaller than in the case with physical withholding, as shown in Fig. 4. Due to physical withholding, the loss of load probability for the hour is equal to the probability of the load being 1,500 MWh, which is greater than zero, even though there is enough available capacity to supply all the demand.

Consider the case with the program. Since the available capacity is smaller than the capacity credits purchases (1600 < 1630), by our assumptions each available MW provides capacity credits during that hour. Thus, the strategic seller would pay 10 $/MW withheld. The only way to attain sales smaller than the available capacity is by withholding. Hence, if one takes into account the penalties in the expected profits ((20) and Fig. 4), the profits decrease for all amounts of energy sales except for the case with no withholding. Moreover, the solution of (3) considering the penalties gives

[4] This is a worst-case scenario that gives upper bounds for the capacity credits price and payments, and the reliability and economic metrics values. In general, the metrics values would be substantially lower than those in Tables II and III.

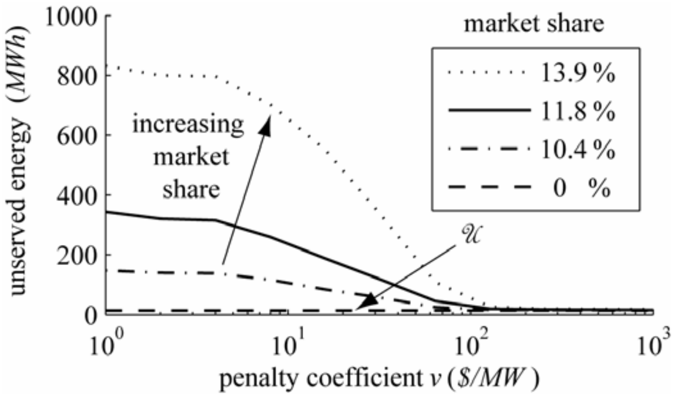

Fig. 5. Unserved energy of test system *B* as a function of the penalty coefficient and the market share of the strategic seller.

$\hat{e}^{**} = 550\,MWh$. Thus, the strategic seller reduces the capacity withheld and the loss of load probability for this hour is 0.

The reliability improvements in both test systems are significant, although the systems are still less reliable than in no withholding case. Sensitivities studies indicate a further reliability improvement if the penalty coefficient is increased, as shown in Fig. 5. Adjusting the m and $\overline{c}_b$ parameters may also bring some improvements in reliability. However, the improvements are less than those attained by increasing the penalty coefficient [15].

The supply costs $\mathscr{C}_s$ are reduced with the program in both test systems. Such reductions are explained considering Figs. 3 and 4. Whenever the strategic seller increases his offer quantities by not withholding, the prices are reduced, from the market cap to the offer cap. The resulting supply costs reductions are not as significant as the reliability improvements, however, because the difference between the offer caps and the market caps is not very large in the examples, the number of hours when physical withholding is profitable is small, and whenever physical withholding is reduced the cleared quantities increase. The total system costs $\left(\mathscr{C}_o^M + \mathscr{C}_s + \mathscr{P}_c\right)$ are a more representative economic metric. They decrease 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 the presence of a higher penalty coefficient results in the opposite effect.

The expected ERM profits of the strategic seller in system *A* with and without the program are *$ million* 12.55 and 12.58, respectively. The decrease in ERM profits is more than compensated by the CCM revenues, which total *$ million* 0.5. Thus, the strategic seller receives payments to decrease the exercise of physical withholding.

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. 5. 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.

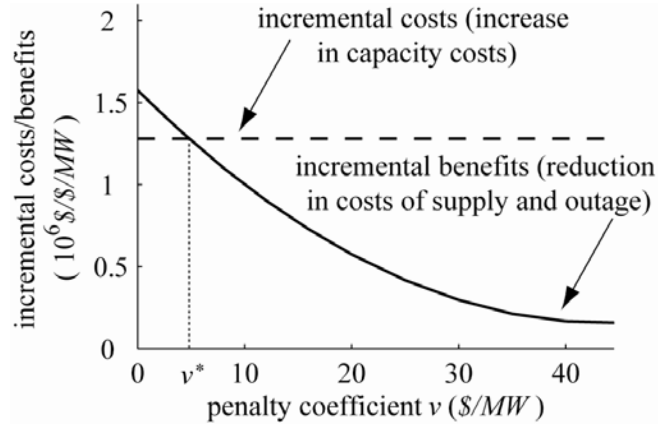

Fig. 6. Incremental costs and benefits in test system *B* with respect to a change in the penalty, as a function of the penalty coefficient.

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 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. 5. 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 *v* increases, $\mathscr{C}_s$ decreases since the exercise of physical capacity withholding is reduced. 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 tune the penalty coefficient for given values of $\overline{c}_b$ and *m*, with the objective of minimizing the total costs $\left(\mathscr{C}_o^M + \mathscr{C}_s + \mathscr{P}_c\right)$. We discuss the results using test system *B*, whose total costs are higher with the program if $v = 20$ *$/MW*. 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. 6. 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 $\overline{c}_b$. Hence, the program can decrease the total costs when the tunable program parameters are appropriately selected.

VI. Summary and Further Work

We have discussed short-term resource adequacy design and analysis in a market environment. We have presented a design of a short-term resource adequacy program that gives explicit incentives for providing capacity to markets and metes out penalties for non-performance situations. 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 incorporate 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 account for the benefits capacity provides to the system, *(ii)* effective penalty schemes that provide the desired incentives for 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 effective mitigation schemes to discourage/ prevent them, whenever applicable. In particular, we will investigate the impacts of double price caps in the optimization of the tunable parameters, so as to gain insights into the relationship between 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.

VII. Appendix I: Nomenclature

r.v. : random variable
h : hour index
H : time horizon, in hours
$\underset{\sim}{L}$: total load for an unspecified hour, r.v.
$\underset{\sim}{L}_h$: total load for the specified hour *h*, r.v.
$p_h(\cdot)$: probability mass function of $\underset{\sim}{L}_h$
ℓ_h : load forecast for hour *h*
ℓ^p : peak load in the *H*-hour period
β_h : reserve requirement for hour *h*
s^i : *i*-th seller
$\hat{s}$: strategic seller
$\hat{}$: denotes a strategic seller's parameter or variable
S : number of selling firms
a^i_j : availability of generator *j* of s^i, $\in [0,1]$
$\underset{\sim}{A}^i_j$: available capacity of generator *j* of s^i, r.v.
$\underset{\sim}{A}^i$: available capacity of s^i, r.v.
α^i_h : realization of $\underset{\sim}{A}^i$ in hour *h*.
$\underset{\sim}{A}$: available system capacity, r.v.
g^i_j : installed capacity of generator *j* of s^i
g^i : installed capacity of s^i
$\underset{\sim}{K}$: total day-ahead offered capacity, r.v.
κ : realization of $\underset{\sim}{K}$, r.v.
κ^i : capacity offered by seller s^i
$\underline{\boldsymbol{\sigma}}_h, \underline{\boldsymbol{\varsigma}}_h$: vectors of energy and reserve offer prices
$\underline{\boldsymbol{\kappa}}_h, \underline{\boldsymbol{\mu}}_h$: vectors of energy and reserve offer quantities
$\underline{\boldsymbol{e}}_h, \underline{\boldsymbol{r}}_h$: vectors of energy and reserve sale quantities
(e^i, r^i) : energy and reserves sales of seller s^i
$\rho^i_e(\cdot,\cdot)$: energy residual demand function faced by s^i
$\rho^i_r(\cdot,\cdot)$: reserves residual demand function faced by s^i
$\Pi^i(\cdot,\cdot)$: day-ahead expected profits for s^i
$\breve{\Pi}^i(\cdot,\cdot)$: expected profits with the program for s^i
$\mathbb{F}^i$: set of feasible sales by s^i
$\bar{\rho}_e$: offer price cap for energy
$\bar{\rho}_r$: offer price cap for reserves
$\bar{\bar{\rho}}_e$: market price cap for energy
$\bar{\bar{\rho}}_r$: market price cap for reserves
ρ^*_e : energy market price
ρ^*_r : reserves market price
ρ^*_c : capacity market price
w : value of lost load
$\underset{\sim}{C}$: day-ahead market costs, r.v.
$\mathscr{C}_s$: supply costs in the *H*-hour period
$\Theta^i(\cdot)$: capacity credits offer of s^i
ξ^i : capacity credits offered by s^i
c^i : capacity credits provided by s^i
$\underline{\boldsymbol{\xi}}$, $\underline{\boldsymbol{c}}$: vectors of capacity credits offered and provided
$\Phi(\cdot)$: capacity credits demand curve
$-m$: slope of the capacity credits demand curve
c_b : capacity credits purchased
$\bar{c}_b$: maximum c_b
$\mathscr{S}(\cdot,\cdot)$: social welfare in the capacity market
$\mathscr{P}_c$: costs of capacity credits incurred by the IGO
$\Psi(\cdot,\cdot)$: penalty function for capacity credit sellers
v : penalty per unit of capacity noncompliance
$\bar{v}$: maximum v
$LOLP$: loss of load probability
$\mathscr{U}$: expected unserved energy
$\mathscr{C}_o$: expected outage costs

Appendix II: Strategic Seller Modeling

Let the market prices be explicit functions of the strategic seller's energy and reserves sales $\hat{e}$ and $\hat{r}$, respectively:

$$\rho_e^* = \hat{\rho}_e(\hat{e},\hat{r}) \quad \text{and} \quad \rho_r^* = \hat{\rho}_r(\hat{e},\hat{r}) . \qquad (26)$$

These are the *residual demand* functions for the strategic seller, and take into account the optimality conditions of (1).

The two-tuple $(\hat{e},\hat{r})$ is attainable if and only if there exists an offer that lets seller $\hat{s}$ sell $\hat{e}$ *MWh* and $\hat{r}$ *MW*. We show in [15] that a two-tuple $(\hat{e},\hat{r})$ is attainable if and only if:

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

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

$$\hat{\mathbb{F}} \triangleq \left\{ \begin{matrix} (\hat{e},\hat{r}) \geq 0 : \hat{e} + \hat{r} \leq \hat{\alpha}, \\ \hat{r}\left[\hat{\rho}_e(\hat{e},\hat{r}) - \overline{\rho}_e\right] \leq \hat{r}\,\hat{\rho}_r(\hat{e},\hat{r}) \end{matrix} \right\}. \qquad (27)$$

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. Neglecting the reserves costs, and assuming that the reserves provided by seller $\hat{s}$ are used first, the expected profits of seller $\hat{s}$ are

$$\begin{aligned} \hat{\Pi}(\hat{e},\hat{r}) = \sum_{\ell : p(\ell) > 0} & p(\ell)\Big[\hat{\rho}_e(\hat{e},\hat{r})\left(\hat{e} + min\{\ell,\hat{r}\}\right) \\ & - \hat{\chi}_e\left(\hat{e} + min\{\ell,\hat{r}\}\right)\Big] + \hat{\rho}_r(\hat{e},\hat{r})\,\hat{r}. \end{aligned} \qquad (28)$$

where $\hat{\chi}_e(\cdot)$ is the energy production costs function.

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