Quantification of Market Performance as a Function of System Security

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***Abstract*—The tight coupling between market and system operations in the restructured environment requires a thorough understanding of the interdependence between the market performance and the way the power systems are operated. In particular, we need to go beyond the qualitative characterization and to quantify the dependence of the market performance on the system security. Such studies are typically not performed in today's regional transmission organization, or *RTO*, structures. In this paper, we develop a general approach to quantify the monetary impacts of complying with a specified security criterion when the deployment of appropriate preventive and/or corrective security control actions is fully taken into account. This approach is deployed in the day-ahead electricity markets and is based on the emulation of the way the *RTO* currently operates the market and the grid, the latter in compliance with the security criterion. The proposed approach has a wide range of applications such as comparative market performance assessments of different security criteria and the cost/benefit analysis of network improvements to mitigate the market performance impacts of a set of specified contingencies. We illustrate the application of the proposed approach on the large-scale ISO-NE system to quantify the monetary impacts associated with changing from the current security criterion to two other criteria using the actual 2005 day-ahead data—the historical system model and the bids/offers submitted—with the actual market clearing methodology. These studies capture, in a meaningful way, the impacts of the changes with respect to the current security criterion. An important finding of this study is that the economic efficiency of electricity markets need not decrease when the system is operated under a stricter criterion.**

***Index Terms*—Corrective and preventive security control actions, electricity market economics, locational marginal price, price-responsive demand, power system security, $(n-1)$ and $(n-2)$ security, social welfare maximization.**

I. Introduction

In the restructured environment, the improvement of the economic efficiency of electricity markets has been the focus of recent efforts [1], [2]. Central to these efforts is the better understanding of the nature of the tight coupling between market and system operations. An important aspect of this coupling is the dependence of the market outcomes on the way the system is operated. A key driver in system operations is the security criterion, with which compliance must be ensured. The focus of this work is the dependence of market performance on system security. In this paper, we propose an approach to quantify the market performance as a function of a specified security criterion. We illustrate the application of the proposed approach on a large-scale system.

System security is defined as the ability of the interconnected system to provide electricity with the appropriate quality under normal and contingency conditions [3]. The security criterion, with which the power system operations must comply, consists of the set of postulated contingencies and the associated preventive and/or corrective control actions [4]. For a given operating state, security assessment entails the verification that no violation occurs for any of the postulated contingencies taking fully into account the deployment of the associated security control actions. As these actions affect the market outcomes, a key step in the efforts to improve market performance is the assessment of these impacts of complying with the security criterion in monetary terms. Such studies are, typically, not performed by today's large regional transmission organizations, or *RTO*s. Consequently, there is a need for an appropriate methodology to quantitatively measure the market performance impacts of complying with security criterion.

The economic efficiency of electricity markets is analyzed in various contexts by both empirical and analytical means. The empirical studies investigate the adverse impacts of market participants' behaviors on the performance of electricity markets [5]–[8]. The analytical studies, on the other hand, focus on the impacts of constrained system operations on markets to determine the unavoidable losses in the economic efficiency of electricity markets [9], [10]. The interactions between the system security criterion and the associated economics are investigated in terms of the marginal costing—used to determine the security prices—and the evaluation of expected system security costs. The security prices, determined in this way, explicitly incorporate the willingness of the market participants to provide security control capability into the market clearing process [11]–[13]. The expected system security costs are evaluated taking explicitly into account the random nature of the outages and the costs of the required security control actions to deal with them [14], [15]. A key result of [15] is that the security criterion may be set by the cost/benefit analysis taking into account the expected costs of operating the system and the expected outage costs. Such an approach may be viewed as the application of the notion of "value of reliability" introduced in [16] which was used for operational planning purposes [17].

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There is a clear need, in the restructured environment, to quantify the market performance as a function of system security in a way that appropriately reflects the *RTO* operations. This quantification further requires the consideration of different market and system conditions that may exist within a period in order to capture the range of impacts under such conditions.

In this work, we explicitly consider the market and the system operations from the point of view of the *RTO*s. We consider the day-ahead market, or *DAM*, structure. *RTO*s use uniform price auctions for clearing the *DAM*s and also provide transmission services to the bilateral transactions [18]. In the proposed approach, we quantify the market performance for a system snapshot under a specified security criterion. This quantification, based on the emulation of the way the *RTO* currently operates the markets and the system for a specified point of time, serves as the basic building block of the methodology. The evaluation of the impacts over a longer period requires an extension of the snapshot analysis. In this way, we are able to capture the impacts of changes in the topology of the system, the network parameters, the set of generating resources, and the market participants' behaviors over time. We repeat this procedure to study the corresponding impacts of a different criterion, so that we can carry out comparative market performance assessments. Such assessments provide the measures of the monetary and resource dispatch impacts of a change in security criterion.

The proposed approach has a wide range of applications such as the justification by the *RTO* of the decision to modify the security criterion to be used and the cost/benefit analysis of network improvements to mitigate the market performance impacts of a set of specified contingencies. We illustrate the application of the proposed approach on the ISO-NE *DAM* to quantify the performance impacts of operating the system under different system security criteria for representative days in 2005 period. For this study, we use the historical day-ahead data—the system model and the bids/offers submitted—with the actual market clearing methodology. These studies capture, in a meaningful way, the impacts of the changes with respect to the current security criterion. An important characteristic of the study period is the role of price-responsive demand in ensuring compliance with the system security criterion. We evaluate explicitly the impacts of such demand has on market outcomes. An important finding of this study is that the economic efficiency of electricity markets need not decrease when the power systems are operated under a stricter criterion when price-responsive demand is present and appropriate control actions are effectively deployed.

This paper contains five additional sections. The nature of the problem and the market performance quantification for a system snapshot are described in Section II. We devote Section III to the discussion of the proposed approach. In Section IV, we apply the proposed approach to the ISO-NE *DAM* and present the study results in detail. Section V summarizes the paper and discusses future work. We have two appendices in which we provide the notation used in the paper and the scheme used for the selection of representative days within a specified month.

II. Market Assessment for a System Snapshot

We introduce specific assumptions on unit commitment decisions, ancillary services, and the market participants' behaviors so as to allow the side-by-side comparison of different security criteria impacts for a given system. We assume that the unit commitment decisions fully reflect the requirements of the security criterion under consideration. In particular, this assumption ensures the feasibility of meeting the system fixed demands under such a criterion. As the focus of this investigation is limited to energy only markets, we assume that the ancillary services provision and acquisition requirements under the *RTO* framework do not impose any additional constraints on the system. For the purposes of this study, we furthermore assume that the bidding behavior of each market participant is independent of the security criterion in force. Since we replicate the *RTO* actions, we ensure compliance with the security criterion in force, but implicitly ignore the probability of any contingency in the studies.

The modeling of the large-scale interconnected system operated by the *RTO* requires the explicit representation of the areas that make up the system as well as the tie lines that interconnect them in market and system operations. We consider a power system network consisting of K interconnected areas denoted by the set $\mathcal{A} \triangleq \{A^k : k = 1, \ldots, K\}$ with each area A^k having a node set $\mathcal{N}^k$ with N^k buses. Each area $A^k \in \mathcal{A}$ is connected to one or more other areas via tie lines. We associate a security criterion $\mathscr{C}$ with a specific contingency list and a specified control action—preventive or corrective—for every contingency on that list. A preventive control action associated with a postulated contingency entails the modification of the pre-contingency—base case—state, to eliminate any potential violation, were that contingency to occur. On the other hand, an associated corrective control action may involve the modification of both the pre- and the post- contingency states. The modification of the pre-contingency state involves steering the operating point into a state in which the *RTO* is able to modify the resources' dispatch, including those of both load and generation, to alter the post-contingency state only after the contingency actually occurs. As such, there may be no change in resource utilization if the contingency fails to happen. For some contingencies, such as a generator outage or a sudden load change, the *RTO* may take only corrective control actions.

The *RTO* decision making problem for a given snapshot of the system under a specified security criterion takes explicitly into account the multi-area structure and the constraints imposed by the tie line limits. We next express the statement of the problem solved by the *RTO* for a given snapshot of the interconnected system in mathematical terms.

While the interconnected system has a single market operated by the *RTO*, the presence of network and physical constraints necessitate that we consider the market players in each area separately. We assume without loss of generality, that at each bus $i \in \mathcal{N}^k$ there is a single seller and a single buyer. We denote by the sets $\mathscr{S}^k = \{s_1^k, \ldots, s_{N^k}^k\}$ and $\mathscr{B}^k = \{b_1^k, \ldots, b_{N^k}^k\}$, the collection of sellers and that of buyers of the area $A^k \in \mathcal{A}$, respectively. Each seller (buyer) submits price and quantity offer (bid) function indicating the willingness to sell (buy) the amount of energy to (from) the *RTO*. Bilateral transactions coexist with the *RTO* market operations. We represent a bilateral transaction ω_w, whose *from* node is $m_w \in \mathcal{N}^k$ of A^k, *to* node is $n_w \in \mathcal{N}^r$ of A^r, and desired transaction amount is $\bar{t}_w$, by the triplet $\omega_w \triangleq \{m_w, n_w, \bar{t}_w\}$. Here k and r are indices that may represent different areas. The set of bilateral transactions is $\mathcal{W} = \{\omega_1, \ldots, \omega_W\}$. Each transaction submits a willingness to pay function, which states a willingness to pay maximum transmission usage fees for receiving the requested transmission services as a function of the transaction amount delivered [18]. The *RTO* weighs the willingness to pay of the bilateral transactions with that of the individual market participants to determine the amount of transmission service provision to each player. For this purpose for a given snapshot of the system, the *RTO* solves a security constrained OPF, or SCOPF, problem with the objective to maximize the social welfare under the security criterion $\mathscr{C}$ whose contingency index set is denoted by $\mathscr{J}_{\mathscr{C}}$. We state the SCOPF problem as

$$\max \mathcal{S} \triangleq \sum_{k=1}^{K}\left(\sum_{j=1}^{N^k}\beta_{b_j^k}\left(p_{b_j^k}^{(0)}\right) - \sum_{i=1}^{N^k}\beta_{s_i^k}\left(p_{s_i^k}^{(0)}\right)\right) + \sum_{w=1}^{W}\alpha_w\left(t_w^{(0)}\right) \quad (1)$$

subject to

$$\underline{\boldsymbol{g}}^{(0)}\left(\underline{\boldsymbol{p}}_s^{(0)}, \underline{\boldsymbol{p}}_b^{(0)}, \underline{\boldsymbol{t}}^{(0)}, \underline{\boldsymbol{\chi}}^{(0)}, \underline{\boldsymbol{\gamma}}^{(0)}\right) = \underline{\mathbf{0}} \quad \leftrightarrow \quad \underline{\boldsymbol{\lambda}}^{(0)} \quad (2)$$

$$\underline{\boldsymbol{h}}^{(0)}\left(\underline{\boldsymbol{p}}_s^{(0)}, \underline{\boldsymbol{p}}_b^{(0)}, \underline{\boldsymbol{t}}^{(0)}, \underline{\boldsymbol{\chi}}^{(0)}, \underline{\boldsymbol{\gamma}}^{(0)}\right) \leq \underline{\mathbf{0}} \quad \leftrightarrow \quad \underline{\boldsymbol{\mu}}_h^{(0)} \quad (3)$$

and for every $j \in \mathscr{J}_{\mathscr{C}}$

$$\underline{\boldsymbol{g}}^{(j)}\left(\underline{\boldsymbol{p}}_s^{(j)}, \underline{\boldsymbol{p}}_b^{(j)}, \underline{\boldsymbol{t}}^{(j)}, \underline{\boldsymbol{\chi}}^{(j)}, \underline{\boldsymbol{\gamma}}^{(j)}\right) = \underline{\mathbf{0}} \quad \leftrightarrow \quad \underline{\boldsymbol{\lambda}}^{(j)} \quad (4)$$

$$\underline{\boldsymbol{h}}^{(j)}\left(\underline{\boldsymbol{p}}_s^{(j)}, \underline{\boldsymbol{p}}_b^{(j)}, \underline{\boldsymbol{t}}^{(j)}, \underline{\boldsymbol{\chi}}^{(j)}, \underline{\boldsymbol{\gamma}}^{(j)}\right) \leq \underline{\mathbf{0}} \quad \leftrightarrow \quad \underline{\boldsymbol{\mu}}_h^{(j)} \quad (5)$$

$$\left|\underline{\boldsymbol{p}}_s^{(j)} - \underline{\boldsymbol{p}}_s^{(0)}\right| \leq \underline{\Delta \boldsymbol{p}}_s^{(j)} \quad \leftrightarrow \quad \underline{\boldsymbol{\mu}}_s^{(j)} \quad (6)$$

$$\left|\underline{\boldsymbol{p}}_b^{(j)} - \underline{\boldsymbol{p}}_b^{(0)}\right| \leq \underline{\Delta \boldsymbol{p}}_b^{(j)} \quad \leftrightarrow \quad \underline{\boldsymbol{\mu}}_b^{(j)} \quad (7)$$

$$\left|\underline{\boldsymbol{t}}^{(j)} - \underline{\boldsymbol{t}}^{(0)}\right| \leq \underline{\Delta \boldsymbol{t}}^{(j)} \quad \leftrightarrow \quad \underline{\boldsymbol{\mu}}_t^{(j)}. \quad (8)$$

Here, we use the superscript (j) to denote the contingency cases with the base case denoted by *(0)*. The vector associated with the right-hand side of a constraint is the dual variable of that constraint. The relations in (2) and (3) represent the operational constraints for the base case, while those in (4)–(8) represent the operational constraints for the contingency cases. The $|\mathscr{J}_{\mathscr{C}}|+1$ equality constraints in (2) and (4) state the nodal power balance equations for the base case and for each postulated contingency case, respectively. The base case (3) and contingency case (5) inequality constraints state the system components' operational limits, as well as, the so-called generic limitations representing the physical, engineering and policy considerations. The range of the decision variables of the security control action for each contingency $j \in \mathscr{J}_{\mathscr{C}}$ is given in (6)–(8) together with the limiting values of these ranges. The preventive control actions have a zero range in contrast to the corrective actions whose non-zero range reflects the additional flexibility to address the onset of the contingency. Note that, in the SCOPF, we explicitly take into account the costs of modifying the pre–contingency state but ignore any costs related to the post–contingency state modification.

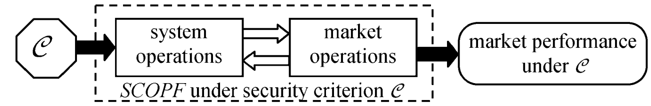

Fig. 1. Snapshot assessment framework.

The market performance under the specified security criterion $\mathscr{C}$ for the snapshot system may be quantified from the market outcomes given by the solution of (1)–(8). We define metrics to measure market outcomes on a system and an area basis, as well as, the impacts on individual player outcomes. We use the optimal value of the social welfare $\mathscr{S}|_{\mathscr{C}}$. under $\mathscr{C}$ as a measure for the economic efficiency of the market as a whole. In addition, for area A^k, we evaluate

$$\mathscr{S}^k\Big|_{\mathscr{C}} \triangleq \sum_{i=1}^{N^k}\left[\beta_{b_i^k}\left(p_{b_i^k}^{*(0)}\right) - \beta_{s_i^k}\left(p_{s_i^k}^{*(0)}\right)\right]\Bigg|_{\mathscr{C}} \quad (9)$$

to determine the area A^k contribution to the social welfare. The *producer* (*consumer*) surplus measures the performance or the gain of each seller (buyer) for participating in the electricity market. The seller s_i^k producer surplus is

$$\sigma^{s_i^k}\Big|_{\mathscr{C}} \triangleq \left[\lambda_i^{*k^{(0)}} p_{s_i^k}^{*(0)} - \beta_{s_i^k}\left(p_{s_i^k}^{*(0)}\right)\right]\Big|_{\mathscr{C}} \quad (10)$$

and the buyer b_i^k consumer surplus is

$$\sigma^{b_i^k}\Big|_{\mathscr{C}} \triangleq \left[\beta_{b_i^k}\left(p_{b_i^k}^{*(0)}\right) - \lambda_i^{*k^{(0)}} p_{b_i^k}^{*(0)}\right]\Big|_{\mathscr{C}}. \quad (11)$$

Here, $\lambda_i^{*k^{(0)}}$ is the locational marginal price (*LMP*) at node i of the area k corresponding to the base case conditions. We use the total dispatched load to evaluate the total cleared demand quantity under criterion $\mathscr{C}$

$$P|_{\mathscr{C}} \triangleq \sum_{k=1}^{K}\sum_{i=1}^{N^k}\left[p_{b_i^k}^{*(0)} + \sum_{w=1, i=n_w \in N^k}^{W} t_w^{*(0)}\right]\Bigg|_{\mathscr{C}}. \quad (12)$$

We compute the area-wide net injection to indicate amount of net power imported into to an area A^k with

$$P^k|_{\mathscr{C}} \triangleq \sum_{i=1}^{N^k}\left[p_{s_i^k}^{*(0)} - p_{b_i^k}^{*(0)} + \sum_{\substack{w=1\\ i=m_w \in N^k}}^{W} t_w^{*(0)} - \sum_{\substack{w=1\\ i=n_w \in N^k}}^{W} t_w^{*(0)}\right]\Bigg|_{\mathscr{C}}. \quad (13)$$

The value of the metrics mentioned above is useful for the performance quantification of market for a given snapshot and constitutes the basic building of the approach. We conceptually represent this snapshot assessment framework in Fig. 1.

When a different security criterion $\mathscr{C}'$ is considered, the *RTO* must solve a modified SCOPF in which the constraints in (4)–(8) reflect the changes in the contingency set $\mathscr{J}_{\mathscr{C}}$ and in the security control actions associated with each contingency. To measure the impacts on market performance due to the change in the security criterion from $\mathscr{C}$ to $\mathscr{C}'$, we introduce for each metric the relative performance metric which measures the difference of the values under $\mathscr{C}'$ and $\mathscr{C}$, respectively. For example, the relative social welfare metric is

$$\Delta \mathscr{S}_{\mathscr{C}'} = \mathscr{S}\Big|_{\mathscr{C}'} - \mathscr{S}\Big|_{\mathscr{C}} \tag{14}$$

and quantifies the change in economic efficiency of the electricity market for the change in the security criterion from $\mathscr{C}$ to $\mathscr{C}'$. We use analogous expressions for the metrics in (9)–(13) to define the corresponding relative performance metrics for such a change. These relative measures have practical and useful interpretations. For example, the relative metric of the contribution to the social welfare of area A^k indicates how the market participants located in A^k are impacted by the change in the security criterion from $\mathscr{C}$ to $\mathscr{C}'$. We interpret in a similar way the changes in the producer/consumer surpluses, the total dispatched load and the area-wide net injection.

The feasibility set under the security criterion $\mathscr{C}$ is determined by the collection of decision variables that satisfy the constraints (2) – (8). We call the security criterion $\mathscr{C}'$ tighter than $\mathscr{C}$ if the feasibility set under $\mathscr{C}'$ is a strict subset of the feasibility set corresponding to the criterion $\mathscr{C}$. It follows that the optimal social welfare under $\mathscr{C}'$ is bounded from above by that under $\mathscr{C}$. The value of the relative social welfare metric is, therefore, non-positive and depends on, among other factors, the willingness to pay of the buyers.

We distinguish between fixed demand buyers and those with price-responsive demand. The fixed demand bid is a special case of the price sensitive bid in which a specified quantity is submitted with no price information. Such a bid indicates an unlimited willingness to pay for the electricity purchases to meet the fixed quantity bid, i.e., the buyer is willing to pay any price to obtain the electricity. There are, however, difficulties in determining the appropriate value of the benefits of the fixed demand buyers. In order to include these buyers' benefits in the SCOPF problem formulation (1) – (8), we use a constant per *MWh* benefit value, τ, for the fixed demand. A change in the security criterion does not impact the such buyers benefits.

Under a given security criterion, the snapshots corresponding to different system and market conditions may result in marked changes in the market performance outcomes. Such differences are caused by many factors including changes in the loads, the set of available units, and the offers/bids submitted. In turn, these changes may also result in different values of the relative performance metrics. Consequently, these assessments must be carried out over a period to correctly capture the impacts of the different conditions that exist during that period. In the next section, we extend the snapshot approach to carry out such assessments.

III. Proposed Approach

In this section, we describe the way we extend the comparative market performance assessment over a study period. Since the focus of this work is on the *DAM*s, we use an hourly resolution as the shortest time unit and represent the system for the hour h by its system snapshot.

Conceptually, we assess the market performance assessment at each hour of a given study period. In effect, we apply the framework shown in Fig. 1 to each hour of the period for the specified security criterion. To assess the market performance impacts due to a change in the security criterion, the entire multiple snapshot procedure must be repeated for the security criterion under consideration. The hourly values of the relative performance metrics are summed to obtain the daily values which, in turn, are used to compute the relative performance metrics for the entire study period. However, for a large-scale system, such an approach may impose a large burden on computing resources. One way to deal with this complication is to perform the assessments for a smaller representative sample of the hours. For this purpose, we require a scheme that systematically selects this smaller subset of representative hours.

A key requirement in selecting these hours is the incorporation of the unit commitment decisions which entail inter-temporal effects across the hours of the commitment. To fully capture the inter-temporal effects, all the hours of the unit commitment period need to be considered. Since, for typical market applications, the unit commitment period is a day, this requirement shifts the selection of representative sample of hours to that of days, since all the hours of such days must be included.

A first step in the selection of representative days is the partitioning of the study period into sub-periods. Since many operational studies are carried out on a monthly basis, we use a month as a sub-period. For a given month i, we determine the subset of representative days and construct the set $\mathscr{D}_r^i$. We choose the elements of $\mathscr{D}_r^i$ on the basis of the daily peak demand values. These values take into account both the fixed demands and the price sensitive quantities bid. We construct the monthly load duration curve, or *LDC*, for the daily peak data. The basic idea in the construction of $\mathscr{D}_r^i$ is to use an approximation of the *LDC* by a curve with fewer levels of load. We construct such an approximation by maintaining the base and the peak load levels, and then selecting k days so that we replace the original *LDC* by at most a ($k+2$) load level approximate *LDC*. We measure the "goodness" of the approximation in terms of an error based on the monthly energy. If the error fails to satisfy a specified tolerance, k is increased until the tolerance check is satisfied. We provide the details of the scheme in Appendix B. We repeat this process for each of the months within the study period and then construct the set of representative days $\mathscr{D}_r$ of the study period by the union of the monthly $\mathscr{D}_r^i$.

We apply the structure shown in Fig. 1 to each hour of the days in $\mathscr{D}_r$ for each specified criteria. We quantify the hourly relative performance metrics and aggregate them for each day. We use the number of days each day in $\mathscr{D}_r^i$ represents and aggregate the daily figures to obtain monthly impacts. The daily figures also serve to evaluate key statistics for each month such as mean, variance and range. The study period impacts then are aggregated form the monthly ones. Thus, we are able to quantify the system and area-wide *MW* as well as dollar impacts on a daily, monthly and period basis.

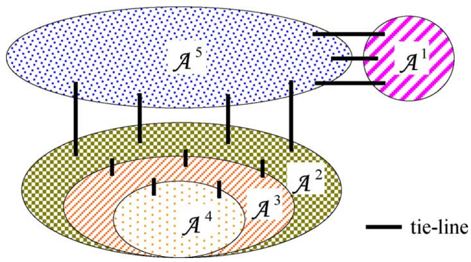

Fig. 2. Multi-area structure of the ISO-NE system.

The proposed approach has a wide range of applications such as the justification by the *RTO* of the decision to modify the security criterion to be used and the cost/benefit analysis of network improvements to mitigate the market performance impacts of a set of specified contingencies. Other applications include the formulation of the control actions for specific contingencies, and the assessment of specific behavioral changes of market participants under various security criteria. We next illustrate an application of the proposed approach to the ISO-NE *DAM* system.

TABLE I
REGIMES $\mathscr{R}_1$ AND $\mathscr{R}_2$ LOAD CHARACTERISTICS

regime	$\mathscr{R}_1$		$\mathscr{R}_2$	
load type	fixed	price sensitive	fixed	price sensitive
minimum demand	6,232	2,944	5,394	5,139
maximum demand	21,292	4,845	12,109	9,573
average	13,075	4,294	8,756	6,964

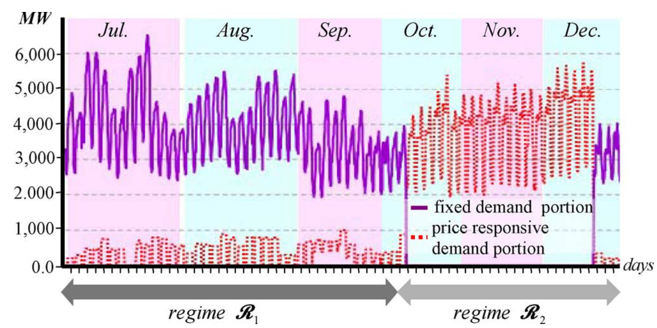

Fig. 3. Bidding behavior change of the larger buying entity.

IV. Application Study

We illustrate the application of the proposed approach on the ISO-NE *DAM*. The objective of this study is to analyze whether the economic efficiency of the ISO-NE *DAM* is adversely impacted by the system operations complying with the security criterion in force. For this purpose, we quantify the market performance as a function of three security criteria and perform comparative assessments. We measure the changes with respect to the outcomes under the current ISO-NE security criterion.

We use the system and market data from the year 2005 and utilize the actual market clearing software used for the ISO-NE *DAM*. We start out with a brief description of the multi-area structure of the ISO-NE system. Then, we discuss the selection of the representative days for the study period. We describe the ISO-NE current security criterion, which we use as the reference criterion, and the two security criteria considered. We then summarize and interpret the study results.

Each area of the ISO-NE system is characterized as either import or export. The import areas are [19]

- A^1 : Boston/NE Massachusetts
- A^2 : Connecticut
- A^3 : SW Connecticut
- A^4 : Norwalk/Stamford.

We treat rest of the system as a single export area and denote it by A^5. Fig. 2 illustrates conceptually the multi-area structure of the ISO-NE. A salient feature is the nested structure of the areas $A^4 \subset A^3 \subset A^2$. From the physical and the economic point of view, the generation of the export area is required to meet the load of the import areas.

The study is performed for the second half of the year 2005. This study period was chosen to allow the use of market and system data that reflects the most up-to-date ISO-NE procedures and rules. The analysis of the load in the selected period shows that the demand levels in the summer months, July and August, are significantly higher than those in the *non-summer* months—the months from September to December. Furthermore, the range of daily peak demands in the summer months is considerably larger than that in the non-summer months. Due to the maintenance scheduling, the sets of available resources in summer months are different than those in the other months. In addition, the ratings of the system components differ in each summer month from those in the other months. The period under study is further characterized by the existence of two distinct regimes $\mathscr{R}_1$ and $\mathscr{R}_2$—pre- and post- October 9, 2005, respectively. The ratio of the hourly price sensitive bid amounts to the total hourly demand changes markedly from a small value under the regime $\mathscr{R}_1$, to a sizable fraction under the regime $\mathscr{R}_2$. The hourly loads in these two regimes are further distinguished in terms of their peak, base and average values. We present the load characteristics of the regimes $\mathscr{R}_1$ and $\mathscr{R}_2$ in Table I. The minimum, maximum and the average hourly load values are disaggregated into the fixed and price responsive components in Table I. The significant increase in the fraction of price-sensitive demand is due to the bidding behavior change of the large buying entity whose demand corresponds to approximately 25% of the total system demand. This buyer submits, on the average, only 10% of his demand as price sensitive under the regime $\mathscr{R}_1$. However, the buyer has no fixed demand under regime $\mathscr{R}_2$ as all of the buyer's bids become price sensitive, as shown in Fig. 3. Due to the size of the buyer's demand, the marked change in his bidding behavior results in a significant portion of the total system demand that is price responsive under the regime $\mathscr{R}_2$.

We select the representative days from each month using the scheme of Appendix B. We construct the *LDC* approximation for each summer and non-summer month by 14 and 10 representative days, respectively. Since these approximations provide acceptably small errors, we determine the elements of each $\mathscr{D}_r^i$ and construct $\mathscr{D}_r$.

TABLE II
TOTAL HOURLY DISPATCHED LOADS AND RANGE OF IMPACTS

metric	regime	range (*MW*)	average (*MW*)
$P_{\mathscr{C}}$	$\mathscr{R}_1$	(9,177 , 25,638)	16,967
	$\mathscr{R}_2$	(8,733 , 23,281)	15,421
$\Delta P_{\mathscr{C}^a}$	$\mathscr{R}_1$	(0 , 452)	141
	$\mathscr{R}_2$	(0 , 273)	42
$\Delta P_{\mathscr{C}^b}$	$\mathscr{R}_1$	(-818 , 0)	-184
	$\mathscr{R}_2$	(-557 , 0)	-128

The ISO-NE operates the system under the security criterion $\mathscr{C}$ whose list of contingencies is

$$\mathscr{J}_{\mathscr{C}} = \mathscr{J}_{n-1} \cup \left(\bigcup_{k=1}^{4} \boldsymbol{\mathcal{M}}^k \right). \tag{15}$$

Here, $\mathscr{J}_{n-1}$ is the set of single element contingencies considered by the ISO-NE and $\boldsymbol{\mathcal{M}}^k$ is the set of double tie line contingencies specified for each import area $A^k \in \boldsymbol{a}, k = 1, \ldots, 4$. Each selected tie line pair interconnects the import area A^k to any other area of the system. The set of control actions for the security criterion consists of preventive control actions which are associated with the elements of $\mathscr{J}_{n-1}$, and corrective control actions which are associated with the double element tie line contingencies of $\cup_{k=1}^{4} \boldsymbol{\mathcal{M}}^k$ [19]. We select the criterion $\mathscr{C}$ as the reference criterion and consider two specific criteria $\mathscr{C}^a$, a modified $(n-1)$ security , and $\mathscr{C}^b$, a modified $(n-2)$ security. For the criterion $\mathscr{C}^a$, the contingency list $\mathscr{J}_{\mathscr{C}^a} = \mathscr{J}_{n-1}$, and preventive control action is the deployed for each contingency in $\mathscr{J}_{\mathscr{C}^a}$. For the criterion $\mathscr{C}^b$, the contingency list $\mathscr{J}_{\mathscr{C}^b} = \mathscr{J}_{\mathscr{C}}$, but we replace the corrective control actions by the preventive control actions for the contingencies in $\cup_{k=1}^{4} \boldsymbol{\mathcal{M}}^k$. We next discuss the market performance impacts of the change of security criterion $\mathscr{C}$ to each of the criteria considered and distinguish those impacts under the two regimes $\mathscr{R}_1$ and $\mathscr{R}_2$.

We first focus on the *MW* impacts. For the reference criterion $\mathscr{C}$, we obtain the range and the average values of the total hourly dispatched load P_C under the regimes $\mathscr{R}_1$ and $\mathscr{R}_2$. We compute the changes from the $P_{\mathscr{C}}$ values under the two security criteria and present the results in Table II. We observe that the price-responsive demand plays an important role in the *DAM*. For each security criterion, the changes under the regime $\mathscr{R}_2$ are considerably lower than those under the regime $\mathscr{R}_1$. In fact, the changes are more pronounced for the change of the security criterion from $\mathscr{C}$ to $\mathscr{C}^b$ than from $\mathscr{C}$ to $\mathscr{C}^a$. We hypothesize that the factors that contribute to these distinct outcomes are due to the structure of the system, the effectiveness of the security control actions and the nature of the constraints imposed on the system operations.

The change from the current security criterion to either of the two criteria studied impacts the value of the system transfer capability. The change in the value of the system transfer capability, in turn, affects the ability of the import areas to bring in energy from the export area. In fact, the analysis of the ISO-NE system during this 2005 study period indicates that the replacement of the security criterion $\mathscr{C}$ by the criterion $\mathscr{C}^a$ results in the increased import capabilities of the import areas for each hour.

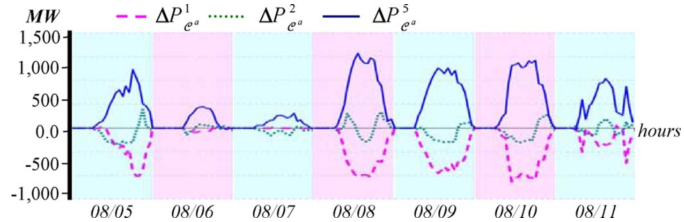

Fig. 4. Area-wide net injection impacts under $\mathscr{C}^a$.

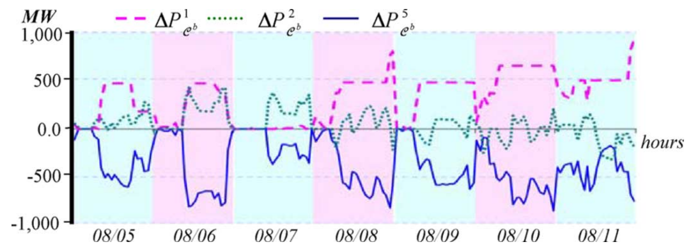

Fig. 5. Area-wide net injection impacts under $\mathscr{C}^b$.

But, the increased capability may not be utilized in every hour. For example, the imports by the stand-alone area A^1 buyers increase their imports from the export area, thereby decreasing their dependence on the less economic A^1 resources. On the other hand, the imports of the nested area A^2, due to the physical constraints of the A^2 network, may not utilize such increased capability in every hour. We measure the changes in the utilization of the increased import capabilities using the relative area-wide net injection metric for the areas A^1, A^2 and A^5. We illustrate the results for the import areas A^1 and A^2, and the export area A^5 for a week in August 2005 in Fig. 4. These plots are typical for the study period, particularly in terms of the more pronounced impacts in the daily peak hours than those in the off-peak hours.

Due to the fact that the system operations under the criterion $\mathscr{C}^b$ are more constraining than those under the criterion $\mathscr{C}$, the security change from $\mathscr{C}$ to $\mathscr{C}^b$ results in the decreased import capabilities of the import areas for every hour of the study period. In fact, the impacts on the imports of the stand alone area A^1 are exactly in the opposite direction to those under the criterion change from $\mathscr{C}$ to $\mathscr{C}^a$. On the other hand, the imports of the nested area A^2 exhibit similar results to those under the criterion change from $\mathscr{C}$ to $\mathscr{C}^a$. We plot these outcomes for the same August week in Fig. 5. We note that the impacts are pronounced in both peak and off-peak hours.

We next examine the monetary impacts of the changes in the security criterion as measured by the relative social welfare metric. We use the daily social welfare as the basic metric in this investigation. We first normalize the daily social welfare values using the average value of the daily social welfare under the reference criterion $\mathscr{C}$ as a base value. We use the normalized values to compare the impacts with respect to the values under the reference criterion, as well as, across study periods of different durations. In this way, the comparisons are both consistent and meaningful. We can interpret the results to understand the nature of the impacts and how they relate to the values attained under the reference criterion $\mathscr{C}$. For concreteness, we

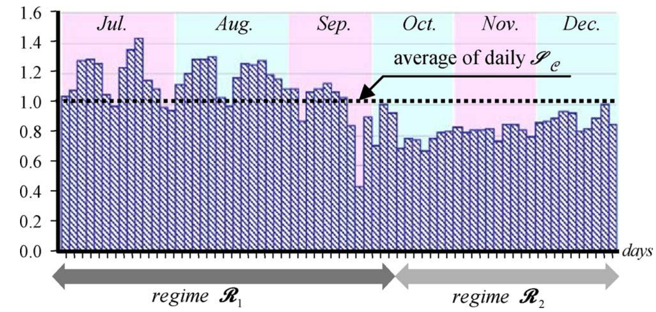

Fig. 6. Normalized daily social welfare under criterion $\mathscr{C}$.

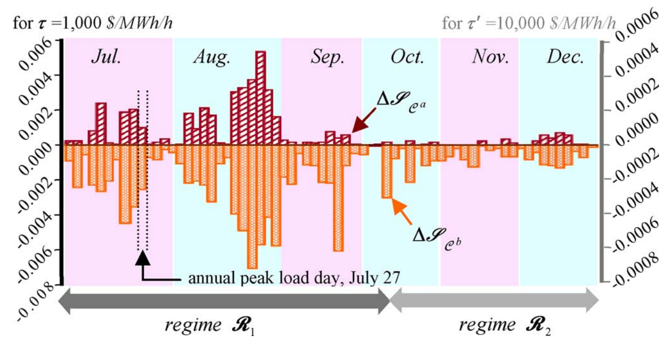

Fig. 7. Normalized daily impacts on social welfare.

use a value of $\tau = 1000$ $\$/MWh/h$ for evaluating the benefits of the buyers submitting fixed demand. We first consider the economic repercussions of the increased import capabilities arising from the relaxation of the security criterion from $\mathscr{C}$ to $\mathscr{C}^a$. Throughout the study period, the increased import capabilities are utilized leading to higher market efficiencies. We may view these improvements as a measure of the "costs" of not violating the constraints due to the double element contingencies in the reference criterion. On the other hand, the decreased import capabilities arising from changing the criterion from $\mathscr{C}$ to $\mathscr{C}^b$ may lower the social welfare. Indeed, such reductions are present throughout the study period. We may interpret these reductions to be a measure of the "costs" of replacing corrective for preventive control actions. The plot of the normalized daily social welfare values under the reference criterion $\mathscr{C}$ is given in Fig. 6 for the set of days $\mathscr{D}_r$. The plots of the changes in social welfare arising from a change of the security criterion are shown in Fig. 7. In this figure, we also provide the normalized impacts considering a different value of $\tau' = 10\,000$ $\$/MWh/h$. Note that, the different values of τ and τ' impact the normalized values but do not affect the nature of the impacts. We provide some of the statistics related to the maximum, the mean and the standard deviation of the values of relative social welfare metrics under the regimes $\mathscr{R}_1$ and $\mathscr{R}_2$ for each security criterion change in Table III.

We obtain additional insights into the impacts of the security criterion change on the market participants in each area by studying the disaggregation of the metrics $\Delta\mathscr{S}_{\mathscr{C}^a}$ and $\Delta\mathscr{S}_{\mathscr{C}^b}$. The area by area contribution is in line with the changes in the utilization of the modified import/export capabilities. We plot the changes of the import areas A^1 and A^2, and the export area A^5, contribution to the social welfare in

TABLE III
STATISTICAL ANALYSIS OF THE RELATIVE SOCIAL WELFARE METRIC VALUES UNDER THE REGIMES $\mathscr{R}_1$ AND $\mathscr{R}_2$ (BASIS IS $\mathscr{C}$)

criterion	regime	maximum	mean	standard deviation
$\mathscr{C}^a$	$\mathscr{R}_1$	0.00541	0.00098	0.00130
	$\mathscr{R}_2$	0.00070	0.00012	0.00023
$\mathscr{C}^b$	$\mathscr{R}_1$	-0.00715	-0.00224	0.00182
	$\mathscr{R}_2$	-0.00215	-0.00068	0.00051

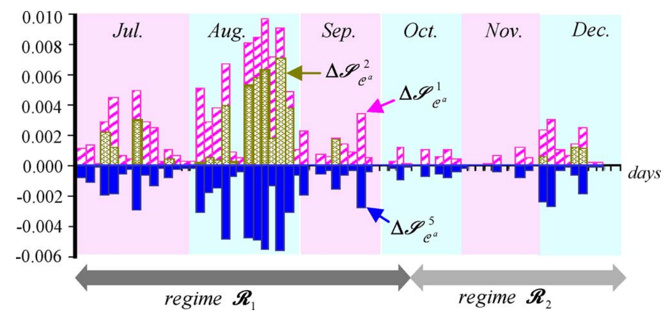

Fig. 8. Change in each area's contributions to social welfare under $\mathscr{C}^a$.

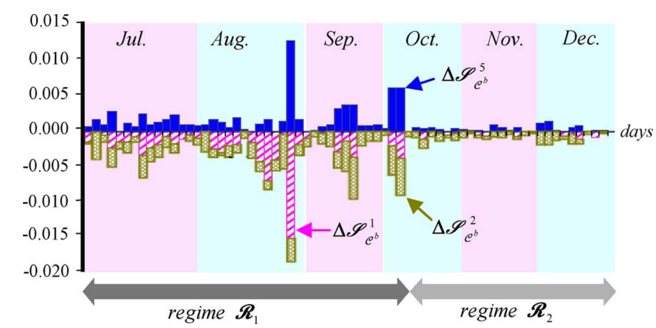

Fig. 9. Change in each area's contributions to social welfare under $\mathscr{C}^b$.

Fig. 8 (9) corresponding to shifting the security criterion from $\mathscr{C}$ to $\mathscr{C}^a$ ($\mathscr{C}^b$).

The price-responsive demand that characterizes regime $\mathscr{R}_2$ plays an important role in the nature of the results. In general, as the willingness to pay of the buyers increases, the absolute value of the relative social welfare metric increases, attaining its highest value for fixed demand for each security criterion considered. Therefore, the impacts of the change in security criterion to either $\mathscr{C}^a$ or $\mathscr{C}^b$ on the social welfare are more pronounced for the fixed demand regime $\mathscr{R}_1$ than the price responsive regime $\mathscr{R}_2$, as we observe in the plots of Figs. 6–9. Also, for a price-responsive demand with a uniformly low willingness to pay, the impacts may be small, and in certain cases may be negligibly so. The relaxation of the security criterion from $\mathscr{C}$ to $\mathscr{C}^a$ by not taking into account the double element contingencies, results in an insignificantly small relative social welfare metric values under the regime $\mathscr{R}_2$. The tightening of the security criterion from $\mathscr{C}$ to $\mathscr{C}^b$ using preventive actions to replace corrective ones reduces the social welfare. In fact, by utilizing the corrective control capabilities of the resources in the presence of price-responsive demand, the ISO-NE is able to decrease the economic impacts of the double tie line contingencies. Note that the extent of such an ability depends on various factors including the topology of the system, the characteristics of the generating units and the bids/offers of the market participants.

These findings of the comparative assessment lead us to conclude that the reference criterion $\mathscr{C}$ is, for all intents and purposes, more appropriate for the ISO-NE *DAM* than either of the two security criteria considered. Through this study, we also gain important insights on the role of price-responsive demand and the selected security control action. In fact, a key finding of the ISO-NE study is that the economic efficiency of the electricity markets need not decrease when a power system is operated under a stricter criterion as long as there is price-responsive demand. The proposed approach provides good insights into the ramification of changing the security criterion on both qualitative and quantitative basis.

V. Concluding Remarks

In this paper, we propose an approach for the assessment of market performance under a specified security criterion and quantification of the market performance impacts due to a change in the criterion. The proposed approach provides, for the first time, a useful tool to the *RTO* to analyze the interdependence between market performance and the system security. The ability to quantify the monetary impacts of complying with a specified security criterion makes the approach useful in regulatory studies, longer–term planning activities and short–term activities related to the market and system operations. In fact, the tool enables the *RTO* to make better informed decisions. The proposed approach has a wide range of applications. These include the studies for the justification by the *RTO* to modify its decision for the selected security criterion and for and the cost/benefit analysis of network improvements to mitigate the market performance impacts of a set of specified contingencies. We illustrate the application of the proposed approach on the ISO-NE *DAM* to analyze whether the economic efficiency of the ISO-NE *DAM* is adversely impacted with the current security criterion in force. Our investigation provides important insights into the role of price-responsive demand and that of the security control actions. In fact, a key finding of this study is that the economic efficiency of the electricity markets need not decrease when a power system is operated under a stricter criterion as long as there is effective price-responsive demand and appropriate control actions are deployed

As the real-time energy markets, or *RTM*, become more prominent, the comparative assessments of a security criterion change have to be broadened to include the impacts on *RTM*. To be able to accomplish this broadened scope, the incorporation of a multi-settlement system [20], [21], involving the *DAM* and the *RTM* is required. In addition, the growing impacts of bilateral transactions also need to be explicitly considered in the quantification of security criterion change impacts. The studies extending the proposed approach to incorporate the multi-settlement system and the bilateral transactions will be reported in a future work.

Appendix A
Notation

RTO System:

$\mathcal{A} \triangleq \{A^k : k = 1, \dots, K\}$	Set of interconnected areas.
$\boldsymbol{\mathcal{N}}^k$	Set of nodes in A^k with $\lvert\boldsymbol{\mathcal{N}}^k\rvert = N^k$.
$\underline{\boldsymbol{\chi}}$	Vector of the system states or dependent variables.
$\underline{\boldsymbol{\gamma}}$	Vector of the control or independent variables that are not associated with real power.

The Sellers:

s_i^k	Seller at node $i \in \boldsymbol{\mathcal{N}}^k$.
$p_{s_i^k}$	Real power supply of s_i^k.
$\beta_{s_i^k}(p_{s_i^k})$	Integral of the marginal offer price of s_i^k as a function of $p_{S_i^k}$.
$\mathscr{S}^k = \{s_i^k, \dots, s_{N^k}^k\}$	Set of sellers in area A^k.
$\underline{\boldsymbol{p}}_s^k = \left[p_{s_1{}^k}, \dots, p_{s_{N^k}^k}\right]^T$	Real power injection vector for A^k.
$\underline{\boldsymbol{p}}_s = \left[(\underline{\boldsymbol{p}}_s^1)^T, \dots, (\underline{\boldsymbol{p}}_s^k)^T\right]^T$	System real power injection vector.
$\underline{\boldsymbol{\Delta p}}_s$	Vector of corrective control capabilities of the sellers.

The Buyers:

b_i^k	Buyer at node $i \in \boldsymbol{\mathcal{N}}^k$.
$p_{b_1^k}$	Real power consumption of b_i^k.
$\beta_{b_i^k}(p_{b_i^k})$	Integral of marginal bid price of b_i^k as a function of $p_{b_i^k}$.
$\mathscr{B}^k = \{b_1^k, \dots, b_{N^k}^k\}$	Set of buyers in area A^k.
$\underline{\boldsymbol{p}}_b^k \triangleq \left[p_{b_1^k}, \dots, p_{b_{N^k}^k}\right]^T$	Vector of real power withdrawal for the area A^k.
$\underline{\boldsymbol{p}}_b = \left[(\underline{\boldsymbol{p}}_b^1)^T, \dots, \underline{\boldsymbol{p}}_b^K)^T\right]^T$	Vector of real power withdrawal.
$\underline{\boldsymbol{\Delta p}}_b$	Vector of corrective control capabilities of the buyers.

The Bilateral Transactions:

$\omega_w = \{m_w, n_w, t_w\}$	Bilateral transaction of amount t_w from the seller at node $m_w \in \boldsymbol{\mathcal{N}}^k$ to the buyer at node $n_w \in \boldsymbol{\mathcal{N}}^r$.
$\mathcal{W} = \{\omega_1, \dots, \omega_W\}$	Set of desired bilateral transactions.
$\alpha_w(t_w)$	Benefit function of the transaction ω_w for consummating t_w.

$\underline{\boldsymbol{t}} \triangleq [t_1, \ldots, t_W]^T$	Vector of the bilateral transaction amounts.
$\underline{\boldsymbol{\Delta t}}$	Vector of corrective control capabilities of the buyer and the seller pairs for bilateral transactions.

Security Criterion:

$\mathscr{C}$	Security criterion.
$\mathscr{J}_{\mathscr{C}}$	Set of indices of the contingencies under the security criterion $\mathscr{C}$.

Appendix B
Construction of $\mathscr{D}_r^i$

Let $\mathscr{D} = \{d_q : q = 1, \ldots, D\}$ be the set of days in the month i. We denote the day d_q peak demand load by p_{d_q}. We reorder the set of the demand values $\{p_{d_1}, \ldots, p_{d_D}\}$ as $\{\tilde{p}_1, \ldots, \tilde{p}_D\}$ with $\tilde{p}_j \geq \tilde{p}_{j+1}$ where $\tilde{p}_j$ denotes the jth largest value of the month. We construct the ordered daily load curve using the set of points $\{(0, \tilde{p}_1), (1, \tilde{p}_2), \ldots, (D-1, \tilde{p}_D)\}$. This curve has at most D distinct load levels. We normalize the time axis using D as the base value and construct the so-called load duration curve (*LDC*) $\mathcal{L}(\cdot)$ as a piece-wise step function using the set of points $\{(0, \tilde{p}_1), (1/D, \tilde{p}_2), \ldots, ((D-1)/D, \tilde{p}_D)\}$. We super-pose the grid with k equally distributed *LDC* factors

$$0 = \psi_0 < \psi_1 < \cdots < \psi_{k+1} = 1$$

on the time axis. We determine the load level $\hat{p}_j = \boldsymbol{\mathcal{L}}(\psi_j)$ for each ψ_j. We choose k so that the $(k+2)$ load values are distinct and

$$\hat{p}_0 > \hat{p}_1 > \cdots > \hat{p}_{k+1}.$$

We use the load levels to subdivide the interval between $\hat{p}_0$ and $\hat{p}_{k+1}$ into $(k+2)$ load tranches

$$\mathcal{P}_j = \begin{cases} \left[\hat{p}_{k+1}, \frac{\hat{p}_k + \hat{p}_{k+1}}{2}\right] & j = k+1 \\ \left(\frac{\hat{p}_{j-1} + \hat{p}_j}{2}, \frac{\hat{p}_j + \hat{p}_{j+1}}{2}\right] & j = 1, \ldots, k \\ \left(\frac{\hat{p}_0 + \hat{p}_1}{2}, \hat{p}_0\right] & j = 0 \end{cases}$$

and determine from the time axis the corresponding duration n_j of each tranche. Note that n_j is an integer multiple of $1/D$ and $\sum_{j=o}^{k+1} n_j = 1$. We define

$$\hat{\psi}_j = \sum_{s=0}^{j-1} n_s, j = 1, \ldots, k.$$

We construct $\boldsymbol{\mathcal{L}}^a(\cdot)$ from the $(k+2)$ load levels using the set of points $\{(0, \hat{p}_0), (\hat{\psi}_0, \hat{p}_1), \ldots, (\hat{\psi}_k, \hat{p}_{k+1})\}$ and use it to approximate $\boldsymbol{\mathcal{L}}(\cdot)$. For each load level $\hat{p}_j$ of $\boldsymbol{\mathcal{L}}^a(\cdot)$, we identify the day d_q with $p_{d_q} = \hat{p}_j$. In case of two or more such days, we select the most or more recent day. We construct $\mathscr{C}_r^i$ using these $(k+2)$ selected days. We illustrate such construction in Fig. 10.

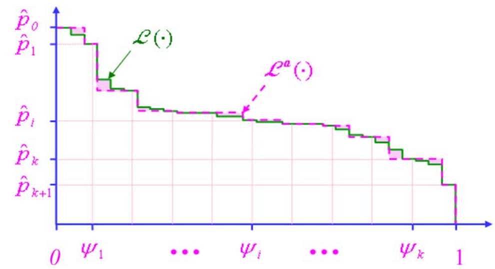

Fig. 10. Construction of $\mathcal{L}^a(\cdot)$ from $\mathcal{L}(\cdot)$.

We measure the "goodness" of the approximation in terms of an error based on the monthly energy. We define the error in the *LDC* approximation by

$$\varepsilon(k) = \int_0^1 |\mathcal{L}^a(x;k) - \mathcal{L}(x)| dx \Big/ \int_0^1 \boldsymbol{\mathcal{L}}(x) dx.$$

We compare the value of $\varepsilon(k)$ with a specified error tolerance value $\bar{\varepsilon}$. If the error fails to satisfy $\bar{\varepsilon}$, k is increased until the tolerance check is satisfied and select the corresponding $\mathscr{D}_r^i$.

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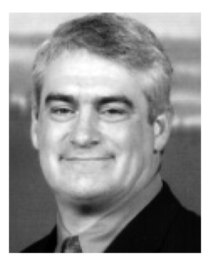

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