Improving Demand Response and Bid-Consistency of Price Outcome in the Security-Constrained Dispatch Scheduling

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***Abstract*—The primary objective of this paper is to design a security-constrained locational marginal pricing framework with specific emphasis on creating clear incentive for the demand side to make participation in serving the reserve option. Both the contingency forms, such as line outage and generator outage, are taken into account. The reserve services from the demand side are identified from the respective energy requests only, based upon a concept of load service security. Different prices are established for generating and load entities. Those are defined as generator and load locational marginal prices (LMPs), respectively. The load LMPs are further differentiated based upon the service security levels requested by different load entities. In the case of any system stress due to security constraints, the load prices go higher for a higher level of service security. Therefore, the necessary price signal is generated to control the service security requests. The prices that are established also resolve the overcharge and underpayment issues involved in the conventional security-constrained market optimizations. The price split that takes place is well characterized to provide clear price signals for future investments. The compatibility of financial transmission rights with the new pricing framework is also addressed.**

***Index Terms*—Bid-consistency, demand response, financial transmission right, generator outage, line outage, locational marginal price, reserve service, service security.**

NOMENCLATURE

Numbers:

η	Total number of energy bids.
ξ	Number of different types of contingency.
ϖ	Number of possible contingency events.
χ	Number of different types of independent upward reserve service.
G	Number of generators present in the system.
L	Number of lines in the network.
M	Number of possible service security levels.
N	Number of network buses.

Variables in OPF calculation:

$\boldsymbol{\delta}$	$(N \times 1)$ bus voltage angle vector representing the pre-contingency system state.
$\boldsymbol{\delta}^{(c)}$	$(N \times 1)$ bus voltage angle vector representing the system state after the occurrence of Contingency c.
$\boldsymbol{P}$	$(\eta \times 1)$ vector representing the cleared amounts towards energy bids.
P_{slack}	Slack power.
$\underline{\boldsymbol{P}}_{\boldsymbol{bus}}^{(c)}$	$(N \times 1)$ vector representing the minimum active power injections to be maintained at different buses after Contingency c.
$\overline{\boldsymbol{P}}_{\boldsymbol{bus}}^{(c)}$	$(N \times 1)$ vector representing the maximum permissible active power injections at different buses following Contingency c.
$\boldsymbol{R}_s$	$(G \times 1)$ vector representing the cleared amounts towards the bids (submitted by generators) for the sth type of upward reserve service.
$\widetilde{\boldsymbol{R}}_s$	$(N \times 1)$ vector representing the net nodal upward reserves of the sth type procured independently from the generators.
$\widetilde{\boldsymbol{R}}_{\boldsymbol{cn},w}$	$(N \times 1)$ vector representing the net nodal upward reserves procured independently from generators for the wth type of contingency.

Parameters in OPF calculation:

α_i	Estimated lost fraction of the total generation schedule (over the system) because of the outage of Generator i.
γ_i	Estimated lost fraction (for a particular type of contingency) of the total upward reserve schedule of generators (over the system) because of the outage of Generator i.
$\boldsymbol{\rho}$	$(M \times 1)$ vector defining the different levels of service security.
$\sigma_i^{(c)}$	Binary quantity defining the service status of the ith generating unit after the occurrence of Contingency c (0 if the unit is out and 1 if it is in service).

Manuscript received March 24, 2012; revised April 11, 2012, August 11, 2012, October 31, 2012, and January 03, 2013; accepted January 06, 2013. Date of publication February 05, 2013; date of current version July 18, 2013. Paper no. TPWRS-00301-2012.

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Digital Object Identifier 10.1109/TPWRS.2013.2239668

$\varsigma_l^{(c)}$ Binary quantity defining the service status of Line l after the occurrence of Contingency c (0 if the line is out and 1 if it is in service).

$\phi_{w,s}$ Binary quantity defining the utilization status of the sth type of upward reserve service for the wth type of contingency (1 if utilized and 0 if not utilized).

$\varphi_{c,w}$ Binary quantity defining the identity status of Contingency c as a wth type of contingency (1 if identified and 0 if not identified).

$\boldsymbol{\Omega}$ $(N \times 1)$ slack weight vector.

$\boldsymbol{F_{max}}$ $(L \times 1)$ vector defining line flow limits.

$\boldsymbol{P_{max}}$ Upper limit on $\boldsymbol{P}$.

$\boldsymbol{P^d_{fix,k}}$ $(N \times 1)$ vector representing the nodal fixed loads corresponding to the kth level of service security.

$\boldsymbol{P^g_{fix}}$ $(N \times 1)$ vector representing the nodal fixed power generations.

$\boldsymbol{P^{gen}_{fix}}$ $(G \times 1)$ vector defining the fixed MW schedules of the generators.

$\boldsymbol{P^{gen}_{max}}$ $(G \times 1)$ vector defining the maximum MW limits of the generators.

$\boldsymbol{P^{gen}_{min}}$ $(G \times 1)$ vector defining the minimum MW limits of the generators.

$\boldsymbol{R_{max,s}}$ Upper limit on $\boldsymbol{R}_s$.

$\widetilde{\boldsymbol{R}}_{\boldsymbol{fix},s}$ $(N \times 1)$ vector representing the net nodal fixed upward reserves of the sth type from generators.

r_l Resistance of the lth line (in per unit).

x_l Reactance of the lth line (in per unit).

Parameters in LMP decomposition:

$\boldsymbol{L_F}$ $(N \times 1)$ vector defining the loss sensitivities to the specified nodal active power injections around the optimal system state.

$\boldsymbol{S}$ $(2L \times N)$ matrix defining the line flow (both forward and reverse) sensitivities to the specified nodal active power injections around the optimal system state.

General constants:

$\boldsymbol{U_z}$ $(z \times z)$ identity matrix.

$\boldsymbol{0_z}$ $(z \times 1)$ vector of all zeros.

$\boldsymbol{1_z}$ $(z \times 1)$ vector of all ones.

Functions:

$\boldsymbol{f_F}(.)$ $(L \times 1)$ function vector defining pre-contingency active power flows (lossless) over different lines corresponding to a particular system state.

$\boldsymbol{f_{inj}}(.)$ $(N \times 1)$ function vector defining the pre-contingency active power flows into the network at different buses for a particular system state.

$\boldsymbol{f^{(c)}_{inj}}(.)$ $(N \times 1)$ function vector defining active power flows into the network at different buses for a particular system state after the occurrence of Contingency c.

$\boldsymbol{f_{loss}}(.)$ $(L \times 1)$ function vector defining pre-contingency active power losses in different lines corresponding to a particular system state.

$W(.)$ Social-welfare function.

$W^{opt}(.)$ Optimal social-welfare as the function of certain parameters.

Indices:

$fr(l)$ "From" end bus of the lth line.

$to(l)$ "To" end bus of the lth line.

Sets:

$\Gamma_{gn,n}$ Set of generation bids from Bus n.

$\Gamma^{(k)}_{ld,n}$ Set of load bids from Bus n corresponding to the kth level of service security.

$\Gamma^{(k)}_{tr,m,n}$ Set of bilateral transaction bids over the path from Bus m to Bus n corresponding to the kth level of service security.

Prices and OPF solutions:

$\boldsymbol{\lambda^{(k)}_d}$ $(N \times 1)$ nodal LMP vector for energy established for the loads corresponding to the kth level of service security.

$\boldsymbol{\lambda^{(k)}_{d,con}}$ Congestion component of $\boldsymbol{\lambda^{(k)}_d}$.

$\boldsymbol{\lambda^{(k)}_{d,enr}}$ Energy component of $\boldsymbol{\lambda^{(k)}_d}$.

$\boldsymbol{\lambda^{(k)}_{d,loss}}$ Loss component of $\boldsymbol{\lambda^{(k)}_d}$.

$\boldsymbol{\lambda_g}$ $(N \times 1)$ nodal LMP vector established for the energy service of generators.

$\boldsymbol{\lambda_{g,con}}$ Congestion component of $\boldsymbol{\lambda_g}$.

$\boldsymbol{\lambda_{g,enr}}$ Energy component of $\boldsymbol{\lambda_g}$.

$\boldsymbol{\lambda_{g,loss}}$ Loss component of $\boldsymbol{\lambda_g}$.

$\boldsymbol{\lambda^{(s)}_R}$ $(N \times 1)$ nodal LMP vector established for the sth type of upward reserve service from generators.

$(.)^*$ Optimal solution of a primal variable or KKT solution of a dual variable.

I. Introduction

THE modern interconnected power systems carrying several GWs of power are to be operated in a highly secure fashion so as to prevent massive blackouts when there is a contingency. The power transfer over a transmission network should, therefore, be carefully planned with due consideration for the possible outage events. In one approach, the system operation can be decided in a way so that it can survive any contingency without requiring the intervention of the system operator. This is the classical preventive model [1] of the security-constrained optimal power flow (SCOPF) application. Alternatively, a corrective strategy [2], [3] can also be employed to manage system security. For the corrective approach, sufficient adjustment provisions are left while preparing the generation and load schedules for the normal system operation. If a contingency happens, necessary adjustments are called for by the system operator so as to bring the system back into a permissible operating condition.

Ideally, the preventive approach is more robust compared to the corrective approach since the former does not need to rely upon the slow response of the system operator to recover from any overload or power imbalance. Thus, the threat of catastrophe because of immediate overload or power imbalance is minimum if a preventive scheduling is performed. However, the problem with the preventive approach is its tendency to produce a very conservative solution [4]. The problem becomes more pronounced in the case the so called slack power is suppressed and generator contingencies are considered. This may, in turn, significantly hamper the economy of the normal day-to-day operation of the power system. It is not justified to provide security to the system at the cost of hampering the daily power service, especially when contingency is a quite infrequent phenomenon. The corrective strategy, on the other hand, attempts to achieve network security without much hampering the daily load service. There is also a proposal for a mixed approach [5] combining the best features of preventive and corrective mechanisms. However, the particular model is also prone to produce a very conservative solution without the support of the slack power.

The practicality and facts discussed above make the corrective approach more preferable compared to the preventive approach. The prospective evolution of smart grid technologies with grid automation will further enhance the security performance of the corrective mechanism. In the corrective approach, it is required to procure some reserves on power productions and consumptions for utilization on the occurrence of a contingency. The reserve services are primarily classified as upward reserve and downward reserve [6], [7]. The upward reserves are used whenever there is a need to increase the active power injections into the network. It may also be required to decrease the active power injections, for which the downward reserves are utilized. The procurement of reserve services is usually made by inviting reserve bids [6]–[16] both from generating and load entities. The production or consumption level of an entity can be adjusted anywhere within the procured reserve band when there is a contingency.

There are two different paradigms of acquiring reserve services. Those differ in the way by which the outage of a generating unit is modeled at a location. For the first approach [6], [7], the exact amount of generation (corresponding to the normal schedule) that is lost because of the outage of a generating unit is precisely taken into account. The outage status of the generating unit is also precisely considered in the calculation of reserve utilization. In the other approach [8]–[15], the lost amount of generation because of a generator contingency is estimated beforehand and is simply modeled as a sudden increase of power demand at the respective location. The estimation of generation loss is made either in MW [8]–[12] or in terms of a fraction of the total generation (or load) schedule within a zone [13]–[15].

The primary drawback of the conventional reserve bidding approaches is that there is no proper incentive to encourage demand side for providing reserve services. The availability of reserve services from the demand side in addition to the prevailing reserve services from generators can be useful to improve the economy of the system operation [16], [17]. The active participation of load entities to provide the security service against grid disturbances is also one of the key objectives of the smart grid initiative [18], [19]. Unlike generators, it is, however, not possible to make the reserve service mandatory for the load entities. This is because it is not possible to pre-define an adjustment range for a load entity and the same keeps on varying dynamically depending upon the types of load that are going to be served. At the same time, a load entity may not be able to see any benefit in providing reserve services when there is a unique energy price for all the loads at a location.

Another common problem associated with energy-reserve co-optimization is the lack of bid-consistency in the price outcome for the marginal pricing. For example, the price that a generator receives for energy or reserve may be higher than the quoted price even when the respective bid is only partially selected. Similarly, the network usage price charged to a partially selected bilateral transaction request can be lower than the corresponding bid price. Such a price outcome can subsequently create the opportunity for an entity to override its competitors by submitting a false price quotation. There is also the other form of bid-inconsistency in the existing reserve bidding approaches. It can happen that the price charged to a load or transaction bid is higher than its quoted price. Similarly, the price paid to a generation bid can be lower than its quoted price. Results of this kind are specifically harmful for the bilateral transactions.

In this paper, an enhanced security-constrained market optimization framework is suggested to aid the growth of demand response towards system security as well as to partially resolve the issue of bid-inconsistency of the price outcome. It is aimed to generate suitable price signals to encourage load entities for providing reserve services. At the same time, it is attempted to curb any happening of underpayment or overcharge in the pricing result. For the methodology proposed, no separate reserve bids are invited from the load entities. The upward reserve service that a load entity is ready to provide is rather recognized from a service security request that the respective load entity makes in its energy bid. It may not be practically feasible to instruct load entities in real time for increasing their active power consumptions as a countermeasure to contingencies. Therefore, no consideration is made for the downward reserve services from the load entities. For generators, both the upward and downward reserve services are considered as usual. As in the actual practice [10], [11], the reserve settlements are carried out based upon the service availability instead of looking at the actual service utilization. However, no cost or payment consideration is made for the downward reserve service of a generator. At the same time, the ramp down limits of generators are ignored. It is obvious that there will be no monetary loss for a generator in the case it has to reduce its power production while earning the same revenue. So far as the viability of ignoring the ramp down limit is concerned, there may not be any hard technical burden to rapidly reduce the output of a generator. Of course, the steam output of a boiler cannot be reduced suddenly. However, the additional steam that is temporarily taken from the boiler can simply be discharged through the bypass valve allowing only the needed volume of steam into the turbine. Therefore, the power production level of a generator may be reduced without any ramp rate burden. For the representation of generator contingencies, the estimation-based approach of [13]–[15] is adopted. With regard to pricing, the locational marginal prices (LMPs) for energy are classified as generator and load LMPs. The load LMPs are also differentiated according to the requested levels of service security. The modified definition of financial transmission rights (FTRs) [20], [21] for the new pricing rule is subsequently established, and their implementation concerns are discussed in fine details.

The rest of the paper is organized as follows: The formats of the generation, load and transaction bids for the proposed market optimization framework are discussed in Section II. The corresponding SCOPF formulation is shown in Section III. In Section IV, the decomposition of locational marginal prices is explained. The issues related to financial transmissions rights are resolved in Section V. A couple of case studies are performed in Section VI to verify the utility and potential of the proposed framework. Finally, the paper is concluded in Section VII.

II. Bid Formats for the Proposed Market Model

As mentioned, the market framework proposed uses a concept of service security that is to be requested by the load (or load serving) entities. The service security is quantified by a number ranging from zero to one. The use of the service security specification lies in defining the minimum fraction of the normal load that must be served even after the occurrence of a contingency. As an example, let ρ be the service security requested by a load entity. The load bid submitted by the entity is cleared by awarding P_d MW. The load service permitted for the respective entity should then be P_d MW for the normal system condition and at least ρP_d MW after the occurrence of any contingency.

It is obvious that each load bid should then have four components, namely, a MW request, a price quotation, the locational information and a service security specification. The self-scheduled requests are also to be submitted in the same way, but without quoting any price. It is to be noted that the service security specified in a load request is solely the choice of the respective load entity and should be obeyed by the system operator while performing dispatch scheduling. A load entity may also prefer to classify its loads based upon the desired levels of service security. A separate bid should then be submitted for each load group thus formed.

There is no separate payment to be made for the reserve service provided by a load entity. The price quoted by a load entity in its energy bid should, therefore, be carefully estimated taking into account the possible curtailment cost. The same can be done by employing the concept of expected benefit function [22]. For example, by considering the worst case scenario of load reduction, the expected benefit function can be formulated as follows:

$$B_{exp}(P_d) = p_0 B(P_d) + p_c B(\rho P_d). \tag{1}$$

Here, the function $B(*)$ defines the benefit that the load entity will receive by serving $*$ MW to the end consumers. Thus, P_d being the scheduled quantity for the normal system operation, the benefit of the load entity will be $B(P_d)$ when there is no outage. On the other hand, if there is a contingency, the benefit of the load entity can come down to $B(\rho P_d)$. Given that p_0 and p_c are the probabilities of normal and contingent system operations, the expected benefit function $B_{exp}(*)$ of the load entity can then be conservatively defined according to (1) with a further assumption that the load entity will be awarded almost the same quantity for each hour within the time frame of interest. Subsequently, the load entity can determine the bid price of its load request simply by differentiating $B_{exp}(P_d)$ with respect to P_d.

For a generator, the energy and reserve bids are still to be independently submitted. Thus, the format of a generation bid remains unchanged. In the case of a bilateral transaction request, it is, however, required to specify the service security desired at the load end. The format of an "up to congestion charge" bid (that is submitted for executing a bilateral transaction) should be accordingly updated. For a bilateral transaction also, all the settlements are to be carried out only according to whatever is scheduled for the normal system operation.

III. OPF Formulation

In this section, a generic formulation of market optimization is shown considering both DC optimal power flow (DCOPF) and AC optimal power flow (ACOPF) applications. However, for the sake of simplicity, the bus voltage magnitudes are assumed to be fixed at one per unit and the reactive power availability (for shunt compensation) is assumed to be affluent. Thus, the state variables are limited only to the bus voltage angles and no reactive power term is considered. As mentioned previously, the approach of [13]–[15] is followed to represent generator contingencies. The lost generation percentage is estimated with respect to the total generation schedule over the system. In the same way, the lost reserve percentage is estimated with respect to the total reserve schedule over the system.

There is always a unit commitment task involved in the whole process of system operation scheduling. However, since the main concern of this paper is with pricing for variable costs, the market optimization is studied only for a given unit commitment schedule. Recovery of the fixed costs, such as star-up costs and minimum load costs (of generators), is, therefore, not addressed in this paper. The minimum MW to be produced by a generator is to be represented as a fixed generation in the OPF calculation. For a non-committed generator, the minimum MW can equivalently be considered as zero and the respective generator can be assumed like a synchronized power source with no participation in the energy market.

The objective of the day-ahead market optimization problem is to maximize the combined social welfare function as per the energy and reserve bids submitted by different entities. The same can be formulated as follows:

$$\text{minimize}\left\{-W(\boldsymbol{P}, \boldsymbol{R}_1, \boldsymbol{R}_2, \ldots, \boldsymbol{R}_\chi)\right\}. \tag{2}$$

The energy schedules prepared must satisfy the network constraints corresponding to the normal system operation. The network constraints to be satisfied corresponding to the normal system operation are as follows:

$$h_0 : P_{slack} = 0 \tag{3}$$

$$\boldsymbol{h_1} : \boldsymbol{AP} + \boldsymbol{P^g_{fix}} - \widehat{\boldsymbol{P}}^{\boldsymbol{d}}_{\boldsymbol{fix}}\boldsymbol{1_M} + \boldsymbol{\Omega} P_{slack} - \boldsymbol{f_{inj}}(\boldsymbol{\delta}) = \boldsymbol{0_N} \tag{4}$$

$$\boldsymbol{g_1} : \boldsymbol{f_F}(\boldsymbol{\delta}) - \boldsymbol{F_{max}} \leq \boldsymbol{0_L} \tag{5}$$

$$\boldsymbol{g_2} : -\boldsymbol{f_F}(\boldsymbol{\delta}) - \boldsymbol{F_{max}} \leq \boldsymbol{0_L} \tag{6}$$

where

$$\widehat{\boldsymbol{P}}^{\boldsymbol{d}}_{\boldsymbol{fix}} = \begin{bmatrix} \boldsymbol{P^d_{fix,1}} & \boldsymbol{P^d_{fix,2}} & \cdots & \boldsymbol{P^d_{fix,M}} \end{bmatrix} \tag{7}$$

$$\begin{aligned} A_{n,j} &= 1 \quad \text{if } P_j \text{ is a generation at Bus } n \\ &= -1 \quad \text{if } P_j \text{ is a load at Bus } n \\ &= 0 \quad \text{if } P_j \text{ is not related to Bus } n. \end{aligned} \tag{8}$$

Here, all the active power quantities are expressed in MW. The primary objective behind introducing a slack power term is just to define the LMP decomposition. However, since the slack power is a virtual quantity in the market, the same is forced to become zero through (3). Constraints (4) define the nodal active power balance for the normal system operation. The net nodal active power injections caused by $\boldsymbol{P}$ is obtained by means of the $(N \times \eta)$ conversion matrix $\boldsymbol{A}$. Constraints (5) and (6) enforce the line capacity limits for the forward and reverse flows, respectively.

There are different types of reserve service (such as spinning reserve, non-spinning reserve and operating reserve) offered by generating entities [10], [11]. Each type of reserve is characterized by a particular response time. The response time refers to the maximum time that is required to bring the whole portion of a reserve into the service. The net nodal reserves corresponding to the different types of independent upward reserve service are given by

$$\boldsymbol{h_2^{(s)}} : \widetilde{\boldsymbol{R}}_s - \widetilde{\boldsymbol{A}}_{\boldsymbol{g}}\boldsymbol{R}_s - \widetilde{\boldsymbol{R}}_{\boldsymbol{fix},s} = \boldsymbol{0_N},\ s = 1 \text{ to } \chi \tag{9}$$

where

$$\begin{aligned} \tilde{A}_{g,n,i} &= 1 \quad \text{if Generator } i \text{ is located at Bus } n \\ &= 0 \quad \text{otherwise.} \end{aligned} \tag{10}$$

Matrix $\tilde{\boldsymbol{A}}_{\boldsymbol{g}}$ defines the incidences of generators on the system buses. The vector $\widetilde{\boldsymbol{R}}_{\boldsymbol{fix},s}$ is usually a zero vector. The reason behind incorporating the particular vector in (9) is just to define the reserve prices. Similarly to reserve services, contingencies are also classified into different categories. Usually, two types of contingency are considered. Those are defined as single contingency and double contingency, respectively. The single contingency refers to the outage of only one element, whereas, double contingency refers to the simultaneous outage of two elements. Each type of contingency is assigned a target recovery time. For example, the time limits to recover from a single contingency and a double contingency are defined as 10-min and 30-min, respectively, in [11]. Each type of contingency is supported by specific types of reserve service. As an example, spinning and non-spinning reserves are used both for single and double contingencies, whereas, operating reserves are used only for double contingencies. The net nodal upward reserves that are independently available for different types of contingency can then be derived as follows:

$$\boldsymbol{h_3^{(w)}} : \widetilde{\boldsymbol{R}}_{\boldsymbol{cn},w} - \sum_{s=1}^{\chi} \phi_{w,s}\widetilde{\boldsymbol{R}}_s = \boldsymbol{0_N},\ w = 1 \text{ to } \xi. \tag{11}$$

It is to be noted that the response times of the reserve services acquired for a particular type of contingency must be consistent with the respective target recovery time. For the reserve substitution approach followed in [10] and [11], the response time of a particular type of reserve should be exactly equal to the lowest recovery time among the related types of contingency. In the case of reserve substitution, a costlier reserve service can always be replaced with a cheaper reserve service for the given total reserve requirement. However, the reserve substitution is another source of bid-inconsistency in the reserve prices and, therefore, is not considered in this paper. In that case, the total response time of the different types of reserve to be used for a particular type of contingency should be equal to the corresponding contingency recovery time. It is also possible to define only one type of reserve exclusively for a particular type of contingency.

For a specific energy and reserve schedule, the minimum active power injections to be maintained at different buses following a contingency are given by

$$\begin{aligned} \boldsymbol{h_4^{(c)}} : \underline{\boldsymbol{P}}^{(c)}_{\boldsymbol{bus}} + \left(\boldsymbol{A_d P} + \widehat{\boldsymbol{P}}^{\boldsymbol{d}}_{\boldsymbol{fix}}\boldsymbol{1_M}\right) & \\ -\tilde{\boldsymbol{A}}_{\boldsymbol{g}}\widehat{\boldsymbol{\sigma}}^{(c)}\boldsymbol{P^{gen}_{min}} &= \boldsymbol{0_N},\ c = 1 \text{ to } \varpi \end{aligned} \tag{12}$$

where

$$\widehat{\boldsymbol{\sigma}}^{(c)} = \text{diag}\left(\sigma_1^{(c)}, \sigma_2^{(c)}, \cdots, \sigma_G^{(c)}\right) \tag{13}$$

$$\begin{aligned} A_{d,n,j} &= 1 \quad \text{if } P_j \text{ is a load at Bus } n \\ &= 0 \quad \text{otherwise.} \end{aligned} \tag{14}$$

The incidence matrix $\tilde{\boldsymbol{A}}_{\boldsymbol{g}}$ is defined in (10). The total loads at different buses corresponding to bid clearing results are obtained by pre-multiplying $\boldsymbol{A_d}$ [that is $(N \times \eta)$] with $\boldsymbol{P}$. It is to be mentioned again that the ramp down limits of generators are not considered here. The outage status of a generating unit is precisely taken into account (through $\widehat{\boldsymbol{\sigma}}^{(c)}$) in the definition of $\underline{\boldsymbol{P}}^{(c)}_{\boldsymbol{bus}}$. As defined, the elements of $\boldsymbol{P^{gen}_{min}}$ corresponding to non-committed generating units should be set to zero.

It is also required to determine the maximum permissible active power injections at different buses after a contingency. The same can be formulated as follows:

$$\boldsymbol{h_5^{(c)}} : \overline{\boldsymbol{P}}_{\boldsymbol{bus}}^{(c)} - \widehat{\boldsymbol{\beta}}^{(c)} \left(\boldsymbol{A_g P} + \boldsymbol{P_{fix}^{g}}\right) + \left(\underline{\boldsymbol{A}}_{\boldsymbol{d}}\boldsymbol{P} + \widehat{\boldsymbol{P}}_{\boldsymbol{fix\rho}}^{\boldsymbol{d}}\right) - \widehat{\boldsymbol{\psi}}^{(c)} \sum_{w=1}^{\xi} \varphi_{c,w} \widetilde{\boldsymbol{R}}_{\boldsymbol{cn},w} = \boldsymbol{0_N},\ c = 1 \text{ to } \varpi \quad (15)$$

where

$$\begin{aligned}
\underline{A}_{d,n,j} &= \rho_k \text{ if } P_j \text{ is a load of } k\text{th service security at Bus } n \\
&= 0 \quad \text{if } P_j \text{ is not a load at Bus } n \quad (16)\\
A_{g,n,j} &= 1 \quad \text{if } P_j \text{ is a generation at Bus } n \\
&= 0 \quad \text{otherwise} \quad (17)\\
\widehat{\boldsymbol{\beta}}^{(c)} &= \boldsymbol{U_N} - \tilde{\boldsymbol{A}}_{\boldsymbol{g}} \left(\boldsymbol{U_G} - \widehat{\boldsymbol{\sigma}}^{(c)}\right) \boldsymbol{\alpha} \boldsymbol{1}_{\boldsymbol{N}}^{T} \quad (18)\\
\widehat{\boldsymbol{\psi}}^{(c)} &= \boldsymbol{U_N} - \tilde{\boldsymbol{A}}_{\boldsymbol{g}} \left(\boldsymbol{U_G} - \widehat{\boldsymbol{\sigma}}^{(c)}\right) \boldsymbol{\gamma} \boldsymbol{1}_{\boldsymbol{N}}^{T} \quad (19)\\
\boldsymbol{\alpha} &= [\alpha_1\ \alpha_2 \cdots \alpha_G]^T \quad (20)\\
\boldsymbol{\gamma} &= [\gamma_1\ \gamma_2 \cdots \gamma_G]^T. \quad (21)
\end{aligned}$$

Here, the matrix $\underline{\boldsymbol{A}}_{\boldsymbol{d}}$ derives the net nodal load profile corresponding to $\boldsymbol{P}$ considering the situation of maximum possible load reduction. The total generations at different buses corresponding to bid clearing results are obtained by pre-multiplying $\boldsymbol{A_g}$ [that is also $(N \times \eta)$] with $\boldsymbol{P}$. Based upon the representation of generator contingencies followed in this paper, the loss of generation because of the outage of Generator i is given by $\alpha_i \boldsymbol{1}_{\boldsymbol{N}}^T(\boldsymbol{A_g P} + \boldsymbol{P_{fix}^g})$. Note that $\boldsymbol{1}_{\boldsymbol{N}}^T(\boldsymbol{A_g P} + \boldsymbol{P_{fix}^g})$ indicates the total generation schedule over the system. However, there will be a loss of generation because of Generator i only if the particular generator is out. Therefore, the loss of generation related to Generator i is given by $(1 - \sigma_i^{(c)})\alpha_i \boldsymbol{1}_{\boldsymbol{N}}^T(\boldsymbol{A_g P} + \boldsymbol{P_{fix}^g})$ for Contingency c. The generation loss pertaining to a particular generator will occur only at the bus where the generator is located. The generation losses at different buses can, therefore, be obtained through the $\tilde{\boldsymbol{A}}_{\boldsymbol{g}}$ matrix. Finally, the survived generations at different buses after Contingency c are given by $\widehat{\boldsymbol{\beta}}^{(c)}(\boldsymbol{A_g P} + \boldsymbol{P_{fix}^g})$. Apart from the generation loss, the loss of reserve is also modeled here. Similarly to $\widehat{\boldsymbol{\beta}}^{(c)}$, the survived reserves at different buses after Contingency c are obtained through $\widehat{\boldsymbol{\psi}}^{(c)}$. It is to be noted that the consideration of the loss of reserve is not made in the conventional estimation-based contingency approximations.

The minimum active power injections to be maintained at different buses following a contingency must not be higher than the active power injections required by the respective post-contingency system state. In the same way, the maximum permissible active power injections at different buses after a contingency must not be lower than the active power injections required by the corresponding post-contingency system state. The particular conditions are enforced through the following constraints:

$$\boldsymbol{g_3^{(c)}} : \underline{\boldsymbol{P}}_{\boldsymbol{bus}}^{(c)} - \boldsymbol{f_{inj}^{(c)}}(\boldsymbol{\delta}^{(c)}) \leq \boldsymbol{0_N},\ c = 1 \text{ to } \varpi \quad (22)$$

$$\boldsymbol{g_4^{(c)}} : -\overline{\boldsymbol{P}}_{\boldsymbol{bus}}^{(c)} + \boldsymbol{f_{inj}^{(c)}}(\boldsymbol{\delta}^{(c)}) \leq \boldsymbol{0_N},\ c = 1 \text{ to } \varpi. \quad (23)$$

Similarly to the normal system operation, the line flow limits should be satisfied also for the post-contingency system operation. The respective constraint formulation is shown in the following:

$$\boldsymbol{g_5^{(c)}} : \widehat{\boldsymbol{\varsigma}}^{(c)} \boldsymbol{f_F}(\boldsymbol{\delta}^{(c)}) - \boldsymbol{F_{max}} \leq \boldsymbol{0_L},\ c = 1 \text{ to } \varpi \quad (24)$$

$$\boldsymbol{g_6^{(c)}} : -\widehat{\boldsymbol{\varsigma}}^{(c)} \boldsymbol{f_F}(\boldsymbol{\delta}^{(c)}) - \boldsymbol{F_{max}} \leq \boldsymbol{0_L},\ c = 1 \text{ to } \varpi \quad (25)$$

where

$$\widehat{\boldsymbol{\varsigma}}^{(c)} = \operatorname{diag}\left(\varsigma_1^{(c)}, \varsigma_2^{(c)}, \cdots, \varsigma_L^{(c)}\right). \quad (26)$$

It is obvious that there is no need to consider the flow limit of a tripped line. This is ensured by multiplying the line status matrix $\widehat{\boldsymbol{\varsigma}}^{(c)}$ with $\boldsymbol{f_F}(.)$.

Since there are separate price bids from generators for the upward reserve services, the respective energy-reserve couplings should be recognized. The particular constraints can be formulated as follows:

$$\boldsymbol{g_7^{(w)}} : \boldsymbol{\Theta_g P} + \boldsymbol{P_{fix}^{gen}} + \sum_{s=1}^{\chi} \phi_{w,s} \boldsymbol{R}_s - \boldsymbol{P_{max}^{gen}} \leq \boldsymbol{0_G},\ \text{for } w = 1 \text{ to } \xi. \quad (27)$$

The $(G \times \eta)$ matrix $\boldsymbol{\Theta_g}$ derives the active power schedules of different generators corresponding to $\boldsymbol{P}$. The particular matrix is defined as follows:

$$\begin{aligned}
\Theta_{g,i,j} &= 1 \quad \text{if } P_j \text{ is related to Generator } i \\
&= 0 \quad \text{otherwise.} \quad (28)
\end{aligned}$$

Finally, the upper and lower limits on the energy and reserve bid variables are to be applied. That is,

$$\boldsymbol{q_1} : \boldsymbol{P} - \boldsymbol{P_{max}} \leq \boldsymbol{0_\eta} \quad (29)$$

$$\boldsymbol{q_2} : -\boldsymbol{P} \leq \boldsymbol{0_\eta} \quad (30)$$

$$\boldsymbol{q_3^{(s)}} : \boldsymbol{R}_s - \boldsymbol{R}_{\boldsymbol{max},s} \leq \boldsymbol{0_G},\ \text{for } s = 1 \text{ to } \chi \quad (31)$$

$$\boldsymbol{q_4^{(s)}} : -\boldsymbol{R}_s \leq \boldsymbol{0_G},\ \text{for } s = 1 \text{ to } \chi. \quad (32)$$

The upper limit on a reserve bid variable is to be set according to the ramp up capability of the respective generator within the specified response time.

It is to be noted that, the formulation shown above does not produce any precise post-contingency generation and load schedule. It is basically attempted to find a generation and load schedule for the normal system operation leaving sufficient provision for a secure post-contingency transition. The actual generation and load schedule for the post-contingency system operation can subsequently be determined based upon some rational criterion satisfying the adjustment limits of individual loads and generators. It is to be mentioned again that the financial settlement of reserve services is made only based upon the service availability, and not based upon the actual service utilization.

The Lagrangian function of the above optimization problem can be written as

$$\begin{aligned}\Lambda =& -W(\boldsymbol{P},\boldsymbol{R}_1,\boldsymbol{R}_2,\ldots,\boldsymbol{R}_\chi)+\nu_0 h_0+\boldsymbol{\nu_1}^T\boldsymbol{h_1}+\boldsymbol{\mu_1}^T\boldsymbol{g_1}\\ &+\boldsymbol{\mu_2}^T\boldsymbol{g_2}+\boldsymbol{\vartheta_1}^T\boldsymbol{q_1}+\boldsymbol{\vartheta}_2^T\boldsymbol{q_2}\\ &+\sum_{s=1}^{\chi}\left\{\boldsymbol{\nu_2}^{(s)^T}\boldsymbol{h_2}^{(s)}+\boldsymbol{\vartheta_3}^{(s)^T}\boldsymbol{q_3}^{(s)}+\boldsymbol{\vartheta_4}^{(s)^T}\boldsymbol{q_4}^{(s)}\right\}\\ &+\sum_{w=1}^{\xi}\left\{\boldsymbol{\nu_3}^{(w)^T}\boldsymbol{h_3}^{(w)}+\boldsymbol{\mu_7}^{(w)^T}\boldsymbol{g_7}^{(w)}\right\}\\ &+\sum_{c=1}^{\varpi}\left\{\boldsymbol{\nu_4}^{(c)^T}\boldsymbol{h_4}^{(c)}+\boldsymbol{\nu_5}^{(c)^T}\boldsymbol{h_5}^{(c)}+\boldsymbol{\mu_3}^{(c)^T}\boldsymbol{g_3}^{(c)}+\boldsymbol{\mu_4}^{(c)^T}\boldsymbol{g_4}^{(c)}\right.\\ &\qquad\left.+\boldsymbol{\mu_5}^{(c)^T}\boldsymbol{g_5}^{(c)}+\boldsymbol{\mu_6}^{(c)^T}\boldsymbol{g_6}^{(c)}\right\}.\end{aligned}\tag{33}$$

Here, ν, μ and ϑ are the Lagrangian multipliers. From the theory of sensitivity analysis [6], the nodal LMP vector for the energy services of generators can be derived as follows:

$$\begin{aligned}\boldsymbol{\lambda_g} =& \left\{\frac{\partial W^{opt}\left(\boldsymbol{P^g_{fix}},\widehat{\boldsymbol{P}}^{\boldsymbol{d}}_{\boldsymbol{fix}},\widetilde{\boldsymbol{R}}_{\boldsymbol{fix},1},\ldots,\widetilde{\boldsymbol{R}}_{\boldsymbol{fix},\chi}\right)}{\partial\boldsymbol{P^g_{fix}}}\right\}^T\\ =& -\boldsymbol{\nu_1}^*+\sum_{c=1}^{\varpi}\widehat{\boldsymbol{\beta}}^{(c)^T}\boldsymbol{\nu_5}^{(c)^*}.\end{aligned}\tag{34}$$

In the same way, the energy based nodal LMP vector for loads corresponding to the kth level of service security can be obtained as follows:

$$\begin{aligned}\boldsymbol{\lambda_d}^{(k)} =& -\left\{\frac{\partial W^{opt}\left(\boldsymbol{P^g_{fix}},\widehat{\boldsymbol{P}}^{\boldsymbol{d}}_{\boldsymbol{fix}},\widetilde{\boldsymbol{R}}_{\boldsymbol{fix},1},\ldots,\widetilde{\boldsymbol{R}}_{\boldsymbol{fix},\chi}\right)}{\partial\boldsymbol{P^d_{fix}}_{,k}}\right\}^T\\ =& -\boldsymbol{\nu_1}^*+\sum_{c=1}^{\varpi}\left\{\boldsymbol{\nu_4}^{(c)^*}+\rho_k\boldsymbol{\nu_5}^{(c)^*}\right\}.\end{aligned}\tag{35}$$

Finally, the locational marginal prices for different types of independent reserve services can be expressed in the following form:

$$\begin{aligned}\boldsymbol{\lambda_R}^{(s)} =& \left\{\frac{\partial W^{opt}\left(\boldsymbol{P^g_{fix}},\widehat{\boldsymbol{P}}^{\boldsymbol{d}}_{\boldsymbol{fix}},\widetilde{\boldsymbol{R}}_{\boldsymbol{fix},1},\ldots,\widetilde{\boldsymbol{R}}_{\boldsymbol{fix},\chi}\right)}{\partial\widetilde{\boldsymbol{R}}_{\boldsymbol{fix},s}}\right\}^T\\ =& \boldsymbol{\nu_2}^{(s)^*}\\ =& \sum_{w=1}^{\xi}\phi_{w,s}\boldsymbol{\nu_3}^{(w)^*}.\end{aligned}\tag{36}$$

The price to be paid by a load entity is equal to the load LMP at its location corresponding to the requested service security. Generators are essentially paid according to $\boldsymbol{\lambda_g}$ and $\boldsymbol{\lambda_R}^{(s)}$ for their energy and reserve services, respectively. Finally, the network usage price for a bilateral transaction can be determined simply by taking the difference between the load LMP at its sink location and the generator LMP (for energy) at its source location with due consideration for the specified load end service security.

According to the KKT necessary conditions of optimality, the partial differentiation of the Lagrangian function with respect to P_j must be equal to zero at the optimal solution. Let the symbol ζ_j be defined as follows:

$$\zeta_j=\vartheta^*_{1,j}-\vartheta^*_{2,j}+\sum_{w=1}^{\xi}\sum_{i=1}^{G}\mu_{7,i}^{(w)^*}\Theta_{G,i,j}.\tag{37}$$

Therefore, based upon the expressions of locational marginal prices, the following relationship can be obtained:

$$\begin{aligned}\frac{\partial W}{\partial P_j}\left(P_j^*\right) &= -\lambda_{g,n}+\zeta_j && \text{if } P_j\in\Gamma_{gn,n}\\ &=\lambda_{d,n}^{(k)}+\zeta_j && \text{if } P_j\in\Gamma_{ld,n}^{(k)}\\ &=\lambda_{d,n}^{(k)}-\lambda_{g,m}+\zeta_j && \text{if } P_j\in\Gamma_{tr,m,n}^{(k)}.\end{aligned}\tag{38}$$

The partial differentiation of $W(.)$ with respect to a load or transaction bid variable gives the respective bid price. In the same way, the partial differentiation of $-W(.)$ with respect to a generation bid variable gives the corresponding generation bid price. According to the complementary slackness condition, $\vartheta^*_{2,j}$ must be zero if P_j^* is non-zero. Therefore, ζ_j must be non-negative if Bid j is at least partially selected. This, in turn, indicates that there will be no underpayment to a generation bid as well as no overcharge to a load or bilateral transaction bid. Furthermore, for a partially selected load bid, ζ_j must be zero. This is because $\vartheta^*_{1,j}$ will additionally be zero in that case. Note that the third term on the right hand side of (37) must be zero for a load bid since the entries of $\boldsymbol{\Theta_g}$ corresponding to a load bid are always zero. Therefore, a partially selected load bid is charged exactly at its bid price. The above facts clearly indicate perfect bid consistency in load prices. In the same way, it can be shown that there will be no underpayment to the reserve services. However, there is also no underpayment issue for reserve bids in the conventional energy-reserve co-optimizations.

From the KKT necessary conditions of optimality, it can be further verified that $\boldsymbol{\nu_4}^{(c)^*}=-\boldsymbol{\mu_3}^{(c)^*}$ and $\boldsymbol{\nu_5}^{(c)^*}=\boldsymbol{\mu_4}^{(c)^*}$. Therefore, the generator and load LMPs can alternatively be expressed as follows:

$$\boldsymbol{\lambda_g}=-\boldsymbol{\nu_1}^*+\sum_{c=1}^{\varpi}\widehat{\boldsymbol{\beta}}^{(c)^T}\boldsymbol{\mu_4}^{(c)^*}\tag{39}$$

$$\boldsymbol{\lambda_d}^{(k)}=-\boldsymbol{\nu_1}^*+\sum_{c=1}^{\varpi}\left\{\rho_k\boldsymbol{\mu_4}^{(c)^*}-\boldsymbol{\mu_3}^{(c)^*}\right\}.\tag{40}$$

In order to have a unique LMP at a bus for energy, none of the constraints in (22) and (23) should be binding for the respective bus. This is obvious from (39) and (40). On the other hand, the load price at a bus will go higher for a higher level of service security in the case some of the security constraints in (23) are binding for the particular bus. This in turn helps in improving demand response to provide reserve services.

It is sufficient to post the load LMPs only for zero service security (i.e. $\rho = 0$) and full service security (i.e., $\rho = 1$). The load LMPs for any other level of service security can then be derived directly by employing the following formula:

$$\boldsymbol{\lambda}_{\boldsymbol{d}}^{(k)} = \boldsymbol{\lambda}_{\boldsymbol{d}}^{(zss)} + \rho_k \left(\boldsymbol{\lambda}_{\boldsymbol{d}}^{(fss)} - \boldsymbol{\lambda}_{\boldsymbol{d}}^{(zss)} \right). \tag{41}$$

Here, $\boldsymbol{\lambda}_{\boldsymbol{d}}^{(zss)}$ and $\boldsymbol{\lambda}_{\boldsymbol{d}}^{(fss)}$ are the load LMP vectors (nodal) corresponding to zero service security and full service security, respectively. The formula shown in (41) is specifically useful to generate clear price signals for the future expansions.

The consideration of a fixed bus voltage profile is not a hard requirement for the implementation of the proposed LMP framework. If required, the market optimization problem can easily be modified by introducing voltage variables along with the associated constraints. This will also not change the LMP expressions. The assumption of a fixed bus voltage profile is made basically to keep the formulation simple especially in the context of LMP decomposition [23]. The inclusion of bus reactive power constraints is also quite straightforward in the case loads are assumed to draw no reactive power from the grid (i.e., the reactive power requirements of the loads are locally fulfilled). However, in the absence of sufficient local reactive power supports for loads, some conservative approach may have to be followed to represent the reactive power compensation limits if reserve services are taken from the demand side. In the case the reactive power constraints are added in the formulation, the loss of reactive power generation will also have to be taken into account along with the loss of active power generation.

By employing the AC power flow relationship, $f_{inj,n}(\boldsymbol{\delta})$ can be expressed as follows:

$$f_{inj,n}(\boldsymbol{\delta}) = \sum_{l=1}^{L} \left\{ \frac{a_{n,l} x_l^2}{r_l^2 + x_l^2} f_{F,l}(\boldsymbol{\delta}) + 0.5 |a_{n,l}| f_{loss,l}(\boldsymbol{\delta}) \right\} \tag{42}$$

where

$$\begin{aligned} a_{n,l} &= 1 \quad \text{if Line } l \text{ is directed away from Bus } n \\ &= -1 \text{ if Line } l \text{ is directed towards Bus } n \\ &= 0 \quad \text{if Line } l \text{ is not incident on Bus } n. \end{aligned} \tag{43}$$

In the case of DCOPF application (which is the most common practice), the linearized expression of $f_{inj,n}(\boldsymbol{\delta})$ can be obtained by linearizing $f_{loss,l}(\boldsymbol{\delta})$ around a base case system state and by replacing $f_{F,l}(\boldsymbol{\delta})$ with its DC power flow expression. The function $f_{inj,n}^{(c)}(\boldsymbol{\delta}^{(c)})$ can be linearized in the same way. The loss linearization to be performed is in line of the loss modeling approach shown in [24]. It is to be noted that the reactive power or variable bus voltage cannot be considered in the DCOPF application.

The market optimization model proposed is always less complex compared to existing ones. This is because of the absence of variables and constraints related to upward reserve bids from loads and downward reserve bids from generators. The expanded SCOPF formulation shown above can also be simplified in many ways. For example, (9) and (11) can be replaced in (15). Similarly, (12) can be replaced in (22) and (15) can be replaced in (23). In addition, if all the reserve types are simultaneously considered for a particular type of contingency, the energy-reserve coupling constraints corresponding to the other contingency types can simply be removed from the formulation. Similarly to [10] and [11], it is also possible to procure reserve services on zonal basis instead of on nodal basis. The zones should be formed across the potentially congested lines and each zone will have to be treated like a single bus for the post-contingency system representation. However, the energy prices will still have to be defined at the nodal level. This is because the pre-contingency scheduling in the SCOPF calculation is carried out at the nodal level only.

IV. LMP Decomposition

The decomposition of load and generator LMP vectors can be performed by following the same procedure as is shown in [25]. According to the KKT necessary conditions of optimality

$$\frac{\partial \Lambda}{\partial \boldsymbol{\delta}'} = -\boldsymbol{\nu}_{\boldsymbol{1}}^{*T} \frac{\partial \boldsymbol{f_{inj}}}{\partial \boldsymbol{\delta}'}(\boldsymbol{\delta}^*) + \boldsymbol{\mu}^{*T} \frac{\partial \boldsymbol{f_{cap}}}{\partial \boldsymbol{\delta}'}(\boldsymbol{\delta}^*) = \boldsymbol{0}_{\boldsymbol{N-1}}^T \tag{44}$$

$$\frac{\partial \Lambda}{\partial P_{slack}} = \boldsymbol{\nu}_{\boldsymbol{1}}^{*T} \boldsymbol{\Omega} + \nu_0^* = 0 \tag{45}$$

where

$$\boldsymbol{\mu} = \begin{bmatrix} \boldsymbol{\mu}_{\boldsymbol{1}}^T & \boldsymbol{\mu}_{\boldsymbol{2}}^T \end{bmatrix}^T \tag{46}$$

$$\boldsymbol{f_{cap}}(\boldsymbol{\delta}) = \begin{bmatrix} \boldsymbol{f_F}(\boldsymbol{\delta})^T & -\boldsymbol{f_F}(\boldsymbol{\delta})^T \end{bmatrix}^T \tag{47}$$

$$\boldsymbol{\delta}' = [\delta_1 \quad \delta_2 \quad \ldots \delta_{N-1}]^T. \tag{48}$$

Here, the Nth bus is taken as the angle reference bus. The relationships shown in (44) and (45) can be compactly written as follows:

$$\boldsymbol{\nu}_{\boldsymbol{1}}^{*T} \underbrace{\begin{bmatrix} \frac{\partial \boldsymbol{f_{inj}}}{\partial \boldsymbol{\delta}'}(\boldsymbol{\delta}^*) & -\boldsymbol{\Omega} \end{bmatrix}}_{\boldsymbol{J}} = \begin{bmatrix} \boldsymbol{\mu}^{*T} \frac{\partial \boldsymbol{f_{cap}}}{\partial \boldsymbol{\delta}'}(\boldsymbol{\delta}^*) & \nu_0^* \end{bmatrix}. \tag{49}$$

Therefore

$$\boldsymbol{\nu}_{\boldsymbol{1}}^{*T} \boldsymbol{J} = \boldsymbol{\mu}^{*T} \begin{bmatrix} \frac{\partial \boldsymbol{f_{cap}}}{\partial \boldsymbol{\delta}'}(\boldsymbol{\delta}^*) & \boldsymbol{0_{2L}} \end{bmatrix} + \nu_0^* \begin{bmatrix} \boldsymbol{0}_{\boldsymbol{N-1}}^T & 1 \end{bmatrix}. \tag{50}$$

The second term on the right hand side of (50) can be decomposed as follows:

$$\begin{bmatrix} \boldsymbol{0}_{\boldsymbol{N-1}}^T & 1 \end{bmatrix} = -\boldsymbol{1}_{\boldsymbol{N}}^T \boldsymbol{J} + \begin{bmatrix} \frac{\partial \left\{ \boldsymbol{1}_{\boldsymbol{N}}^T \boldsymbol{f_{inj}} \right\}}{\partial \boldsymbol{\delta}'}(\boldsymbol{\delta}^*) & 0 \end{bmatrix}. \tag{51}$$

It should be noted that $\boldsymbol{1}_{\boldsymbol{N}}^T \boldsymbol{\Omega} = 1$. Let the matrix $\boldsymbol{S}$ and the vector $\boldsymbol{L}_{\mathbf{F}}$ be defined as follows:

$$\boldsymbol{S} = \begin{bmatrix} \frac{\partial \boldsymbol{f_{cap}}}{\partial \boldsymbol{\delta}'}(\boldsymbol{\delta}^*) & \boldsymbol{0_{2L}} \end{bmatrix} \boldsymbol{J}^{-1} \tag{52}$$

$$\boldsymbol{L}_{\boldsymbol{F}}^T = \begin{bmatrix} \frac{\partial \left\{ \boldsymbol{1}_{\boldsymbol{N}}^T \boldsymbol{f_{inj}} \right\}}{\partial \boldsymbol{\delta}'}(\boldsymbol{\delta}^*) & 0 \end{bmatrix} \boldsymbol{J}^{-1}. \tag{53}$$

Therefore, after replacing (51) into (50), $\boldsymbol{\nu}_1^*$ can be expressed in the following form:

$$\boldsymbol{\nu}_1^* = -\nu_0^* \mathbf{1}_N + \nu_0^* \boldsymbol{L}_F + \boldsymbol{S}^T \boldsymbol{\mu}^*. \tag{54}$$

Subsequently, (54) can be replaced in (39) and (40) to yield the following alternative expressions of the generator and load LMP vectors:

$$\boldsymbol{\lambda}_g = \nu_0^* \mathbf{1}_N - \nu_0^* \boldsymbol{L}_F - \boldsymbol{S}^T \boldsymbol{\mu}^* + \sum_{c=1}^{\varpi} \widehat{\boldsymbol{\beta}}^{(c)^T} \boldsymbol{\mu}_4^{(c)^*} \tag{55}$$

$$\boldsymbol{\lambda}_d^{(k)} = \nu_0^* \mathbf{1}_N - \nu_0^* \boldsymbol{L}_F - \boldsymbol{S}^T \boldsymbol{\mu}^* + \sum_{c=1}^{\varpi} \left\{ \rho_k \boldsymbol{\mu}_4^{(c)^*} - \boldsymbol{\mu}_3^{(c)^*} \right\}. \tag{56}$$

It is obvious that

$$\mathbf{1}_L^T \boldsymbol{f}_{loss}(\boldsymbol{\delta}) = \mathbf{1}_N^T \boldsymbol{f}_{inj}(\boldsymbol{\delta}). \tag{57}$$

Therefore, the elements of the $\boldsymbol{L}_F$ vector are essentially the loss sensitivity factors. In the same way, matrix $\boldsymbol{S}$ defines the sensitivities of line flows to the specified nodal active power injections. The matrix $-\rho_k \boldsymbol{U}_N$ defines the sensitivity of $\overline{\boldsymbol{P}}_{bus}^{(c)}$ to the specified nodal active power loads corresponding to the kth level of service security, and $\widehat{\boldsymbol{\beta}}^{(c)}$ signifies the sensitivity of $\overline{\boldsymbol{P}}_{bus}^{(c)}$ to the specified nodal active power generations. Similarly, the sensitivity of $\underline{\boldsymbol{P}}_{bus}^{(c)}$ to the specified nodal active power loads (for any level of service security) is given by $-\boldsymbol{U}_N$. The decompositions of generator and load LMPs can, therefore, be defined as follows:

$$\boldsymbol{\lambda}_{g,enr} = \boldsymbol{\lambda}_{d,enr}^{(k)} = \nu_0^* \mathbf{1}_N \tag{58}$$

$$\boldsymbol{\lambda}_{g,loss} = \boldsymbol{\lambda}_{d,loss}^{(k)} = -\nu_0^* \boldsymbol{L}_F \tag{59}$$

$$\boldsymbol{\lambda}_{g,con} = -\boldsymbol{S}^T \boldsymbol{\mu}^* + \sum_{c=1}^{\varpi} \widehat{\boldsymbol{\beta}}^{(c)^T} \boldsymbol{\mu}_4^{(c)^*} \tag{60}$$

$$\boldsymbol{\lambda}_{d,con}^{(k)} = -\boldsymbol{S}^T \boldsymbol{\mu}^* - \sum_{c=1}^{\varpi} \left\{ \boldsymbol{\mu}_3^{(c)^*} - \rho_k \boldsymbol{\mu}_4^{(c)^*} \right\}. \tag{61}$$

It can be further shown that

$$\boldsymbol{\lambda}_{d,con}^{(k)} = \boldsymbol{\lambda}_{d,con}^{(zss)} + \rho_k \left(\boldsymbol{\lambda}_d^{(fss)} - \boldsymbol{\lambda}_d^{(zss)} \right). \tag{62}$$

Thus, it is sufficient to post only $\boldsymbol{\lambda}_{g,con}$ and $\boldsymbol{\lambda}_{g,con}^{(zss)}$ to provide complete information about all the congestion prices.

V. FTR Implementation

With the energy price separation taking place at each bus, the definition of FTRs should also be consistently updated. The settlement of an FTR is now to be made according to the difference between the congestion components of the load and generator LMPs at the sink and source locations, respectively. The same is prescribed based upon the consideration that FTRs are basically made for compensating the congestion payments of bilateral transactions. The elementary specifications of an FTR remain the same as before. However, since load LMPs are classified according to service security, there should also be a service security specification for the sink of an FTR.

The settlement of FTRs can be performed by optimally decomposing the LMP vectors [26]. For that, a reference price vector $\boldsymbol{\lambda}_{ref}$ should initially be defined as follows:

$$\boldsymbol{\lambda}_{ref} = -\boldsymbol{S}^T \boldsymbol{\mu}^*. \tag{63}$$

With the same procedure as is followed in [26], $\boldsymbol{\lambda}_{ref}$ can subsequently be expressed in the following form:

$$\boldsymbol{\lambda}_{ref} = \boldsymbol{v}_{ref} \lambda_{ref,N} + \boldsymbol{u}_{ref}. \tag{64}$$

The value of $\boldsymbol{\lambda}_{ref}$ depends upon choice of $\boldsymbol{\Omega}$. It is, however, to be noted that $\boldsymbol{v}_{ref}$ and $\boldsymbol{u}_{ref}$ are always slack independent. The is because the solution of the above OPF problem is in itself slack independent. By replacing (64) in (60) and (61), $\boldsymbol{\lambda}_{g,con}$ and $\boldsymbol{\lambda}_{d,con}^{(k)}$ can also be expressed in terms of $\lambda_{ref,N}$. The optimal LMP decomposition task can subsequently be formulated in the form of a simple quadratic programming problem with only one variable (that is, $\lambda_{ref,N}$) and two constraints. The optimal solution for $\lambda_{ref,N}$ thus obtained can then be substituted in (60) and (61) through (64) to get the optimal solutions for the generator and load congestion prices.

The simultaneous feasibility test (SFT) of FTRs should be performed with the same set of network constraints as is considered in the dispatch scheduling problem. A good estimation of the future unit commitment pattern is required in this regard so as to define a suitable value of $\boldsymbol{P}_{min}^{gen}$. It is, however, essential to ignore active power losses in the network while performing the simultaneous feasibility test. The same is required in order to maintain consistency with the lossless profile of practically used balanced FTRs. At the same time, the reserve variables cannot be considered in SFT. This is because FTRs are never specified at the resource level (i.e., from a particular generator to a particular load). The generator contingency cases are also to be ignored in SFT so as to ensure sufficient issuance of FTRs.

VI. Case Study

Two different case studies are performed. In the first case study, the improvement in bid-consistency is numerically illustrated. The ability of the proposed methodology to improve demand response is verified in the second case study. The base MVA for these studies is taken to be 100. The market optimization is carried out by using the DCOPF formulation. The base case system state for performing loss linearization is established through an initial lossless OPF calculation.

A. Case Study 1: Illustration of Improved Bid-Consistency

Consider the 4-bus and 6-line system shown in Fig. 1. The information of line parameters for the particular system is provided in Table I. There are eight generators in the system. The generator details are provided in Table II. The load entities are indicated by L1, L2, L3, and L4, respectively.

For a particular hour of operation, all the generating units are found to be committed. The energy bids received for the particular hour are shown in Table III. The acronyms "Gen" and

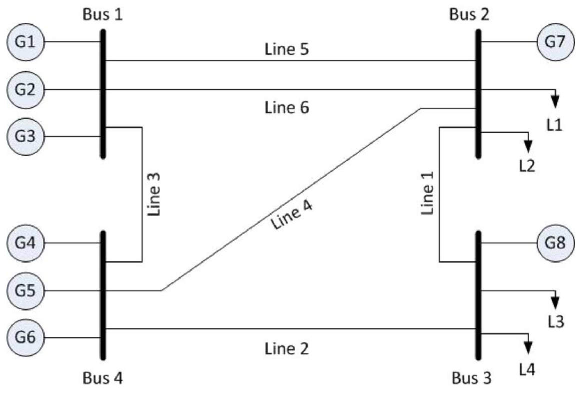

Fig. 1. Sample 4-bus system.

TABLE I
LINE DETAILS (CASE STUDY 1)

Line no.	Reactance (p.u.)	Resistance (p.u.)	Flow limit (MW)
1	0.15	0.015	333
2	0.15	0.015	333
3	0.10	0.01	500
4	0.20	0.02	250
5	0.20	0.02	250
6	0.20	0.02	250

TABLE II
GENERATOR DETAILS (CASE STUDY 1)

Generator id.	Maximum MW	Minimum MW	Ramp rate (MW/min)
G1	240	60	2
G2	240	60	2
G3	240	60	2
G4	155	38.75	1.2917
G5	155	38.75	1.2917
G6	155	38.75	1.2917
G7	35	8.75	0.2917
G8	35	8.75	0.2917

"Trans" stand for "Generator" and "Bilateral Transaction", respectively. There are also some self-scheduled requests, which are shown in Table IV. Note that the minimum generation limits of G7 and G8 are taken into account in the form of self-scheduled requests.

The particular case study is performed by considering two single and one double contingency cases as are shown in Table V. The target recovery times for the single and double contingencies are specified to be 10 min and 30 min, respectively. The outage of Generator G1 is modeled by assuming 20% loss of the total generation schedule as well as 20% loss of the total reserve schedule (i.e., $\alpha_{G1} = \gamma_{G1} = 0.2$). The upward reserve bids that are received from generators for the particular hour are shown in Table VI. The response times of spinning and operating reserves are specified to be 10-min and 20-min, respectively. The spinning reserve is to be used both for single and double contingencies, whereas, the operating reserve is to be used only for the double contingency. The elements of the fourth column of Table VI are obtained by multiplying the ramp rates of the respective generators with the corresponding reserve response times.

TABLE III
ENERGY BID INFORMATION (CASE STUDY 1)

Bid id.	Type	Entity	MW amount	Bid price ($/MW)	Service security
GB1	Gen	G1	90	22	–
GB2	Gen	G2	140	19	–
GB3	Gen	G3	102.50	20	–
GB4	Gen	G4	67.50	25	–
GB5	Gen	G5	105	24	–
GB6	Gen	G6	80	22	–
GB7	Gen	G7	26.25	24	–
GB8	Gen	G8	26.25	24	–
LB1	Load	L1	25	30	0.73
LB2	Load	L2	30	32	0.73
LB3	Load	L3	100	28	0.73
LB4	Load	L4	62.50	26	0.73
TB1	Trans	(G1, L3)	50	6.10	0.78
TB2	Trans	(G2, L1)	12.50	6.27	0.78
TB3	Trans	(G3, L4)	25	5.50	0.78
TB4	Trans	(G4, L2)	12.50	4	0.78
TB5	Trans	(G5, L3)	12.50	4.50	0.78
TB6	Trans	(G6, L4)	25	5	0.78

TABLE IV
SELF-SCHEDULE INFORMATION (CASE STUDY 1)

Self-schedule id.	Type	Entity	MW amount	Service security
SSG1	Gen	G7	8.75	–
SSG2	Gen	G8	8.75	–
SSL1	Load	L1	25	0.80
SSL2	Load	L2	20	0.80
SSL3	Load	L3	87.50	0.80
SSL4	Load	L4	112.50	0.80
SSBT1	Trans	(G1, L3)	100	0.83
SSBT2	Trans	(G2, L1)	87.50	0.83
SSBT3	Trans	(G3, L4)	112.50	0.83
SSBT4	Trans	(G4, L2)	75	0.83
SSBT5	Trans	(G5, L3)	37.50	0.83
SSBT6	Trans	(G6, L4)	50	0.83

TABLE V
CONTINGENCY INFORMATION (CASE STUDY 1)

Contingency id.	Type	Description
C_1_1	Single	Outage of Line 5
C_1_2	Single	Outage of Generator G1
C_1_3	Double	Outages of both Line 5 and Generator G1

The optimal power flow problem is solved by using the GAMS software. The market clearing results that are obtained for energy and reserved bids in the proposed approach are shown in Tables VII and VIII, respectively. It can be easily seen that there is perfect bid-consistency in the load prices. That is, the price charged to any selected load bid is no higher than its quoted price. At the same time, the price charged to LB3 is exactly equal to its quoted price because of its partial selection. For LB4, the concerned entity sees a market price that is higher than its quoted price. This justifies the rejection of the particular load bid. There is also no instance of underpayment or overcharge for the generation and bilateral transaction bids. The prices that are established for generators and bilateral transactions are eventually found to be perfectly bid-consistent for this particular case. However, the perfect bid-consistency of the prices established for generators and bilateral transactions can not always be ensured. In the case

TABLE VI
UPWARD RESERVE BIDS FROM GENERATORS (CASE STUDY 1)

Bid id.	Type	Entity	MW amount	Bid price ($/MW)
RSPB1	Spinning	G1	20	2.20
RSPB2	Spinning	G2	20	1.90
RSPB3	Spinning	G3	20	2
RSPB4	Spinning	G4	12.917	2.50
RSPB5	Spinning	G5	12.917	2.40
RSPB6	Spinning	G6	12.917	2.20
RSPB7	Spinning	G7	2.917	2.40
RSPB8	Spinning	G8	2.917	2.40
ROPB1	Operating	G1	40	0.22
ROPB2	Operating	G2	40	0.19
ROPB3	Operating	G3	40	0.20
ROPB4	Operating	G4	25.834	0.25
ROPB5	Operating	G5	25.834	0.24
ROPB6	Operating	G6	25.834	0.22
ROPB7	Operating	G7	5.834	0.24
ROPB8	Operating	G8	5.834	0.24

TABLE VII
MARKET CLEARING RESULTS FOR ENERGY BIDS IN THE PROPOSED APPROACH (CASE STUDY 1)

Bid id.	Cleared amount (MW)	Clearing price ($/MW)	Bid id.	Cleared amount (MW)	Clearing price ($/MW)
GB1	0	21.9144	LB2	30	24.3615
GB2	140	21.9144	LB3	47.32	28
GB3	102.50	21.9144	LB4	0	28
GB4	0	22.4313	TB1	39.53	6.10
GB5	0	22.4313	TB2	12.50	2.4609
GB6	80	22.4313	TB3	0	6.10
GB7	26.25	24.3856	TB4	12.50	1.944
GB8	26.25	28.0276	TB5	0	5.5831
LB1	25	24.3615	TB6	0	5.5831

TABLE VIII
MARKET CLEARING RESULTS FOR RESERVE BIDS IN THE PROPOSED APPROACH (CASE STUDY 1)

Bid id.	Cleared amount (MW)	Clearing price ($/MW)	Bid id.	Cleared amount (MW)	Clearing price ($/MW)
RSPB1	0	0.20	ROPB1	0	0.20
RSPB2	0	0.20	ROPB2	0	0.20
RSPB3	0	0.20	ROPB3	2.58	0.20
RSPB4	0	0.2125	ROPB4	0	0.2125
RSPB5	0	0.2125	ROPB5	0	0.2125
RSPB6	0	0.2125	ROPB6	0	0.2125
RSPB7	0	0.2243	ROPB7	0	0.2243
RSPB8	0	0.2373	ROPB8	0	0.2373

some of the energy-reserve coupling constraints become active, a partially selected generation bid may be paid more and a partially selected bilateral transaction bid may be charged less than the quoted price.

Another market simulation is carried out by considering separate reserve bids from the load entities. The upward reserve bids that are received from the load entities are shown in Table IX. In the case of loads, there may not be any ramp rate burden. Therefore, no upper limit is to be separately specified for the upward reserve bid from a load entity. The minimum MW to be served for a load entity is set equal to its total self-scheduled quantity (as per the load and bilateral transaction requests).

TABLE IX
UPWARD RESERVE BIDS FROM LOAD ENTITIES (CASE STUDY 1)

Bid id.	Type	Entity	MW amount	Bid price ($/MW)
RSPB9	Spinning	L1	–	3
RSPB10	Spinning	L2	–	3.20
RSPB11	Spinning	L3	–	2.80
RSPB12	Spinning	L4	–	2.60
ROPB9	Operating	L1	–	0.30
ROPB10	Operating	L2	–	0.32
ROPB11	Operating	L3	–	0.28
ROPB12	Operating	L4	–	0.26

TABLE X
MARKET CLEARING RESULTS FOR ENERGY BIDS IN THE CONVENTIONAL APPROACH (CASE STUDY 1)

Bid id.	Cleared amount (MW)	Clearing price ($/MW)	Bid id.	Cleared amount (MW)	Clearing price ($/MW)
GB1	0	21.90	LB2	30	25.1144
GB2	140	21.90	LB3	47.37	28.608
GB3	102.50	21.90	LB4	0	28.608
GB4	0	22.4312	TB1	39.47	6.708
GB5	0	22.4312	TB2	12.50	3.2144
GB6	80	22.4312	TB3	0	6.708
GB7	26.25	24.3788	TB4	12.50	2.6832
GB8	26.25	27.8724	TB5	0	6.1768
LB1	25	25.1144	TB6	0	6.1768

TABLE XI
MARKET CLEARING RESULTS FOR RESERVE BIDS IN THE CONVENTIONAL APPROACH (CASE STUDY 1)

Bid id.	Cleared amount (MW)	Clearing price ($/MW)	Bid id.	Cleared amount (MW)	Clearing price ($/MW)
RSPB1	20	2.9423	ROPB1	0	0.2075
RSPB2	0	2.9423	ROPB2	0	0.2075
RSPB3	20	2.9423	ROPB3	5	0.2075
RSPB4	12.92	3.0665	ROPB4	0	0.22
RSPB5	12.92	3.0665	ROPB5	0	0.22
RSPB6	12.92	3.0665	ROPB6	3.29	0.22
RSPB7	0	3.20	ROPB7	0	0.2342
RSPB8	0	3.408	ROPB8	0	0.2468
RSPB9	37.50	3.20	ROPB9	0	0.2342
RSPB10	6.95	3.20	ROPB10	0	0.2342
RSPB11	86.84	3.408	ROPB11	0	0.2468
RSPB12	0	3.408	ROPB12	0	0.2468

The market clearing results for energy and reserve bids for the particular simulation are shown in Tables X and XI, respectively. Unlike [10] and [11], the generator LMPs are still different from the load LMPs. The same has happened since the loss of generation is modeled in percentage term and the ramp down limits of generators are ignored. In the case the loss of generation is modeled in MW and the ramp down limits of generators are enforced, there will be a unique energy LMP vector both for loads and generators. It is interesting to observe that the prices charged to LB3 and TB1 are higher than the respective bid prices. In the case TB1 is submitted by L3 itself, there will, however, be perfect compensation for the above monetary loss through the addition payment that is received for RSPB11. On the other hand, if G1 is responsible for TB1, it will suffer from a net monetary loss of $9.15 (after considering all the energy and reserve payments). There may also be a third party trader

TABLE XII
CONTINGENCY INFORMATION (CASE STUDY 2)

Contingency id.	Type	Description
C_2_1	Single	Outage of Line 128
C_2_2	Single	Outage of Line 45
C_2_3	Single	Outage of Generator 27
C_2_4	Single	Outage of Generator 4
C_2_5	Single	Outage of Generator 45
C_2_6	Double	Outages of both Line 128 Generator 27
C_2_7	Double	Outages of both Line 45 Generator 4
C_2_8	Double	Outages of both Line 128 Generator 4
C_2_9	Double	Outages of both Line 45 Generator 27
C_2_10	Double	Outages of both Line 128 Generator 45

who is responsible for TB1. In that case, the respective trader will see a net monetary loss of \$24. The higher monetary loss happens since there cannot be any reserve offer from a trader. Therefore, the trader will not be able to get the above monetary loss compensated with the surplus reserve payment.

B. Case Study 2: Illustration of Improved Demand Response

The particular case study is performed on the IEEE 118-bus system. The generator, load and transmission line data of the IEEE 118-bus system are provided in [27]. For the sake of simplicity, however, the minimum MW limits of the generators are set to zero. The price quoted by a generator in the energy bid is equal to its marginal cost of production. The full generation capacities are offered in the energy bids. All the load requests are assumed to be made at a very high bid price of \$100/MW. No bilateral transaction is considered for this case study.

The different contingency events that are considered for this case study are shown in Table XII. The contingency and reserve types as well as their associations are defined as before. The price quoted for a spinning reserve bid is equal to one-tenth of the marginal cost of production of the respective generator at the upper MW limit. The price quoted for an operating reserve bid is equal to one-tenth of the price quoted for the corresponding spinning reserve bid. The values of α and γ for a generator are obtained as follows:

$$\alpha = \frac{\text{Capacity of the generator}}{\text{Total load request}} \tag{65}$$

$$\gamma = \frac{\text{Capacity of the generator}}{\text{Total installed generation capacity}}. \tag{66}$$

Fig. 2 shows the load percentages that remain unserved for the different levels of demand response. The demand response is quantified by the reserve percentage of a load schedule. Here all the loads are assumed to respond at the same level (i.e., with the same reserve percentage). It can be seen that around 3.8% of the total load request cannot be served if there is no demand response. However, as the demand response grows, the unserved load quantity quickly comes down. For the case studied, all the load requests can be fully served when the reserve percentage of a load schedule grows beyond 6.825%.

It is obvious that there is additional stress on the system because of security constraints when the demand response is at a poor level. This in turn makes some portion of the load requests remain unselected although the load entities are ready to pay very high prices. The need for more reserve services from the demand side to alleviate security constraints can be easily interpreted from the load LMP split that occurs in the proposed methodology. Fig. 3 shows the LMP split that occurs at Bus 1 for the different levels of demand response. The heavy solid and broken curves in Fig. 3 represent the load LMP values at Bus 1 corresponding to full service security and zero service security, respectively. The indication of system stress thus received makes a load entity clearly see the opportunity of getting more power by providing more reserve service. The stress on the system due to security constraints exists even after the full satisfaction of load requests. Therefore, the LMP split continues for some time further beyond the reserve percentage of 6.825%. The load entities can then see the opportunity to pay lower prices by further increasing their reserve services. The variation of the price that is charged to the load entity at Bus 1 for its different levels of reserve response is shown through the normal solid curve in Fig. 3.

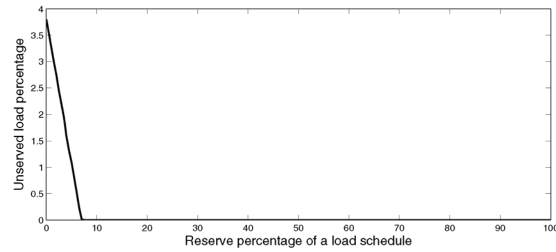

Fig. 2. Unserved load percentage versus demand response.

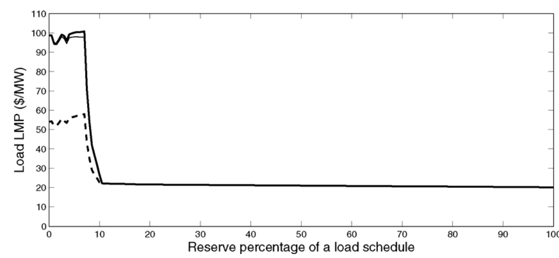

Fig. 3. Load LMP variation at Bus 1 with growing demand response.

In the case of uniform locational marginal pricing, no clear hint is obtained about the requirement of more reserve services. Although it is possible to define generator and load LMPs separately with explicit demand side reserve bidding (as in Case Study 1), the same does not provide any useful information for the load entities. This is because such an LMP separation can take place even for the activation of (22) for which the reserve services provided by load entities have no role to play.

VII. CONCLUSION

The operation of a power system should be secured enough against the contingencies so as to prevent the massive loss of national economy and the disruption of the rhythm of normal life. However, the economy of the normal power system operation gets affected because of the security restriction. The demand response to provide reserve services has a vital role to play to restore the economy of the system operation for the security-constrained market optimization. In order to assist the growth of the respective demand response, it is required to provide clear indication of the additional system stress induced by the security constraints. For the conventional reserve bidding approaches, no such indication is obtained because of uniform locational marginal pricing. Therefore, a new format of demand side participation in the security program is designed in this paper by employing a concept of load service security. Different prices are defined for different levels of service security. The load price separation that takes place at a bus clearly signals the statuses of security constraints. Only upward reserve services are considered from the load entities, whereas both upward and downward reserve services are considered from the generating entities. The prices that are established for the load entities are found to be perfectly bid-consistent. The perfect bid-consistency could not be achieved for the prices that are established for generators and bilateral transactions. However, the issues of overcharges to bilateral transactions and underpayments to generators are resolved. The price split that takes place in the proposed methodology is well-characterized to provide clear price signals for future investments. The implementation of FTRs is also discussed for the proposed pricing framework.

For the market optimization framework proposed, one critical assumption is that the ramp down limits of generators can be ignored. It is, however, not difficult to extend the formulation by considering the ramp down limits (in the case, say, the use of a bypass valve is restricted only to the full load relief). The ramp down limits can be taken into account in the same way as the ramp up limits are considered. In the case it is essential to consider the ramp-down limits, there may not be any improvement in the bid-consistency of the prices established for generation and bilateral transaction bids. However, the perfect bid-consistency of load prices will still exist. At the same time, the price signals will be generated as before to assist the growth of demand response towards the system security.

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