Locational balance service auction market for transmission congestion management

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Abstract: A novel market design is proposed and developed that uses the energy-balance services for transmission-congestion relief. In this proposed market, all generators and customers have the ability to submit their offers to increase/decrease their generation/consumption, respectively. Each participant provides a 'price–quantity' offer to the independent system operator (ISO) which is independent of the energy market and is activated after the energy market is settled. The ISO arrives at the optimal procurement of the balancing services for congestion management based on the 'importance' of each market participant to transmission congestion relief using the concept of 'line specific' generalised generation-distribution factors.

List of symbols and abbreviations

i, j, k	index for buses
a_0, b_0, a, b, c	scalar multipliers
BSAM	balance service auction market
CR	congestion redispatch
EM	energy market
FTR	financial transmission right
GGDF	generalised generation distribution factors
ISO	independent system operator
LMP	locational marginal price, \$/MWh
LSF	load scaling factor
MD	market dispatch
N_G	total number of generator buses
N_L	total number of load buses
N_T	total number of transmission lines
OPF	optimal power flow
P_D	real power demand, p.u.
P_G	real power generation, p.u.
P_{G°	real power generation after market settlement, p.u.
P_G^{max}	upper limit on real power generation, p.u.
P_G^{min}	lower limit on real power generation, p.u.
P_{ij}	power flow on line i-j, p.u.
P_{ij}^{max}	maximum transfer capacity of line i-j, p.u.
Q_D	reactive power demand, p.u.
Q_G	reactive power generation, p.u.
Q_C	reactive power compensation, p.u.
Q_C^{max}	upper limit on reactive-power compensation, p.u.
Q_C^{min}	lower limit on reactive-power compensation, p.u.
TCS	total cost of service, \$
V	bus voltage, p.u.
V^{max}	upper limit on bus voltage, p.u.
V^{min}	lower limit on bus voltage, p.u.
Y_{ij}	element of network admittance matrix, p.u.
θ	angle associated with Y_{ij}, rad
δ	voltage angle, rad
$P_{inj,k}$	injected power at bus k, p.u.
$D_{ij,k}$	generalised generation-distribution factors
P_G^+	up-regulation of generation, p.u.
P_G^-	down-regulation of generation, p.u
P_D^+	up-regulation of load, p.u.
P_D^-	down-regulation of load, p.u.
C_G^+	up-regulation offer price from a generator, \$/MWh
C_G^-	down-regulation offer price from a generator, \$/MWh
C_d^+	up-regulation offer price from a load, \$/MWh
C_d^-	down-regulation offer price from a load, \$/MWh
ρ_{PG}^+	up-regulation market price for generators, \$/MWh
ρ_{PG}^-	down-regulation market price for generators, \$/MWh
ρ_{PD}^+	up-regulation market price for loads, \$/MWh
ρ_{PD}^-	down-regulation market price for loads, \$/MWh

1 Introduction

In the erstwhile vertically integrated utility structure, all entities such as generation, transmission and distribution were within the domain of a central energy management system. Generation was dispatched in order to achieve the least-cost operation of the system. In such systems, transmission congestion management was usually taken care of by determining the optimal dispatch solution using a model similar to the optimal power flow (OPF) or a security constrained economic dispatch problem. This, effectively, meant that a generation pattern was determined such that the power flow limits on the transmission lines

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were not exceeded. The presence of transmission line capacity constraints in such scheduling programs resulted in higher marginal cost and reduced revenue for the utility which, in turn, acted as a signal to the utility. A persistent congestion problem was an indication to install new generation capacity or to build additional transmission facilities.

Apart from alleviating transmission congestion through the dispatch and scheduling process, other methods such as operation of transformer taps, outage of the congested line and operation of FACTS devices have also been proposed in the literature.

1.1 Congestion management in deregulation

In the context of operating the power systems in a deregulated environment, several methods have been proposed by researchers to address the congestion management problem such as security-constrained generation redispatch, zonal/cluster-based management, network sensitivity-factor-based method, demand-response ancillary services, financial transmission rights (FTRs), congestion pricing and market-based methods and using FACTS devices [1].

A unified framework for solving the market dispatch and generation-redispatch problem from the perspective of the independent system operator (ISO) was developed in [2]. An optimisation procedure for redispatch of generation was proposed in [3] to alleviate transmission congestion on the network. Consequently, a new approach to allocate the cost of congestion and losses to the buses of the transmission system based on the responsibility of the bus was proposed. A 'minimum-distance' generation redispatch was suggested in [4] where the economic value of the transaction adjustment was disregarded.

An optimisation method to analyse the hourly transmission overloads in the Spanish power system, after the electricity market was cleared, was proposed in [5]. Transmission congestion in the Spanish electricity market could be removed by increasing and decreasing the generation output of appropriate connected units, and by connecting off-line generators.

A system of advanced analytical methods and tools for secure and efficient operation of power systems in emerging energy markets was proposed in [6]. For this purpose, the concept of the ISO as a 'generic' operator of an open-access transmission system was defined. The functions of the ISO, which are essential for the security and efficiency of power-system operation, can be identified so as to enable the ISO to perform the bulk of these functions.

An OPF model characterised by the introduction of a two-sided auction with demand elasticity, while taking into account the network constraints, was proposed in [7]. In the proposed market, the ISO had additional degrees of freedom in managing congestion because load demand was a variable. It was shown that the OPF based on a two-sided auction-reduced nodal price volatility and congestion.

In [8], price (marginal-cost) signals were used for generators to manage congestion and the solution under the assumption of rational behaviour was found to be identical to an OPF solution. A similar approach was suggested for the pool model in [9], where the cost of congestion was bundled with the marginal cost at each bus. A bilateral model was also investigated, and a congestion-cost-minimisation approach was proposed.

A framework for real-time congestion management in a market similar to the new trading arrangement of the UK was presented in [10], where resources in the balancing market, as well as some bilateral contracts, were dispatched if necessary. A linearised and modified OPF was proposed to implement the framework. Service identification and congestion management are important functions of the ISO in maintaining system security and reliability. In [11], a combined framework for service identification and congestion management was proposed using the objective of maximising the overall profit of all market participants.

Among other methods for congestion management that have proved to be efficient are the use of network-sensitivity factors, which is the relationship between the change in power injection and the change in power flow in the network [12], [13], [14]. In [12] a zonal/cluster-based congestion-management approach was proposed. The zones were determined from real and reactive power-flow-sensitivity indexes. In [13], the contribution of each generator to power flows, loads and losses in a power system were examined.

1.2 The present work

In the present work, a novel modelling framework is proposed that uses the energy balance service market for transmission-congestion relief. This market, operating after the settlement of the energy market, allows all generators and customers to submit their offers to increase ('up-regulation') or decrease ('down-regulation') their generation/consumption, respectively. Each participant provides a 'price–quantity' offer to the ISO. This work falls within the unified congestion-management framework proposed in [2], wherein the first step involves market dispatch (MD) and is followed by the second step of congestion redispatch (CR).

A somewhat similar market (known as the energy-balance market) is found in Sweden and the UK. The mechanism of 'counter trading' for alleviating transmission congestion in Sweden is an example where such balance services are in use. However, the main difference between 'counter trading' and the proposed market is the introduction of the concept of 'location', in the energy-balance services, which so far has been ignored.

In this proposed market, the auction is settled by the ISO which determines the 'importance' of each participant based on its contribution to transmission congestion relief. Taking that into account, and the participant's offer price, the ISO arrives at the optimal procurement of the location-based energy-balance service for congestion management.

2 Proposed framework

The proposed framework for transmission-congestion management using locational balance services works in the following stages:

(*a*) The first stage is the energy market (EM) settlement by a market operator and is external to the proposed balance market and hence both bilateral contract markets and pool-based energy markets can be accounted for, without any loss of generality. In this study, a pool-type auction model is considered for EM, as described later.

(*b*) After the EM is settled, the ISO is informed of all the transactions in the system and, based on this information, a load flow is executed to determine the system operating status for such a market topology. Line flows are calculated and, consequently, the congested lines are identified.

(*c*) For each congested line, the corresponding generalised generation-distribution factors (GGDFs) are calculated (see Appendix, Section 7). The GGDFs indicate the significance of each bus injection on a particular congested line.

(*d*) In the final stage, the balance service auction market (BSAM) model is executed to determine appropriate selections of locational-balance services to alleviate transmission congestions.

Figure 1 shows the flow chart of the proposed congestion-management scheme using locational-balance services.

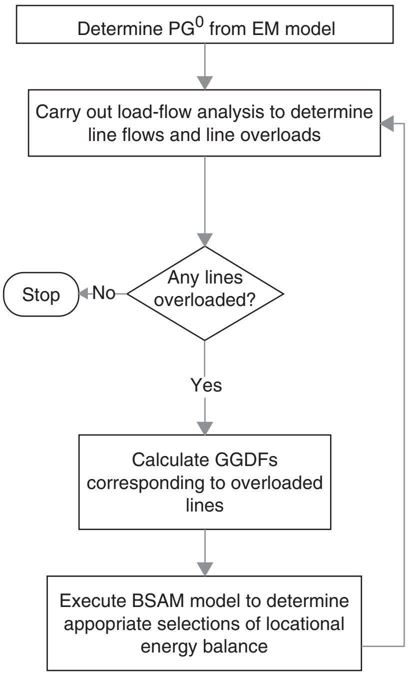

Fig. 1 *Flowchart describing proposed congestion-management scheme*

2.1 Energy-market (EM) model

In this work, we consider a locational marginal price (LMP)-based energy market settlement assuming that the bidding is from the generator side only, and not considering transmission constraints at this stage. The model can easily be extended to include demand-side bidding without any loss of generality. The market settlement objective function is similar to the classical least-cost objective, under the assumption that all generators offer their true costs and that the market is perfect. Accordingly, the objective function J is given by:

$$J = \sum_{i=1}^{NG} a_i P_{G_i}^2 + b_i P_{G_i} + c_i \tag{1}$$

The operational constraints are defined below:

(i) *Real and reactive power balance at each node*: These are the classical real and reactive power-flow equations.

$$P_{G_i}^o - P_{D_i} = \sum_j |V_i||V_j|Y_{ij}\cos(\theta_{ij} + \delta_j - \delta_i) \tag{2}$$

$$Q_{G_i} - Q_{D_i} + Q_{C_i} = -\sum_j |V_i||V_j|Y_{ij}\sin(\theta_{ij} + \delta_j - \delta_i) \tag{3}$$

(ii) *Upper and lower limits on real and reactive power generation*:

$$\begin{aligned} P_{G_i}^{min} &\le P_{G_i}^o \le P_{G_i}^{max} \quad \forall\, i = 1, \ldots, N_G \\ Q_{G_i}^{min} &\le Q_{G_i} \le Q_{G_i}^{max} \quad \forall\, i = 1, \ldots, N_G \end{aligned} \tag{4}$$

(iii) *Upper and lower limits on buses voltages*:

$$\begin{aligned} |V_i| &= \text{constant} \quad \forall\, i = 1, \ldots, N_G \\ V_i^{min} \le |V_i| &\le V_i^{max} \quad \forall\, i = 1, \ldots, N_L \end{aligned} \tag{5}$$

(iv) *Upper and lower limits on reactive power support*:

$$QC_i^{min} \le |QC_i| \le QC_i^{max}, \quad \forall\, i = 1, \ldots, N_L \tag{6}$$

2.2 Balance service auction market (BSAM) model for transmission congestion management

Once the transmission unconstrained EM is settled, the ISO carries out power flow calculations to determine the line overloads based on the cleared generation and loads. If transmission congestion is found to exist on a particular line, or a set of lines, the ISO determines the GGDFs 'corresponding' to these lines only, and thereafter invokes the balance service market to determine the optimal procurement of balance services.

The BSAM model seeks to minimise the (weighted) total cost of services (TCS), for the ISO, i.e. the total payment for the ISO to procure the balance services. The model is explained below:

(i) *Objective function*: The TCS, which is the proposed objective function for minimisation, is defined as the 'weighted' sum of costs for the balance services:

$$J = \sum_{i,j,k} \frac{\left(C_{g_k}^+ P_{G_k}^+ + C_{G_k}^- P_{G_k}^- + C_{d_k}^+ P_{D_k}^+ + C_{G_k}^- P_{D_k}^-\right)}{D_{ij,k}} \quad \forall D_{ij,k} \ne 0 \tag{7}$$

In (7), each component of the bid price is 'weighted' by an appropriate GGDF so as to take into account the 'worth' of the service, as characterised by its location. For example, a low value of $D_{ij,k}$ implies that the real power injection from a bus k has a low impact on the power flow on line *i-j* and bus k may be referred to be located in an unfavourable zone, and its bid price is proportionally scaled up. On the other hand, for a high value of $D_{ij,k}$ the bid price will be proportionally scaled down, bus k being from a 'favourable zone'. Note that the concept of 'favourable' or 'unfavourable' zone is from the perspective of the ISO. As an example, consider the power flow on a line *i-j* which is represented in terms of the GGDFs and two bus injections P_1 and P_2. Let the GGDF of bus 1 be 0.0003 and that of bus 2 be 0.9. Then we can write

$$P_{ij} = 0.0003P_1 + 0.9P_2$$

From the perspective of the ISO, bus 2 is 'favourable' because it has a large impact on the power flow on line *i-j*. Now if the generator at bus 1 offers a very low price, the ISO will have to buy its service, if GGDF was not considered, although it will help very little in relieving congestion. Therefore, from the ISO's perspective, generator 1 has to be penalised so that it is not selected by the optimisation algorithm by virtue of a low offer price. That is why GGDF is incorporated in the objective function.

Such a novel formulation therefore eliminates the possibilities of gaming by generators which are located at unfavourable zones and offer low service prices. However, one important aspect to be noted relates to the compensation principles adopted by the ISO for the BSAM market participants. The BSAM model assumes that the ISO's compensation scheme is based on marginal price (i.e. price of the highest/lowest) accepted up/down regulation bid/offer, although that is not analysed in this work. However, if the ISO uses a 'pay-as-bid' scheme for compensation, the GGDFs should not be included in the objective function.

The operational constraints are as follows:

(i) *Real and reactive power balance at each node*: The power-flow equations are now modified to include both up- and down-regulation services from the generators as well as customers, as variables.

$$P^o_{G_i} - P_{D_i} + P^+_{G_i} - P^-_{G_i} + P^-_{D_i} - P^+_{D_i} = \sum_j |V_i||V_j|Y_{ij}\cos\left(\theta_{ij} + \delta_j - \delta_i\right) \quad (8)$$

$$Q_{G_i} - Q_{D_i} + Q_{C_i} = -\sum_j |V_i||V_j|Y_{ij}\sin\left(\theta_{ij} + \delta_j - \delta_i\right) \quad (9)$$

(ii) *Transmission constraint*: The transmission constraints are modeled using GGDFs, as detailed in the Appendix (Section 7), which is a linear function of the bus injections.

In this work, the above concept has been extended by considering the injected power at all buses. For example, a high value for $D_{1\text{-}8,5}$ indicates that the power injection at bus '5' would significantly affect the power flow on line 1–8. Now if bus 5 is a generator bus, the power injection at this bus can be controlled by changing the generator output. On the other hand, if bus 5 is a load bus, appropriate load changes can bring about the same effect.

It can also be inferred from the high value of $D_{1\text{-}8,5}$ that bus 5 is located in a 'favourable zone', as far as congestion management of line 1–8 is concerned. In the same manner, we can also identify 'unfavourable zones' for congestion management of line 1–8, by identifying low values of $D_{1\text{-}8,k}$.

Such a constraint modelled using the GGDFs is much simpler to handle computationally, than the actual line-flow relationships which are otherwise highly nonlinear functions of voltages and angles, and often pose a severe restriction on the solvability of the model.

$$-P^{max}_{ij} \le \sum_k D_{ij,k} \cdot P_{inj,k} \le P^{max}_{ij} \quad (10)$$

(iii) *Power injected at a bus k*:

$$P_{inj,k} = P^o_{G_k} - P_{D_k} + P^+_{G_k} - P^-_{G_k} + P^-_{D_k} - P^+_{D_k} \quad (11)$$

(iv) *Limit on energy balance*: The upper limit on energy-balance from the generators is effectively determined by the maximum capacity of the generator and the scheduled generation at an hour. A simplistic assumption is made that this entire spinning capacity of the generator is available as energy balance service. In real markets, a part of this would be used as spinning reserve service, and can be appropriately taken into account without difficulty.

The upper limit on the energy balance service from customers is determined by the scalar multipliers a_o and b_o which provide for a proportion of the load offered for balance services:

$$\begin{aligned} 0 &\le P^+_{G_i} \le P^{max}_{G_i} - P^o_{G_i} \\ 0 &\le P^-_{G_i} \le P^o_{G_i} - P^{min}_{G_i} \\ 0 &\le P^+_{D_i} \le a_o P_{D_i} \\ 0 &\le P^-_{D_i} \le b_o P_{D_i} \end{aligned} \quad (12)$$

(v) *Other operational constraints*
In addition to the above, the bus voltage limits (5) and the upper and lower limits on reactive power support (6) are also considered.

(vi) *Uniform price determination*: The uniform prices for up- and down-regulation balance services from generators and customers are determined separately, from the highest accepted offer price in each category.

$$\begin{aligned} \rho^+_{PG} &\ge C^+_{g_k} \quad \forall\, k = 1,\ldots,N_G \\ \rho^-_{PG} &\ge C^-_{g_k} \quad \forall\, k = 1,\ldots,N_G \\ \rho^+_{PD} &\ge C^+_{d_k} \quad \forall\, k = 1,\ldots,N_L \\ \rho^-_{PG} &\ge C^-_{d_k} \quad \forall\, k = 1,\ldots,N_L \end{aligned} \quad (13)$$

Note that the proposed BSAM model described by (7)–(13) is a special case of the unified congestion management framework presented in [2], with particular reference to the congestion-redispatch (CR) model described therein. The present objective function (7) is a special case of the objective function R1 in [2]. Cost components of generators and loads in (7) are separated as up- and down-regulation bids/offers and weighted with the appropriate GGDF to account for their effect of location. Further, the CR model in [2] is an incremental model that uses incremental flows and incremental generation/demand changes while the proposed BSAM model makes use of the injected power and GGDF to determine the line power flows.

3 Analysis

The well known IEEE 30-bus system has been considered for the present studies.

3.1 Base case analysis

The transmission unconstrained EM settlement is carried out based on the offer-price quotes received from generators, and using the model described by (1)–(6). For the purpose of analysis, several load scenarios have been constructed using a load-scaling factor (LSF) that scales both the real and reactive power demands, at all buses in the system, uniformly.

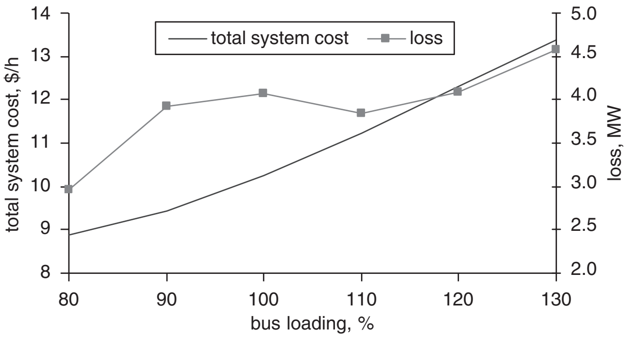

Fig. 2 *Variation of total system cost and transmission-line loss with bus loading*

Figure 2 shows the variation of total system cost and losses as LSF is increased over a range from 80% of base load to 130%. As the bus load is increased, both system cost and the losses increase, as shown in Fig. 2. Note that the total system cost for the transmission-unconstrained EM model is the total cost of generation only.

Figure 3 shows the variation of LMP at generator buses as LSF is increased. It is observed that LMP increase significantly when the system loading is 100% or more.

3.2 Transmission congestion management under normal conditions

Here we examine the role and the performance of energy-balance services in transmission congestion management using the model described in Section 3.2. Figure 4 shows the

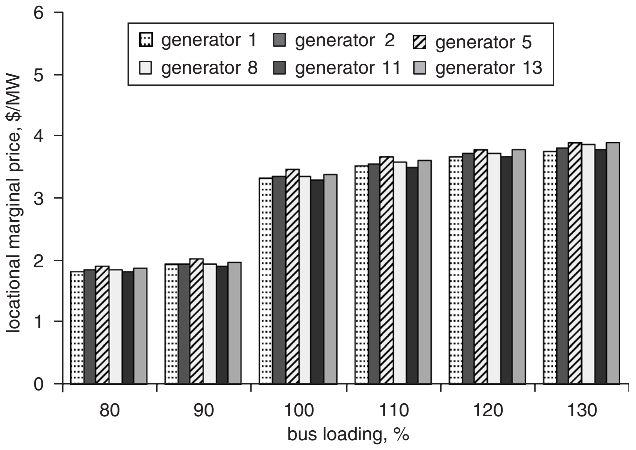

Fig. 3 *LMP at generator buses, as affected by bus loading*

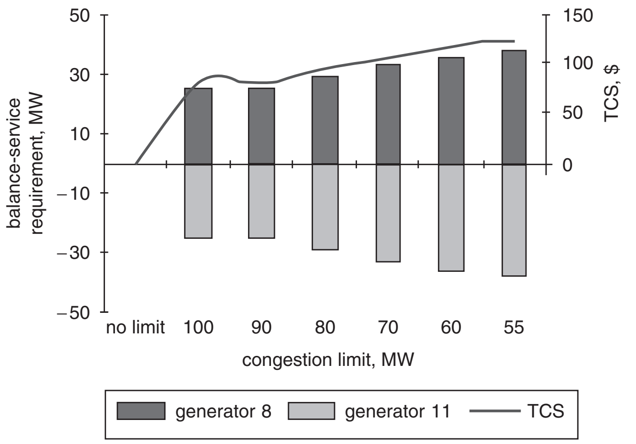

Fig. 4 *Bus-wise balance service procured by ISO for various congestion limits (LSF = 100%)*

amount of energy-balance services invoked by the ISO and the corresponding TCS incurred by it in procuring the services, considering an LSF = 100%, for various transmission capacity availability (or congestion limit).

It is observed from Fig. 4 that, understandably, when there is no limit on transmission capacity the ISO does not purchase any balance service, but when a congestion limit of 100 MW is imposed, it has to procure both up- and down-regulation services. Note also that all these regulation services are procured, bus-specific (in this case at generator buses 8 and 11). It is also observed that when the congestion limit is gradually reduced, i.e. the transmission constraints are further tightened, the ISO is required to procure more energy-balance services and the TCS increases.

Subsequently, the LSF is increased to 130%, i.e. all bus loads are uniformly increased by 1.3 times their base loading. It is observed in Fig. 5 that the ISO is required to procure much more balance services than the previous case and also requires some down-regulation from customers. The TCS is significantly higher in this case, particularly when the congestion limit is 60 MW or less.

Further, the LMPs are calculated at all generator buses for a typical LSF = 80%, over a range of congestion limits (Fig. 6). It is observed that the LMPs are lowest when line limits are not imposed (no congestion). When the transmission capacity is 100% the LMP increases to about $3/MWh and remains in that range up to congestion limit of 40%, thereafter, for a congestion limit of 35%, it is significantly high.

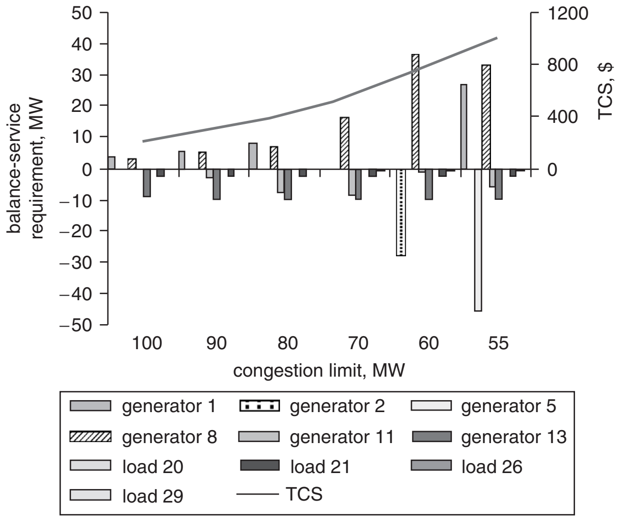

Fig. 5 *Bus-wise balance service procured by ISO for various congestion limits (LSF = 130%)*

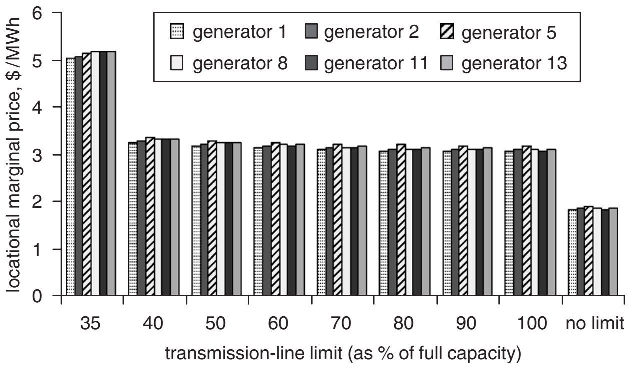

Fig. 6 *Variation of LMP for different transmission-capacity limits*

The above analysis was further extended to a range of LSF values. We observed that, as LSF is increased, the capability of the transmission system to withstand loading reduces. For example, with LSF = 80%, the system can operate even with a 35% congestion limit, but when LSF = 120%, it can only be operated at up to 85% congestion limit. Therefore, to maintain the 100% line flow for LSF = 120%, the ISO will be required to procure energy-balance services to alleviate transmission congestion. It can be stated that the lower the LSF, the more is the flexibility available to the ISO for congestion management.

Based on the above discussions, an important conclusion can be derived, as demonstrated in Fig. 7. The plot in Fig. 7

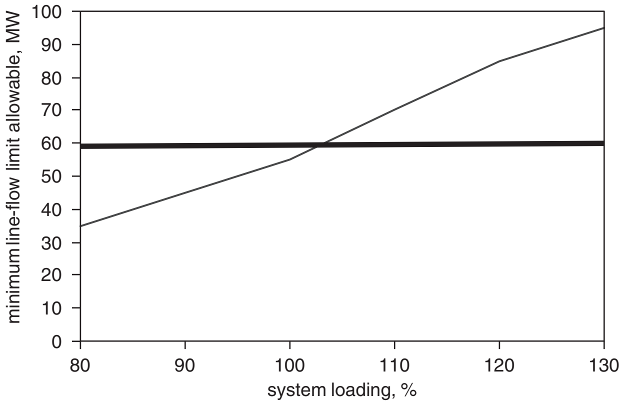

Fig. 7 *Relationship between the congestion limit and system loading*

shows the minimum line-flow limit on the transmission system that is allowable, as the system loading is varied over a range of LSF. For example, it can easily be determined from the plot that, if the allowable congestion limit is 60 MW (shown by the bold horizontal line), then the maximum allowable LSF is slightly more than 100%. By moving the bold horizontal line up and down and examining the LSF at which it intersects the graph, the maximum LSF points can easily be determined for various congestions limits set by the ISO.

3.3 Transmission congestion management under contingency conditions

Now we consider a set of contingencies in the transmission system for the same model described in Section 3.2 with the ISO's objective being to minimise TCS, but now considering that there is no transmission constraint. Table 1 provides the detailed results of bus-wise procurement of energy-balance services for five different contingency cases and the corresponding TCS.

From the simulations carried out, and from the results reported in Table 1, we observe that:

(i) In all the above contingency cases, generator 8 is always required to provide up-regulation services. Generators 5 and 11 are required, in some cases, to provide down-regulation services. Further, during simultaneous outage of two lines, down-regulation from loads is also required.

(ii) In case 5 the TCS is significantly higher than for the other cases. This is because of the high amount of balance service required by the ISO for congestion relief during multiple outages.

(iii) When certain transmission lines were on outage, e.g. line 14–15 or line 21–22 (not shown in Table 1), the transmission congestion is not significant and TCS remains at zero. This implies that the ISO does not have to invoke the energy balance service market in those cases.

(iv) In some other transmission line outages, e.g. line 2–4 or line 10–22 (not shown in Table 1), the energy balance service alone is not adequate to manage the transmission congestion. In such cases, the ISO will have to invoke other additional measures.

Table 1: Procurement of balance services by ISO during outages (no transmission limits)

Bus	PG^+, MW	PG^-, MW	PD^+, MW	PD^-, MW	TCS, $
Case 1: line 4–6 on outage					
8	8.03	–	–	–	21.12
11	–	8.10	–	–	
Case 2: line 10–21 on outage					
8	10.89	–	–	–	43.16
11	–	11.00	–	–	
Case 3: transformer 6–9 on outage					
5	–	8.15	–	–	18.99
8	8.23	–	–	–	
Case 4: lines 4–6 and 14–15 on simultaneous outage					
2	–	1.75	–	–	17.77
8	0.39	–	–	–	
20	–	–	–	0.22	
21	–	–	–	1.75	
Case 5: line 2–5 and transformer 6–9 on simultaneous outage					
5	–	17.45	–	–	1218.2
8	18.3	–	–	–	
11	–	0.02	–	–	

(v) The up- and down-regulation prices for the generators and customers are set at the highest accepted offers in each case.

Further, we now examine how the proposed model works during contingency conditions for various transmission-congestion limits. In Table 2, a detailed breakdown of bus-wise procurement of energy-balance services is provided for each of the congestion-limit cases considered.

Table 2: Procurement of balance services by ISO for various congestion limits (outage of transformer 6–9)

	Congestion limit imposed by ISO					
	100 MW	90 MW	80 MW	70 MW	60 MW	55 MW
Bus	5	5	5	5	5	5
BS	P_{G-}	P_{G+}	P_{G+}	P_{G+}	P_{G+}	P_{G+}
Amount	2.3	1.9	6.2	10.7	15.5	17.91
Bus	8	8	8	8	8	8
BS	P_{G+}	P_{G+}	P_{G+}	P_{G+}	P_{G+}	P_{G+}
Amount	20.9	23.5	25.7	27.6	29.3	30.0
Bus	11	11	11	11	11	11
BS	P_{G-}	P_{G-}	P_{G-}	P_{G-}	P_{G-}	P_{G-}
Amount	20.9	27.8	34.6	41.3	47.8	51.0
Bus	14	14	14	14	14	14
BS	P_{D+}	P_{D+}	P_{D+}	P_{D+}	P_{D+}	P_{D+}
Amount	0.6	0.6	0.6	0.6	0.6	0.6
Bus	20	20	20	20	20	20
BS	P_{D-}	P_{D-}	P_{D-}	P_{D-}	P_{D-}	P_{D-}
Amount	0.22	0.22	0.22	0.22	0.22	0.22
Bus	21	21	21	21	21	21
BS	P_{D-}	P_{D-}	P_{D-}	P_{D-}	P_{D-}	P_{D-}
Amount	1.75	1.75	1.75	1.75	1.75	1.75
TCS, $	162.82	207.24	257.5	307	355.65	379.69

From Table 2 we can draw the following conclusions:

(*a*) Generators 5, 8 and 11 are always selected to provide the energy-balance services for congestion management by the ISO. While generator 8 and 11 are invoked for up- and down-regulation, respectively, the generator at bus 5 is required for down-regulation when the congestion limit is 100 MW. However, when the congestion limit is continuously reduced, generator 5 is called on to provide up-regulation in increasing quantities. Also, the regulation required from generators 8 and 11 increases as the congestion limit is reduced.

(*b*) The ISO also procures a small amount of up-regulation from the customer at load bus 14 and down-regulation services from the loads at buses 20 and 21. However, note that the quantity procured from the customers is constant even when the congestion limit is changed over a range.

(*c*) TCS increases as the congestion limit reduces and the transmission system is congested.

3.4 Computational requirements of BSAM vis-à-vis OPF-based congestion management

It is important to demonstrate the computational advantages of the proposed BSAM-based congestion management scheme as against a classical OPF-based congestion management that includes the detailed transmission constraints. Simulations have now been carried out by excluding the GGDF-based congestion constraints (10) and (11) and replacing them with the following full-scale line constraints

$$\mathrm{Re}\{I_{i,j}\} = V_j Y_{i,j}\cos(\theta_{i,j}+\delta_j) - V_i Y_{i,j}\cos(\theta_{i,j}+\delta_i) + V_i Y_{i,j}^{ch}\sin(\delta_i) \tag{14}$$

$$P_{i,j} = V_i\lfloor\cos(\delta_i)\cdot\mathrm{Re}\{I_{i,j}\} + \sin(\delta_i)\cdot\mathrm{Im}\{I_{i,j}\}\rfloor \tag{15}$$

$$P_{i,j} \le P_{i,j}^{max} \tag{16}$$

Both the BSAM model and the traditional congestion-management model are programmed in the GAMS environment [17], using the well-known MINOS5 solver for solving nonlinear mixed-integer-programming problems. The computational performance of the two models is shown in Table 3.

Table 3: Comparison of computational performance of the proposed BSAM model with a classical OPF based congestion management model

	Congestion management using the proposed BSAM model	Congestion management using OPF with full transmission constraints
Number of variables	273	4878
Number of equations	175	3662
Model generation time, s	0.125	0.328
Model execution time, s	0.141	0.359
Iterations	214	1049
Workspace allocated, MB	0.41	2.78
Resource usage	0.207	2.242

It is clearly seen from Table 3 that the proposed BSAM model introduces significant computational efficiency in terms of model size, model generation and execution time, the number of iterations and the workspace required. When large practically sized power systems are handled, these advantages will be of immense significance for the real-time application of congestion management.

4 Concluding remarks

Transmission congestion management is a challenging issue in deregulated power systems and the system operator is faced with handling this task on a day-to-day basis. Many approaches have been proposed and applied to address this problem. In this paper, an attempt has been made to handle the congestion management problem through the framework of energy balance service markets, thereby providing the ISO the advantage of taking its decision on alleviating congestion very close to actual operation time. The proposed scheme works on similar lines of the energy-balance market in that the providers (generators and customers) offer their price and quantity bids. However, it is different in the way that the ISO arrives at the optimal procurement of the services—by taking into account the location aspects of the service providers through the calculation of generalised generation distribution factors. From the simulations carried out, it can be observed that the ISO is able to manage transmission congestion effectively for various load scaling factors and congestion limits, and also during contingency conditions. However, under some extreme contingency conditions the energy-balance service is not able to remove all congestion by itself, and additional measures will be required.

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6 Appendix: Calculation of GGDF

The generalised generation distribution factors (GGDFs) denoted by $D_{ij,k}$ [15, 16], relate the active power flow on a transmission line connecting buses i and j (P_{ij}) to the injected power at a generator bus k. The active power flow on the line between buses i and j can be expressed as

$$P_{ij} = \sum_{k=1}^{N} D_{ij,k} P_{inj,k} \tag{17}$$

In (17), $D_{ij,k}$ are the GGDFs which depend on the system operating conditions and can be calculated directly from the elements of the bus-reactance matrix and the load-flow solution executed after the real power market settlement, and using the generation-shift distribution factors $A_{ij,k}$, as follows:

$$D_{ij,k} = A_{ij,k} + D_{ij,R} \tag{18}$$

In (18), $D_{ij,k}$ are the GGDFs for line *i-j* because of the slack bus k, and can be obtained as

$$D_{ij,k} = \frac{P_{ij} - \sum_{R}^{N} A_{ij,k} P_{inj,k}}{\sum_{k=1}^{N} P_{inj,k}} \tag{19}$$

The generation-shift distribution factors $A_{ij,k}$ are defined as

$$A_{ij,k} = \frac{X_{ik} - X_{jk}}{X'_{ij}} \tag{20}$$

In (20), X_{ik} and X_{jk} are elements of the bus reactance matrix, and X'_{ij} is the reactance of line *i-j*.