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Linear Electricity Spot Market Constraints for Managing Post-Separation Frequency Deviations

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***Abstract*— Electric power systems occassionally experience transmission outages that split the system into electrically separate islands. Within each island there could be a significant mismatch between the mechanical energy associated with the rotation of generator turbines and the aggregate electrical demand and losses. This results in frequency deviations in each island that are managed by a number of different control actions, including governor response and load shedding. This paper develops a set of linear constraints that can be included in an electricity spot market formulation so that resources can be dispatched in a way that prevents the violation of post-separation frequency standards. The paper shows how to derive the constraints directly from a linear time invariant power system model. The derivation proceeds in a direct and unambiguous manner which is a desirable feature within a restructured electricity industry because often engineering judgement is subject to the scrutiny of other industry decision-makers including the commercial decision-makers of corporations and the centralized decision-makers of regulatory bodies. The technique for deriving the constraints can be used to implement an online decision-support tool for system and/or market operators to prevent post-contingency islands from violating frequency standards. The paper illustrates their use through a simple example.**

I. INTRODUCTION

Electric power systems occassionally experience contingencies that split the system into electrically separate islands. Within each island there could be a significant mismatch between the mechanical energy associated with the rotation of generator turbines and the aggregate electrical demand and losses. This results in frequency deviations that are managed through the action of several different forms of control including the response of governors, passive response of electrical demand to frequency deviations and active devices that trip demand (load shedding) depending on either the detected rate of change in frequency or if frequency deviations fall outside a particular band. The actions that follow load shedding in the island can sometimes be unpredictable and thus there is significant benefit in being able to guard the system (or specific parts of it) against frequency deviations that trigger such actions in the first place.

This paper shows that under some reasonable assumptions, it is possible to dispatch resources so that they satisfy post-separation frequency standards using an electricity spot market model. The standards are expressed in terms of bounds on the maximum post-separation frequency deviation, the rate of change in post-separation frequency and the steady-state frequency deviation. This is achieved by including a set of linear security constraints in a near real-time electricity spot market process (or an economic dispatch process) which are derived directly from a linear time invariant low-order frequency response model of the power system, similar to that presented in [1]. The constraints could be organized in a way that enables them to be relaxed if the cost associated with satisfying the post-separation frequency standards becomes too expensive.

This paper restricts attention to describing the technique that is used to construct the post-separation security constraints and to demonstrating that it can work within the context of an electricity spot market optimization. Issues associated with their inclusion in an electricity spot market such as pricing, incentives for market participants and cost-recovery are not explicitly discussed.

II. POST-SEPARATION POWER SYSTEM MODEL

A. Definitions and Objective

An important aspect of operating an electric power system is to minimize interruptions to service delivery, assuming it is economic to do so. One way to reduce the likelihood of service disruption within an island following a separation event is to ensure that the frequencies within each island satisfy certain properties similar to those that are described in frequency standards such as [7] or [8]. In some situations, the failure to satisfy such standards can result in widespread blackouts such as that recently reported in Europe on 4 November 2006, [12].

Generally these properties can be characterized in the following way:

- containment of frequency within $\pm F^{\max}$ of the nominal frequency; that is, $|f(t)| \leq F^{\max} \quad \forall t \geq 0$ where $f(t)$ represents the post-contingency frequency deviation (Hz) at time t following the contingency and $F^{\max}$ is the largest allowed frequency deviation (Hz);
- frequency to be within certain tolerances for specific time periods t_n $(n = 1, 2, \ldots)$ following the contingency; that is, $|f(t_n)| \leq F_n^{\text{tol}}$. If the time periods t_n are long enough for the system to have entered into a steady-state, then we call this the *steady-state frequency deviation* and

- express it as $|f(\infty)| \leq F_{ss}$ where $F_{ss}^{\max}$ is the steady-state frequency band (Hz); and
- maintaining the initial rate of change within some bounds, that is $|\dot{f}(0)| \leq \dot{F}^{\max}$.

These concepts are illustrated in Fig. 1.

The objective of this paper is to model the dynamic behavior of a power system following a separation event and use it to derive a set of static (and linear) security constraints that can be used in an electricity spot market to dispatch resources such that the frequency standards following a separation event are satisfied. The derivation of the security constraints occurs in a direct and unambiguous manner. This is a desirable feature within a restructured electricity industry because power system security is an issue that is typically addressed by engineers in an environment that is subject to the scrutiny of decentralized decision-makers such as market participants who have a stake in spot market outcomes, as well as centralized decision-makers such as regulatory bodies who have a stake in the market being operated transparently while also satisfying power system standards. The technique for deriving the constraints can be implemented as an online decision-support tool for system and/or market operators to assist in dispatching resources in a way that avoids the violation of frequency standards, in situations when the risk of separation is considered credible, for example [6].

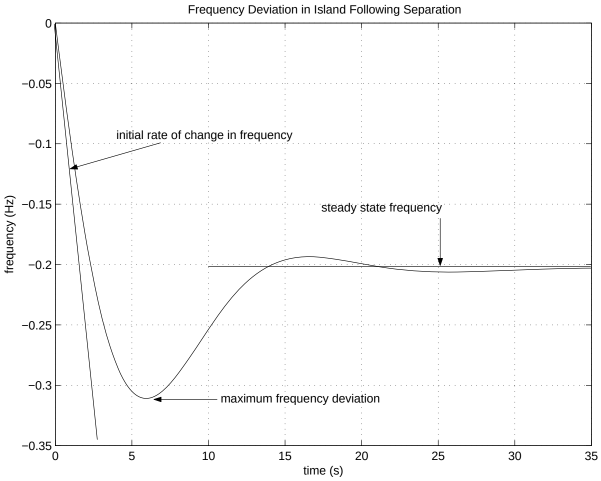

Fig. 1. Illustration of Definitions

B. Dynamic Power System Model

Following a separation event, the average power system frequency in each island exhibits behavior that can be approximated by a low-order power system model that accounts for generator governor action and the passive response of load to variations to frequency. The following model is linear and time-invariant and captures the main features that are important in the minutes following a major disturbance. It is based on the model described in [1], however similar models also appear in [2], [3], [4] and [5]. It is useful to note that any linear time-invariant system that is stable could be used in the analysis that follows.

$$\begin{bmatrix} \dot{f}_i(t) \\ \dot{p}_{i1}(t) \\ \vdots \\ \dot{p}_{iN}(t) \end{bmatrix} = \begin{bmatrix} \delta_i & \sigma_i & \cdots & \sigma_i \\ \gamma_{i1} & \tau_{i1} & \cdots & 0 \\ \vdots & \vdots & \ddots & \vdots \\ \gamma_{iN} & 0 & \cdots & \tau_{iN} \end{bmatrix} \begin{bmatrix} f_i(t) \\ p_{i1}(t) \\ \vdots \\ p_{iN}(t) \end{bmatrix} + \begin{bmatrix} -\sigma_i \\ 0 \\ \vdots \\ 0 \end{bmatrix} p(t), \quad i \in \mathcal{I} \tag{1}$$

where the index $i \in \mathcal{I}$ represents potential islands with $\mathcal{I}$ used to enumerate potential post-separation islands, $f_i(t)$ is the frequency deviation (Hz) in island i, $p_{ij}(t)$ is the mechanical power deviation (MW) away from an equilibrium characterized by the setpoint of generator $j \in \mathcal{G}_i$ in island i where $\mathcal{G}_i$ is the set of generators connected to island i where in order to simplify notation we have assumed that the generators within the island i are labelled $1, \ldots, N$, $p(t)$ is an exogenous electrical disturbance (MW) that represents the power flow on the outaged transmission line that gave rise to islanding, δ_i, σ_i, γ_{ij} and τ_{ij} are constants indexed over potential islands i and generators j, as follows:

$$\delta_i = -\frac{D_i}{2H_i}; \quad \sigma_i = \frac{f_0}{2H_i S_0}; \tag{2}$$

$$\gamma_{ij} = -\frac{S_0}{f_0 T_{ij} R_{ij}}; \quad \tau_{ij} = -\frac{1}{T_{ij}} \tag{3}$$

where the constants are related to physical properties of the generators connected to the island with definitions as follows, H_i is the sum of machine inertia constants (s) and any inertia attributable to other devices connected to the system, D_i is the damping coefficient which accounts for the passive response of load to frequency deviations, f_0 is a constant representing the nominal system frequency (Hz), S_0 is the MVA base of the system, T_{ij} is the dominant turbine time constant (s) for generator j in island i and R_{ij} is the governor droop of generator j in island i.

The model of equation (1) is referred to in this paper as a *low-order frequency response model* of the power system and can be compactly written as:

$$\dot{\mathbf{x}}_i(t) = A_i \mathbf{x}_i(t) + \mathbf{b}_i p(t) \tag{4}$$

$$y_{ik}(t) = \mathbf{e}_{ik}^T \mathbf{x}_i(t) \tag{5}$$

where $i \in \mathcal{I}$, $k \in \{1, \ldots, N+1\}$ is an index that is used to select which state is used as the system output (this is useful later), $\mathbf{x}_i(t) \in \mathbb{R}^{N+1}$, $A_i \in \mathbb{R}^{N+1 \times N+1}$ and $\mathbf{b}_i \in \mathbb{R}^{N+1}$ are defined in an obvious way from equation (1) and $\mathbf{e}_{ik} \in \mathbb{R}^{N+1}$ is a vector comprising all zeros except for element k. It is assumed that A_i is invertible.

III. DERIVATION OF LINEAR SECURITY CONSTRAINT SETS

A. Steady-State Frequency Deviation

In some instances, it is desirable to ensure that the steady state frequency deviation (and resulting deviations in mechanical power of the generators due to governor action) are held within limits. The steady state of the system represents the outcome in the absence of any other control actions (such as setpoints being adjusted by an automatic generation control scheme) or variations in the load. If we assume that $p(t) = \Delta p$ (a constant) then the steady state of equation (1) (breaking it into frequency deviations and mechanical power deviations) is given by:

$$\begin{aligned} f_i(\infty) &= y_{i1}(\infty) \\ &= -\mathbf{e}_1^T (A_i)^{-1}\mathbf{b}_i \Delta p \\ &\triangleq K_i \Delta p \end{aligned} \tag{6}$$

$$\begin{aligned} p_{ij}(\infty) &= y_{i,j+1}(\infty) \\ &= -\mathbf{e}_{j+1}^T (A_i)^{-1}\mathbf{b}_i \Delta p \\ &\triangleq K_{ij} \Delta p \end{aligned} \tag{7}$$

B. Initial Rate of Change in Frequency

If we compute $\dot{\mathbf{x}}_i(0)$ then, based on equation (4), we have the following:

$$\dot{\mathbf{x}}_i(0) = A_i \mathbf{x}_i(0) + \mathbf{b}_i \Delta p \tag{8}$$

Where $\mathbf{x}_i(0)$ is the initial condition of system. If we assume that at $t = 0$ the frequency deviation, $f_i(0) = 0$ and that the mechanical power for each generator, $p_{ij}(0) = 0$, then the initial frequency acceleration is given by the following:

$$\begin{aligned} \dot{f}_i(0) &= -\sigma_i \Delta p \\ &\triangleq L_i \Delta p \end{aligned} \tag{9}$$

While in this paper we assume that the initial conditions are zero, it is possible to construct constraints that take the initial conditions into account.

C. Maximum Frequency Deviation

The analytical solution to equation (4), with $p(t) = \Delta p$ is the following:

$$\begin{aligned} \mathbf{x}_i(t) &= \exp(A_i t)\mathbf{x}_i(0) + \int_0^t \exp\big(A_i(t-\tau)\big)\mathbf{b}_i d\tau.\Delta p \\ &= A_i^{-1}\big(\exp(A_i t) - I\big)\mathbf{b}_i \Delta p \end{aligned} \tag{10}$$

If A_i is stable, (an unstable A_i indicates that the system is unlikely to survive separation) then the maximum frequency deviation will be the first $t \geq 0$ such that the following equals zero:

$$\begin{aligned} \dot{f}_i(t) &= \mathbf{e}_1^T \dot{\mathbf{x}}_i(t) \\ &= \mathbf{e}_1^T \exp(A_i t)(A_i \mathbf{x}_i(0) + \mathbf{b}_i \Delta p) \\ &= \mathbf{e}_1^T \exp(A_i t)\mathbf{b}_i \Delta p \end{aligned} \tag{11}$$

and similarly the largest $p_{ij}(t)$ (mechanical power deviation) occurs when the following becomes zero (in fact, of interest is the first zero such that $t > 0$ since $p_{ij}(0) = 0$):

$$\begin{aligned} \dot{p}_{ij}(t) &= \mathbf{e}_{j+1}^T \dot{\mathbf{x}}_i(t) \\ &= \mathbf{e}_{j+1}^T \exp(A_i t)\mathbf{b}_i \Delta p \end{aligned} \tag{12}$$

Assume that $t = t^{max}$ is such that $f(t^{max}) = 0$ and $t = t_j$ is such that $p_{ij}(t_j) = 0$. Then we compute from the above equations:

$$\begin{aligned} f_i(t_{\text{max}}) &= \mathbf{e}_1^T A_i^{-1}\big(\exp(A_i t_{\text{max}}) - I\big)\mathbf{b}_i \Delta p \\ &= M_i \Delta p \end{aligned} \tag{13}$$

$$\begin{aligned} p_{ij}(t_j) &= \mathbf{e}_{j+1}^T A_i^{-1}\big(\exp(A_i t_j) - I\big)\mathbf{b}_i \Delta p \\ &\triangleq M_{ij} \Delta p \end{aligned} \tag{14}$$

It should be noted that it is necessary to find a way of solving equations (11) and (12). A simplistic heuristic approach is to firstly find t^{max} using a gradient search with initial condition $t = 0$. Having found t^{max}, this can be used as the initial condition in the gradient search for each t_j. This tends to work because the gradient search will naturally locate the next local minima in the vicinity of the initial point and t^{max} is usually close enough to t_j. It is recognized that superior techniques exist to solve this problem, however this is outside the scope of this paper.

IV. ELECTRICITY SPOT MARKET SECURITY CONSTRAINTS

A. Constraint Generation Concept

In restructured electricity industries that have near real-time spot markets, such as the Australian National Electricity Market, the system operator is usually allowed to invoke (or 'activate') constraints to guard the system against entering into an insecure state. We outline briefly the design of an online decision-support tool to assist the operator in satisfying post-separation frequency standards. The basic paradigm potentially applies to all forms of security criterion and need not be restricted to managing the post-separation security issue discussed in this paper.

The key processes and information flows are illustrated in Fig. 2. The **electricity spot market** process is a linear program similar to those described in [9], [10] and [11]. The purpose is to price and dispatch resources in a security-constrained manner subject to demand (and other) forecasts, offers and bids from market participants and other exogenous inputs including security constraints.

The **security constraint generation** process constructs the dynamic model of equation (1) for each potential island that has been identified using parameters for the units that are presently considered to be online and derive constraints of the form of equations (6), (7), (9), (13) and (14). It then activates those constraints in the electricity spot market until the time when system operator believes the threat of separation no longer exists whereupon the constraints would be revoked. The **database of system parameters** process includes the parameters necessary to construct the dynamic model and may well interface to online parameter estimation tools or systems used to hold technical data for dynamic power system simulations.

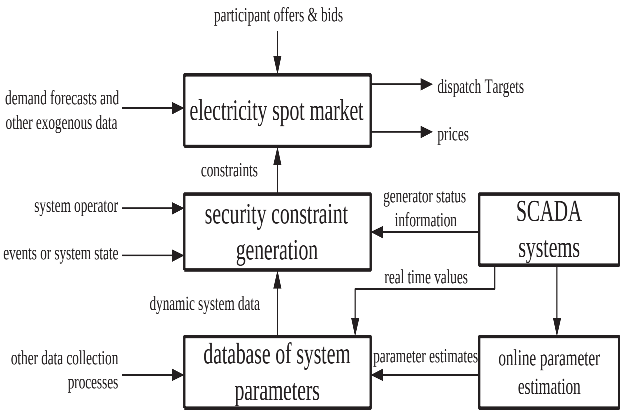

Fig. 2. Scheme for generation of constraints for use in electricity spot markets

B. Electricity Spot Market Formulation

This section presents a very simple linear programming formulation for an electricity spot market to illustrate how the system separation constraints would be incorporated.

Minimize:

$$J = \sum_{j \in \mathcal{G}} C_j g_j \tag{15}$$

which reflects the cost of supply in a very simplified way. Set $\mathcal{G}$ is a set of generators, C_j is the offered cost of supply for generator j (\$/MWh) and g_j is the generation decision-variable for generator j.

Subject to:

$$0 \le g_j \le G_j^{\max}, \qquad j \in \mathcal{G} \tag{16}$$

$$|p_k| \le P_k^{\max}, \qquad k \in \mathcal{L} \tag{17}$$

where $G_j^{\max}$ is the maximum amount of generation that can be supplied by generator j, p_k is the power flow decision-variable reflecting the power flow between the two zones that could become islands, $P_k^{\max}$ is the maximum possible power transfer on the line (related to the thermal MVA rating of the line), $\mathcal{L}$ is the set of lines between the part of the system that may become islanded (it's likely there will be just a single circuit - the failure of which results in separation). Equation (16) reflects generator limits and (17) reflects the maximum amount of power that can be transferred between the two zones that could become islands.

$$\sum_{j \in \mathcal{G}_i} g_j - N_i = \sum_{k \in \mathcal{F}_i} p_k - \sum_{k \in \mathcal{T}_i} p_k, \qquad i \in \mathcal{I} \tag{18}$$

where N_i is the aggregate net demand in separation zone i, $\mathcal{F}_i$ is the set of lines that transfer power from island $i \in \mathcal{I}$, $\mathcal{T}_i$ is the set of lines that transfer power to island $i \in \mathcal{I}$. Equation (18) is the overall power balance in each separation zones; this could be represented by a finer-grained model of the system, however to illustrate the concept we simply use power balances in potential separation zones.

The following equations represent steady-state frequency constraints:

$$|f_i(\infty)| \le F_{\text{ss}}^{\max}, \qquad i \in \mathcal{I} \tag{19}$$

$$f_i(\infty) = -K_i p_k, \quad i \in \mathcal{I}, \quad k \in \mathcal{T}_i \tag{20}$$

$$f_i(\infty) = K_i p_k, \quad i \in \mathcal{I}, \quad k \in \mathcal{F}_i \tag{21}$$

$$0 \le g_j - K_{ij} p_k \le G_j^{\max}, \quad i \in \mathcal{I}, \quad j \in \mathcal{S}_i, \quad k \in \mathcal{T}_i \tag{22}$$

$$0 \le g_j + K_{ij} p_k \le G_j^{\max}, \quad i \in \mathcal{I}, \quad j \in \mathcal{S}_i, \quad k \in \mathcal{F}_i \tag{23}$$

where most of symbols have already been defined except $\mathcal{S}_i$ which is the set of generators that are considered to be *online* at the present time; that is they are synchronized to the grid and are available to provide a governor response in the event of a separation event. Equation (19) is directly related to the frequency standards, equations (20) and (21) come from equation (6) and relate the steady state frequency to change in power flow that is experienced in each island following separation, equations (22) and (23) come from equation (7) and are included to ensure the steady-state deviation in power for each online generator remains within the generator's limits.

The next set of constraints allow for the containemnt of the rate of change in frequency:

$$|\dot{f}_i(0)| \le \dot{F}^{\max}, \quad i \in \mathcal{I} \tag{24}$$

$$\dot{f}_i(0) = -L_i p_k, \quad i \in \mathcal{I}, \quad k \in \mathcal{T}_i \tag{25}$$

$$\dot{f}_i(0) = L_i p_k, \quad i \in \mathcal{I}, \quad k \in \mathcal{F}_i \tag{26}$$

where equation (24) reflects the post-separation frequency standard and equations (25) and (26) reflect the relationship between power transfer and the resulting rate of change in frequency, as derived from equation (9).

Finally, the following constraints satisfy the maximum frequency deviation criterion:

$$|f_i(t^{\max})| \le F^{\max}, \qquad i \in \mathcal{I} \tag{27}$$

$$f_i(t^{\max}) = -M_i p_k, \quad i \in \mathcal{I}, \quad k \in \mathcal{T}_i \tag{28}$$

$$f_i(t^{\max}) = M_i p_k, \quad i \in \mathcal{I}, \quad k \in \mathcal{F}_i \tag{29}$$

$$0 \le g_j - M_{ij} p_k \le G_j^{\max}, \quad i \in \mathcal{I}, \quad j \in \mathcal{S}_i, \quad k \in \mathcal{T}_i \tag{30}$$

$$0 \le g_j + M_{ij} p_k \le G_j^{\max}, \quad i \in \mathcal{I}, \quad j \in \mathcal{S}_i, \quad k \in \mathcal{F}_i \tag{31}$$

where equation (27) reflects the post-separation frequency standard and equations (25) and (26) reflect the relationship between power transfer and the resulting rate of change in frequency, as derived from equations (13) and (14).

It should be noted that it is not necessary to incorporate all classes of constraint, for example the steady-state frequency constraint equations may not be regarded as important and could be excluded.

V. EXAMPLE

A. Simplistic Test System

We demonstrate the concept by considering the network shown in Fig. 3 and the following hypothetical scenario:

1) The double circuit transfer capacity between zones 1 and 2 is 200MW - all other transmission corridors in the system have sufficiently high capacity to be unconstrained at all times, the net demand N_i in each zone is as per table I and generator status and other data as per table II. The spot market outcome at the

time is as described in section V-B (pre-outage) - since the threat of separation is not considered credible there are no post-separation constraints included in the spot market optimization.

2) One of the circuits between the two zones fails, thus a contingency giving rise to separation is considered credible. The system operator uses the online constraint generation tool described in section IV-A to invoke a set of security constraints to limit the transfer capability (and dispatch of generation) so that in the event that separation occurs, frequency standards are satisfied. It is deemed that only the maximum deviation and steady state security criterion need to be satisfied. The outcomes are examined in section V-C for different frequency standards.

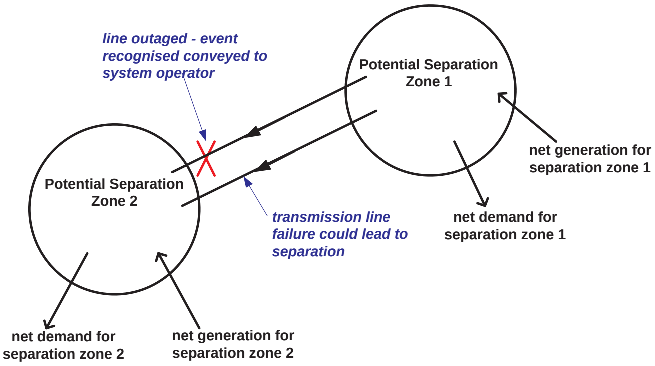

Fig. 3. Simple network showing a potential separation zone

TABLE I

SEPARATION ZONE DATA

Zone	D_i (damping)	H_i (s) (inertia)	N_i (MW)
1	25	250	550
1	65	450	680

TABLE II

GENERATOR DATA

Generator	Zone	C_j (\$/MWh)	G_j^{max} (MW)	T_j (s)	R_j	Status
G11	1	10.00	100	10.0	0.05	on
G12	1	11.00	80	2.0	0.06	on
G13	1	12.00	250	5.0	0.03	on
G14	1	13.00	230	1.0	0.02	off
G15	1	14.00	240	3.0	0.01	off
G16	1	15.00	225	2.5	0.10	off
G17	1	16.00	660	3.5	0.40	off
G18	1	17.00	160	11.0	0.50	off
G21	2	10.50	300	7.0	0.01	on
G22	2	14.50	120	13.0	0.02	on
G23	2	15.50	250	2.0	0.01	on
G24	2	16.50	100	5.0	0.05	off
G25	2	17.50	140	1.0	0.05	off
G26	2	18.50	500	8.0	0.08	off

B. Pre line outage

The electricity spot market prior to the occurrence of the line outage results in the dispatch pattern shown in table III and the shadow prices of the zonal balance equations are as shown in table IV (recall that the zones are used to represent a set of lossless nodal power balance equation - thus these prices are those that would occur at each network bus). The double-circuit line transfers power at its upper limit of 200MW from zone 1 to zone 2 (since zone 1 has a large amount of cheap generation).

TABLE III

PRE LINE OUTAGE GENERATOR DISPATCH (GENERATORS WITH ZERO TARGETS EXCLUDED)

Generator	g_j (MW) dispatch
G11	100.00
G12	80.00
G13	250.00
G14	230.00
G15	90.00
G21	300.00
G22	120.00
G23	60.00

TABLE IV

PRE LINE OUTAGE SEPARATION ZONE DATA

Zone	Zone price (\$/MWh)	Zone export/import (MW)
1	14.00	200.00
2	15.50	-200.00

C. Post line outage

The constraint generation process takes the data from tables I and II and computes K_i, K_{ij}, M_i, M_{ij} using the procedure described in sections III-A and III-C. The results are shown in table V. Note that only the generators that are considered online are included in the calculations. For the situation where we set the largest frequency deviation to be $F^{\text{max}} = 0.3$Hz and the steady-state frequency $F_{\text{ss}}^{\text{max}} = 0.2$Hz we obtain the results outlined in tables VI and VII. Figures 4 and 5 demonstrate the outcomes in each island should separation actually occur - showing that the standards and generator limits are adhered to.

TABLE V

VALUES FOR K_i, K_{ij}, M_i AND M_{ij} FOR ONLINE GENERATORS

Zone (i)	Generator (j)	K_i or K_{ij}	M_i or M_{ij}	t^{max} or t_j
1	-	-0.0020	-0.0028	5.6562
1	G11	0.0816	0.0816	108.8823
1	G12	0.0680	0.0855	8.1714
1	G13	0.1361	0.1422	11.9240
1	G14	0.2041	0.2717	6.8625
1	G15	0.4082	0.4802	9.3872
2	-	-0.0048	-0.0049	32.1962
2	G21	0.1519	0.1532	48.0757
2	G22	0.0759	0.0759	135.6962
2	G23	0.1519	0.1548	34.6952

TABLE VI

PRE LINE OUTAGE GENERATOR DISPATCH (GENERATORS WITH ZERO TARGETS EXCLUDED)

Generator	g_j (MW) dispatch
G11	96.60
G12	76.44
G13	244.08
G14	174.55
G21	300.00
G22	120.00
G23	218.33

TABLE VII

PRE LINE OUTAGE SEPARATION ZONE DATA

Zone	Zone price ($/MWh)	Zone export/import (MW)
1	13.00	41.67
2	15.50	-41.67

VI. CONCLUSION

This paper has examined the concept of deriving static linear constraints directly from a dynamic power system model as required by the system operator for inclusion in an electricity spot market. The constraints ensure resources will be dispatched such that post-separation frequency standards are satisfied. The concept is illustrated through a simple example that constrains the flow on a transmission line so that, in the event that separation occurs, each island will not violate security standards and the deviation of each generator within each island due to governor action will remain within its limits. The advantage of the technique is that it enables frequency deviations to be expressed naturally within a linear programming optimization framework and could be included in a way that could be implemented in the rare situations where the threat of separation is credible and detected by system operators. A further advantage is that the constraints are derived directly from a technical model of the power system, thus avoiding potentially controversial approximations in constructing electricity spot market constraints that potentially have commercial implications using a technically-oriented power system model.

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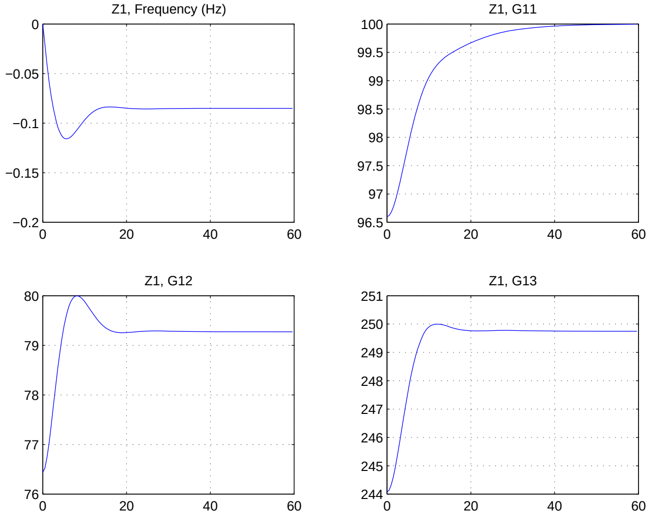

Fig. 4. Post-separation response in Zone 1

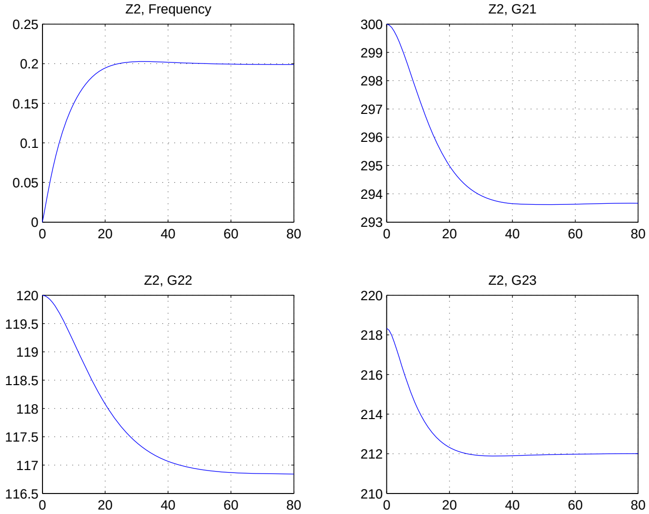

Fig. 5. Post-separation response in Zone 2

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