STABILITY ANALYSIS OF INTERCONNECTED POWER SYSTEMS COUPLED WITH MARKET DYNAMICS

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Abstract: The use of market mechanisms to determine generation dispatch, and the natural tendency to seek improved economic efficiency through rapid market updates, raises a critical issue. As the frequency of market based dispatch updates increases, there will inevitably be interaction between the dynamics of markets determining the generator dispatch commands, and the physical response of generators and network interconnections. This paper examines questions of stability in such coupled systems through numeric tests using various market update models, with detailed generator/turbine/governor dynamics, in the New England 39 bus test system. The results presented highlight the nature of potential instabilities and show the participation of physical and market quantities through eigen-analysis. Understanding of potential modes of instability in such coupled systems is of crucial importance both in designing suitable rules for power markets, and for designing physical generator controls that are complementary to market-based dispatch.

Keywords: market dynamics, power system dynamics, dynamic coupling, eigenvalues

1 Introduction

The potential benefits of near real time competitive markets to determine power production in the electric power industry has long been discussed. A key element for realizing potential benefits from markets is the presence of a robust transmission grid that allows wide spread access of power consumers to a range of (often geographically disperse) generators controlled by competitive producers. In general, as networks around the world have become better connected, the number of potential options available has increased, and the pressure for greater reliance on market mechanism has grown stronger [7]. However, these same conditions (large numbers of widespread generation sources coupled to a long distance transmission network) create a physical system in which the potential for undesirable dynamic response, and even electromechanical instability, is very real.

When designing power exchanges and policies for Independent System Operators (ISO) to manage competitive provision of electric power, it is necessary to consider whether the market operation itself leads to stable equilibrium conditions. At the same time, the physical power system must exhibit acceptable electromechanical response (with stability as a minimum criterion). It should be clear that if market mechanisms are being used to determine generator dispatch (with near real-time updates of the dispatch commands) there will exist dynamic coupling between the market update process and the physical response of the generator/network dynamics.

Therefore, under the assumption of market-based dispatch, considering of the stability of the coupled system incorporating both market operation and electromechanical power system dynamics simultaneously is necessary. There has been relatively little prior work in this topic within power systems literature. As rules for market-based dispatch vary throughout the US and around the world, any analytic treatment must make certain assumptions of how physical system conditions and market response interact. Alvarado [2, 3] considered the effect of coupling in one direction, with energy imbalance in the physical system, with or without network congestion, driving the market response. The work by Mota and Alvarado [4] gives the basic modeling for full, two-way dynamic coupling between market dynamics and power system electromechanical response. A discrete time frequency domain formulation is discussed in [12].

This paper refines the modeling in [4]. Before further discussion, it is useful to state several of the underlying assumptions [2, 3]:

- Marginal production costs are affine linear functions of generated power.
- Marginal benefit functions are negatively sloping affine linear functions of power consumption.
- A generator's power output command is a function of its marginal cost and the market price for power. Demand is also a function of marginal benefit and power price.
- Response of power suppliers and consumers to observed price is represented by continuous dynamics (as opposed to a discrete-time model of periodic price updates). The producer/consumer response characteristics are represented by first order linear differential equations.
- Network-wide power production is not precisely balanced to power consumption at all times; therefore instantaneous energy imbalance and frequency variation result. Energy imbalance leads to the need to control such imbalance to prevent system damage or unwanted relay action.

Section 2 describes the behavior of power producers and consumers in a market driven environment. Section 3 presents the ideal energy imbalance driven market-only dynamic model. Section 4 outlines the power system dynamic models. Section 5 proposes the improved frequency error market-only dynamic model. When the interconnected power system is coupled with market dynamics, the combined system can exhibit the dynamic behavior which is different from that of each subsystem. This is discussed in sections 6 and 7. In order to check the effect of the interaction between the two subsystems, numerical eigenanalysis is used to characterize possible interactions, using the example of the New England 39 bus test system [14]. Variation in key parameters is examined to determine ranges of values that yield stable operation.

The numerical studies suggest that to create a successful power market structure, market designers and regulators cannot ignore the dynamic interaction between the market and the physical, electromechanical dynamics of the power system.

2 Producer/Consumer Behavior

Neglecting network losses, the producer and consumer behavior for m power producers and n power consumers in a market driven environment can be approximated by the following simple first order differential equations

$$\tau_{gi}\dot{P}_{gi} = -b_{gi} - c_{gi}P_{gi} + \lambda, \quad i = 1 \ldots m \tag{1}$$

$$\tau_{dj}\dot{P}_{dj} = b_{dj} + c_{dj}P_{dj} - \lambda, \quad j = 1 \ldots n \tag{2}$$

where

P_{gi}	Power supply of producer i;
P_{dj}	Power demand of consumer j;
$b_{gi} + c_{gi}P_{gi}$	Marginal cost of supplier i;
$b_{dj} + c_{dj}P_{dj}$	Marginal benefit of consumer j;
λ	Price of power.

The above equations describe the following qualitative behavior: a generator increases its production when price exceeds its marginal production cost. Loads act to increase consumption when marginal benefit exceeds price. Each maximizes its profit or benefit by matching its marginal cost/benefit to market price at equilibrium. First order differential equations allow approximate representation of generator ramp rates and lags in response to power price changes.

The units of measure and assumed range for power price λ, power supply P_g and and power demand P_d, power producer cost parameters c_g and b_g, power consumer benefit parameters c_d and b_d, the ramp rate of P_g and P_d are listed in Table 1. The parameters of c_g, c_d, b_g, b_d are given in the appendix, chosen to match the above equilibrium equations and the power flow results for the New England 39 bus system based on a power price \$40/MWhr. Once the right hand side parameters in the above equations are determined, one may choose producer and consumer response constants τ_g and τ_d by assuming the ramp rate for generators and consumers lies in the range of $1 \sim 20$ MW/min. The specific power producer/consumer parameters are given in the appendix.

3 Energy Imbalance Market Dynamics

In a synchronous power system, energy imbalance is rarely sustained indefinitely. It must be reduced or driven to zero. In the traditional utility environment in the US, this objective is attained by automatic generation control (AGC) [11]. In a full, real-time market-driven model, it is reasonable to assume that market mechanisms might fulfill this role. In particular, one may hypothesize that price for power reflects the degree of energy imbalance. That is, an excess of power supplied to the grid depresses the value of the power, and vice versa. This concept was the basis for the proposals by Caramanis et al. [8] and has been recently promoted further by [9, 10]. Variations in the value of power depending real time energy balance is referred as frequency regulation pricing or ACE (Area Control Error) pricing. Under this model, and neglecting network loss effects, we propose the following equations to represent the ideal market-only dynamics for m power suppliers and n power consumers:

$$\dot{E} = \sum_{i=1}^{m} P_{gi} - \sum_{j=1}^{n} P_{dj} \tag{3}$$

$$\tau_\lambda \dot{\lambda} = -k_E E - \lambda \tag{4}$$

where

E	System energy imbalance;
τ_λ	Power price response rate constant;
k_E	Market stabilizer gain for energy imbalance.

The determination of the parameters τ_λ and k_E reflects the design mechanism of the power market. The result of an excess of energy is assumed to be a reduction of power price derivative , which changes according to the ratio $\frac{k_E}{\tau_\lambda}$. This ratio dictates the sensitivity of price to system energy imbalance E. Although power price feedback in (4)tends to stabilize the market, it is optional, and its presence depends on the market design. Without price feedback, the change of price is dependent only on energy imbalance, and steady state energy imbalance is driven to zero. With price feedback, the change of price depends not only on energy imbalance, but also on the current price, and there remains a steady state error in energy imbalance.

4 Power System Dynamics

The synchronous machines, exciters and voltage regulators, turbines and governors, are represented by well-established, textbook models used for electromechanical stability studies [5, 6].

4.1 Synchronous Machine Model

Synchronous machines are modeled by the 3^{rd} order flux decay model or 4^{th} order two axis model depending on the specification for each synchronous machine. Only the 4^{th} order two axis synchronous model is presented here, readers are referred to [5, 6] for 3^{rd} order and other synchronous models.

State Equations

$$T'_{q0}\dot{E}'_d = (x_q - x'_q)I_q - E'_d \tag{5}$$

$$T'_{d0}\dot{E}'_q = E_{fd} - (x_d - x'_d)I_d - E'_q \tag{6}$$

$$\dot{\delta} = \omega_s \omega \tag{7}$$

$$2H\dot{\omega} = P_m - \left[E'_q I_q + E'_d I_d - (x'_d - x'_q)I_d I_q\right] - D\omega \tag{8}$$

where δ is rotor angle from the synchronous reference. The quantity ω is per unit rotor speed deviation relative to the synchronous reference.

Table 1: Typical Range for power market parameters (power in p.u. with 100 MW base)

	λ	c_g	c_d	b_g, b_d	$dP_g/dt, dP_d/dt$
Units	\$/MWh	\$/MWhr	\$/MWhr	\$/MWhr	p.u./min (100 MW base)
Typical Range	20 $\sim$ 80	0.004 $\sim$ 0.012	-0.013 $\sim$ -0.003	20 $\sim$ 60	1/100 $\sim$ 20/100

Stator Algebraic Equations

$$0 = E'_d - V_d - r_a I_d + x'_q I_q \quad (9)$$

$$0 = E'_q - V_q - x'_d I_d - r_a I_q \quad (10)$$

where

$$V_d = \mathrm{Re}(\vec{V}_g e^{j(\frac{\pi}{2}-\delta)}) = V_g \sin(\delta - \theta) \quad (11)$$

$$V_q = \mathrm{Im}(\vec{V}_g e^{j(\frac{\pi}{2}-\delta)}) = V_g \cos(\delta - \theta) \quad (12)$$

$\vec{V}_g$ is the generator terminal voltage phasor, V_g is the amplitude of $\vec{V}_g$, θ is the phase angle of $\vec{V}_g$.

4.2 Exciter and Automatic Voltage Regulator (AVR) Model

Only IEEE type 1 exciter and AVR model is considered. The block diagram of this model is shown in Figure 1. The PSS is assumed to be inactive. The exciter saturation function is $S_e(E_{fd}) = 0.0039e^{1.555E_{fd}}$ [6].

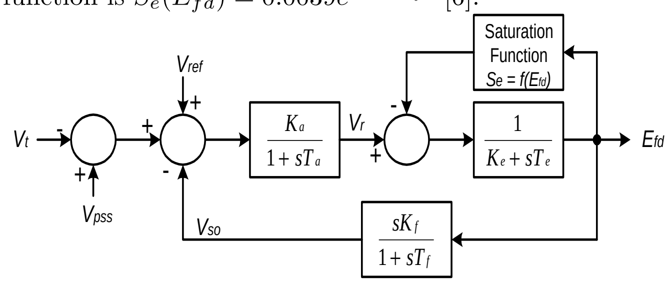

Figure 1: *IEEE TYPE 1 Exciter System*

$$T_e \dot{E}_{fd} = -[K_e + S_e(E_{fd})]E_{fd} + V_r \quad (13)$$

$$T_a \dot{V}_r = -V_r - K_a V_{so} + K_a(V_{ref} - V_t) \quad (14)$$

$$T_f \dot{V}_{so} = -V_{so} - K_f \frac{K_e + S_e(E_{fd})}{T_e} E_{fd} + K_f \frac{V_r}{T_e} \quad (15)$$

4.3 Turbine and Speed Governor Model

The block diagram of the turbine and speed governor model is shown in Figure 2.

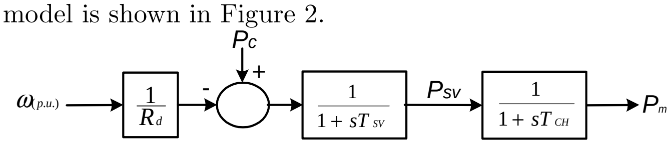

Figure 2: *Simplified Speed-Governor System*

$$T_{CH} \dot{P}_m = -P_m + P_{SV} \quad (16)$$

$$T_{SV} \dot{P}_{SV} = -P_{SV} + P_c - \frac{\omega}{R_d} \quad (17)$$

In Figure 2 ω is the per unit rotor speed deviation relative to synchronous speed, P_c is the power command, and P_m is the generator mechanical power.

If the market dynamics are considered, the power command P_c becomes the input point for coupling; it is set equal to the output P_g from the market dynamics model.

4.4 Power Flow and Load Representation

At generator buses the power balance equations are:

$$\vec{S}_{ti} - P_{Li} - jQ_{Li} - \vec{S}_{gi}(\theta, V) = 0 \quad (18)$$

where $\vec{S}_{ti}$ is the generator terminal complex power at generator bus i and $\vec{S}_{ti} = \vec{V}_{gi} I^*_{gi}$. $P_{Li} + jQ_{Li}$ is the terminal real power load at generator bus i. $\vec{S}_{gi}$ is the complex power injection at generator bus i, which is the function of bus voltages. V is the bus voltage magnitude vector. I^*_{gi} is the conjugate of the generator current at generator bus i. The above equation can be rewritten as:

$$V_i e^{j\theta_i}(I_{di} - jI_{qi})e^{-j(\delta_i - \frac{\pi}{2})} - P_{Li} - jQ_{Li} - \vec{S}_{gi}(\theta, V) = 0 \quad (19)$$

At load buses the power balance equations are:

$$P_{Lj} + jQ_{Lj} + \vec{S}_{Lj}(\theta, V) = 0 \quad (20)$$

where $P_{Lj} + jQ_{Lj}$, is the power consumption at load bus j. $\vec{S}_{Lj}$ is the complex power injection at load bus j. In power flow computation, loads are modeled as constant power. In power system dynamic analysis, loads are modeled as constant admittances. When the market dynamics are considered, the loads at non-consumer buses (e.g., loads in power plants) are represented as constant admittances and thus absorbed by the bus admittance matrix. At a power consumer bus j, the real power balance equation is modified as:

$$P_{dj} + Re(\vec{S}_{Lj}(\theta, V)) = 0 \quad (21)$$

5 Relation of Frequency Error to Energy Imbalance

The preceding sections present the ideal market-only dynamic model in terms of the system energy imbalance E. But in real power systems such abstract energy imbalance is impossible to measure. When the coupling between power system dynamics and market dynamics is considered, a way must be found to measure such energy imbalance. By analyzing the generator rotor acceleration equation (8) and ignoring network losses, the power demand is approximated by the sum of the square bracketed terms in (8). Since the damping term usually is small, the sum of right hand side of (8) closely approximates system power imbalance, and thus integrates to energy imbalance. So the weighted sum of frequency errors $\omega_{av} = \sum_i^m 2H_i\omega_i$ is a good approximation to system energy imbalance. The frequency error market-only dynamic model is described by the following first order differential equations

$$\tau_{gi} \dot{P}_{gi} = -b_{gi} - c_{gi} P_{gi} + \lambda, \quad i = 1 \ldots m \quad (22)$$

$$\tau_{dj} \dot{P}_{dj} = b_{dj} + c_{dj} P_{dj} - \lambda, \quad j = 1 \ldots n \quad (23)$$

$$\tau_\lambda \dot{\lambda} = -k_E \omega_{av} - \lambda \quad (24)$$

where $\omega_{av} = \sum_i^m 2H_i\omega_i$ is the average frequency deviation.

For the coupled market/power system, P_g is set to equal to the governor input P_c. The coupled market/power dynamic model can be best understood from the diagram of Figure 3.

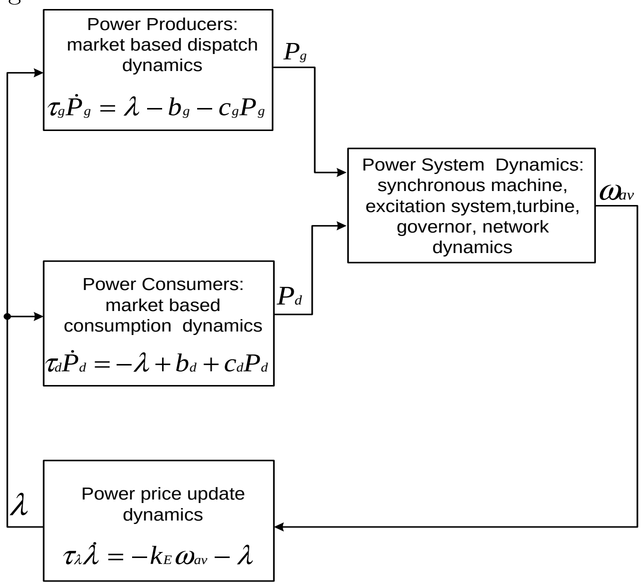

Figure 3*: Coupled market/power system dynamic model*

6 Market/Power System Linearized Model

The combined market/power system yields a set of differential/algebraic equations. The linearized version of the combined market and power system differential and algebraic equations has a structure that may be summarized in matrix form:

$$\left[\begin{array}{c} \Delta\dot{\underline{P}}_g \\ \Delta\dot{\underline{P}}_d \\ \Delta\dot{\lambda} \\ \hline \Delta\dot{\underline{X}}_{\text{gen}} \\ \hline \underline{0} \\ \underline{0} \\ \underline{0} \\ \underline{0} \\ \underline{0} \\ \underline{0} \end{array}\right] = \left[\begin{array}{c|c|c} \mathbf{J}_{mm} & \mathbf{J}_{mg} & \mathbf{J}_{ma} \\ \hline \mathbf{J}_{gm} & \mathbf{J}_{gg} & \mathbf{J}_{ga} \\ \hline \mathbf{J}_{am} & \mathbf{J}_{ag} & \mathbf{J}_{aa} \end{array}\right] \left[\begin{array}{c} \Delta\underline{P}_g \\ \Delta\underline{P}_d \\ \Delta\lambda \\ \hline \Delta\underline{X}_{\text{gen}} \\ \hline \Delta\underline{I}_d \\ \Delta\underline{I}_q \\ \Delta\underline{\theta}_g \\ \Delta\underline{\theta}_l \\ \Delta\underline{V}_g \\ \Delta\underline{V}_l \end{array}\right] \quad (25)$$

where

- $\mathbf{J}_{mm}$ Jacobian of power market state equations w.r.t. power market state variables;
- $\mathbf{J}_{gm}$ Jacobian of generator state equations w.r.t. power market state variables;
- $\mathbf{J}_{am}$ Jacobian of power system algebraic equations w.r.t. power market state variables;
- $\mathbf{J}_{gg}$ Jacobian of generator state equations w.r.t. generator state variables;
- $\mathbf{J}_{ga}$ Jacobian of generator state equations w.r.t. power system algebraic variables;
- $\mathbf{J}_{ag}$ Jacobian of power system algebraic equations w.r.t. generator state variables;
- $\mathbf{J}_{aa}$ Jacobian of power system algebraic equations w.r.t. power system algebraic variables.

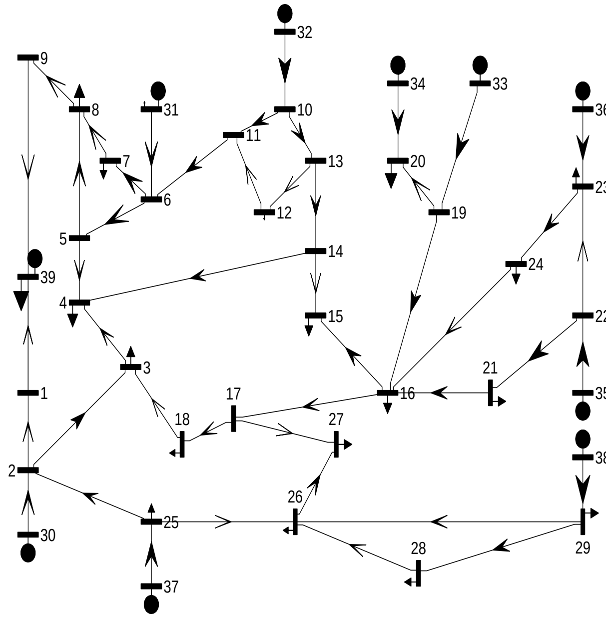

Figure 4*: One-line diagram of the New England System*

Grouping blocks, it is convenient to define:

$$\mathbf{J}_1 = \begin{bmatrix} \mathbf{J}_{mm} & \mathbf{J}_{mg} \\ \mathbf{J}_{gm} & \mathbf{J}_{gg} \end{bmatrix}, \ \mathbf{J}_2 = \begin{bmatrix} \mathbf{J}_{ma} \\ \mathbf{J}_{ga} \end{bmatrix} \quad (26)$$

$$\mathbf{J}_3 = \begin{bmatrix} \mathbf{J}_{am} & \mathbf{J}_{ag} \end{bmatrix}, \ \mathbf{J}_4 = \mathbf{J}_{aa} \quad (27)$$

So the above equations can be rewritten as:

$$\left[\begin{array}{c} \Delta\dot{\underline{P}}_g \\ \Delta\dot{\underline{P}}_d \\ \Delta\dot{\lambda} \\ \Delta\dot{\underline{X}}_{\text{gen}} \\ \hline \underline{0} \\ \underline{0} \\ \underline{0} \\ \underline{0} \\ \underline{0} \\ \underline{0} \end{array}\right] = \left[\begin{array}{c|c} \mathbf{J}_1 & \mathbf{J}_2 \\ \hline \mathbf{J}_3 & \mathbf{J}_4 \end{array}\right] \left[\begin{array}{c} \Delta\underline{P}_g \\ \Delta\underline{P}_d \\ \Delta\lambda \\ \Delta\underline{X}_{\text{gen}} \\ \hline \Delta\underline{I}_d \\ \Delta\underline{I}_q \\ \Delta\underline{\theta}_g \\ \Delta\underline{\theta}_l \\ \Delta\underline{V}_g \\ \Delta\underline{V}_l \end{array}\right] \quad (28)$$

Using the Schur complement formula[1], the eigenvalues of the coupled dynamic system can be computed from the matrix $\mathbf{J}_{\text{sys}} = \mathbf{J}_1 - \mathbf{J}_2\mathbf{J}_4^{-1}\mathbf{J}_3$.

7 New England 39 Bus System Example

The effect of the interaction between the market and the power system is illustrated using the classical New England 39 bus system. The system one-line diagram is shown in Figure 4. All the synchronous machines are modeled as two axis 4^{th} model except bus 1 which is treated as a 3^{rd} order flux decay model. The model of exciters and voltage regulators of all the generators is IEEE type 1. The turbines and speed governors for all the generators are modeled as the aforementioned 2^{nd} order model. The original system data can be found in [1, 14].

[1] An augmented solution is also possible [13].

7.1 Stability of the Power System

Using the modeling discussed in the preceding sections, the computation of eigenvalues for system dynamics is straightforward. The eigenvalue plot for this stable power system is shown in Figure 5. There is a 0 eigenvalue. It comes from keeping all generator rotor angles $\underline{\delta}$ as state variables. If synchronous machines damping is ignored, a second zero eigenvalue appears [6].

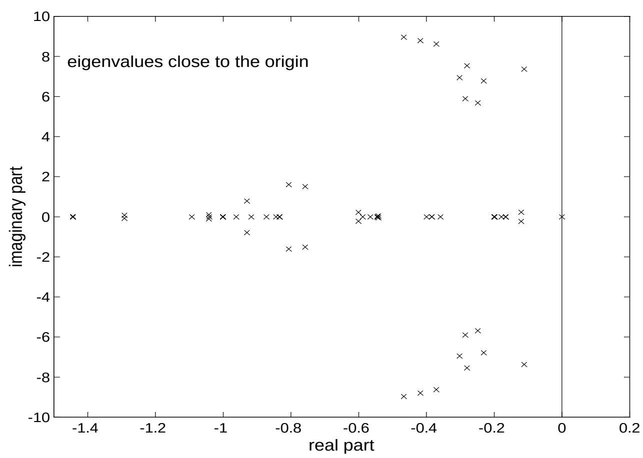

Figure 5: *Eigenvalue plot of stable New England system*

7.2 Stability of Ideal Market-only Dynamics

This section analyzes the stability of the ideal market-only dynamic model presented in sections 2 and 3. If the market dynamics are not coupled with the electric power system, the computation of the eigenvalues associated with the continuous market dynamics model is trivial. The market parameters are given in the appendix.

Assume the market parameters associated with power producers and consumers are fixed. The stability region for the ideal market-only dynamics with respect to market parameters k_E and τ_λ is the shaded area in Figure 6.

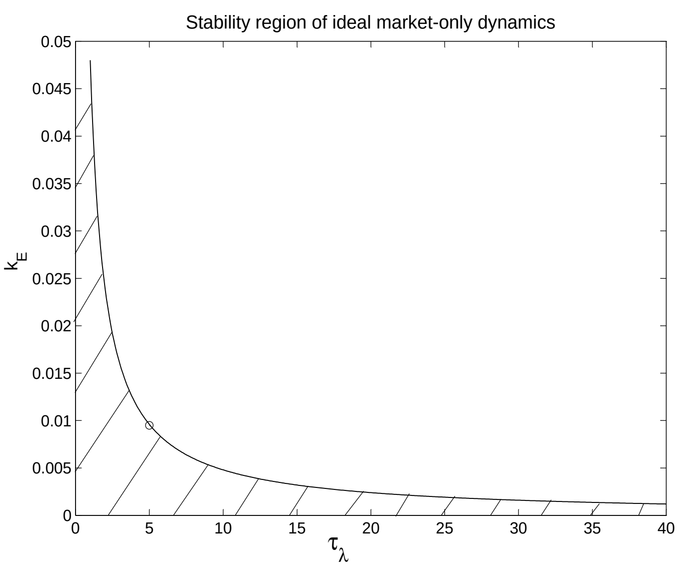

Figure 6: *Stability region of the ideal market-only dynamics w.r.t. k_E and τ_λ for New England system*

For a specific pair of τ_λ, k_E, (5, 0.0095) (this point shown in Figure 6), there is a pair of critically stable modes $-0.0006 \pm 0.0616i$. The computation of the corresponding normalized participation factors shows that these two modes are mainly associated with system energy imbalance E and power price λ with the corresponding normalized participation factors 1.00 and 0.30 respectively.

7.3 Stability of Interconnected System coupled with Frequency Error Market Dynamics

Consider next the stability of the coupled system. In order to examine the mechanism of power market design, the frequency error market dynamic model, described in section 5, is used here. Using the formulation derived in section 6, the eigenvalues of the coupled system can be easily calculated. The stability region with respect to the market parameters k_E and τ_λ is shown as the shaded area in Figure 7.

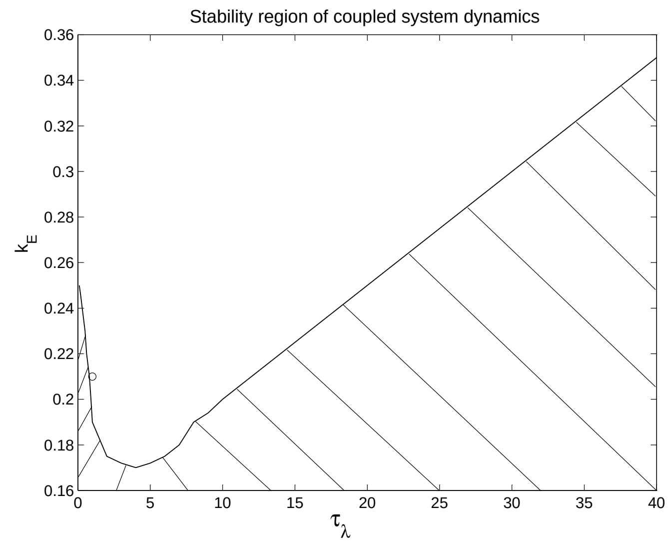

Figure 7: *Stability region of the coupled system dynamics w.r.t. k_E and τ_λ for New England system*

For the pair of τ_λ, k_E, (1, 0.21) (see Figure 7), there is only one pair of critically stable modes $0.0019 \pm 0.2533i$. The normalized participation factors associated with power supply P_g of power producers, power price λ, machine rotor angles δ, the machine rotor speed deviation ω, and the turbine mechanical power output P_m are shown in Table 2. For this specific pair of unstable modes, the states of the swing dynamics of the last machine have more participation due to its relatively large inertia and large contribution to system energy imbalance.

Putting the above two plots together on scaled coordinate axes leads to a plot of stability regions for both ideal market-only dynamics and coupled system dynamics. This plot is shown in Figure 8.

There are four regions (shaded areas) in this plot. Region (1) and (3) are the stability regions for ideal market-only dynamics. Region (1) and (2) are the stability regions for coupled system dynamics. In region (1) both of the market-only system and coupled system are stable. In region (2) the market-only system is unstable, yet the coupled system is stable. In region (3) the market-only system is stable, but the coupled system is unstable. In region (4), both of the systems are unstable. From Figure 8 it is clear that for the different combination of market

Table 2: Selected normalized participation factors associated with the unstable modes ($0.0019 \pm 0.2533i$) for the coupled system ($\tau_\lambda = 1$, k_E=0.21, the participation factor associated with price λ is 0.74)

Bus #	30	31	32	33	34	35	36	37	38	39
P_g	0.20	0.20	0.28	0.20	0.27	0.19	0.23	0.20	0.22	0.21
δ	0.089	0.044	0.068	0.058	0.082	0.0045	0.011	0.073	0.14	0.45
ω	0.42	0.29	0.35	0.27	0.25	0.31	0.25	0.23	0.32	1.00
P_m	0.22	0.20	0.26	0.20	0.26	0.19	0.24	0.20	0.23	0.22

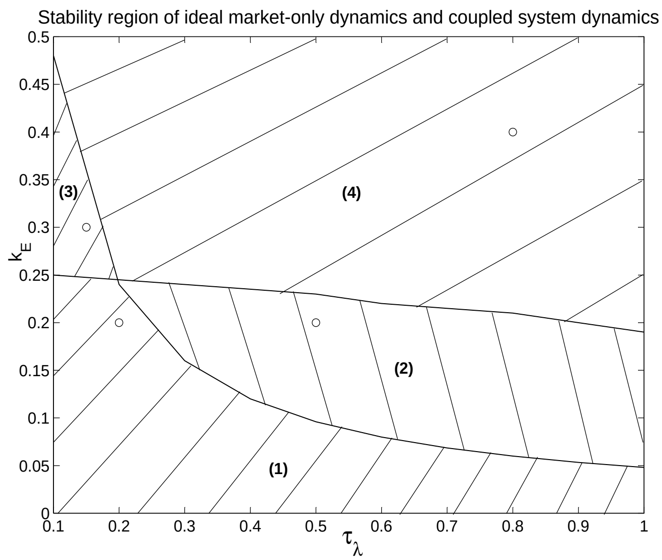

Figure 8*: Stability regions of the ideal market-only and coupled system dynamics w.r.t.* k_E *and* τ_λ *for New England system*

parameters (τ_λ, k_E), one may have very different stability results. Hence when designing power market policies, both of market system and electric power system must be considered to ensure reliable and secure operation.

To examine the nature of potential instabilities, consider one sample point, (τ_λ, k_E) pair, in each region. These four points are shown in Figure 8.

- For (0.2, 0.2) in region (1), both of the ideal market-only system and the coupled system are stable.
- For (0.5, 0.2) in region (2), the coupled system is stable, but the ideal market-only system is unstable with one pair of unstable modes $0.0112 \pm 0.2961i$, mainly associated with system energy imbalance and power price with the corresponding normalized participation factors 1.00 and 0.15.
- For (0.15, 0.3) in region (3), the ideal market-only dynamics are stable, yet the coupled system is unstable with only pair of unstable eigenvalues $0.0089 \pm 0.2932i$. Some corresponding normalized participation factors associated with this pair of unstable modes are listed in Table 3.
- For (0.8, 0.4) in region (4), both of the market-only system and the coupled system are unstable. The only one pair of unstable modes for ideal market-only dynamics is $0.0501 \pm 0.4014i$, which are mainly associated with system energy imbalance and power price with the corresponding normalized participation factors 1.00 and 0.30 respectively. The only one pair of unstable modes for the coupled system is $0.0379 \pm 0.3025i$. Some corresponding normalized participation factors associated with these two eigenvalues are listed in Table 4.

8 Conclusions

This paper begins from a simple, intuitive dynamic model for consumer/producer response and price setting in an electric power market. Energy imbalance (the integral of power supply and demand mismatch) is hypothesized as the key driving term for updating price. It is argued that a weighted average frequency provides a close approximation to energy imbalance physically measurable. This allows the construction of a coupled dynamics model that encompasses consumer/supplier response, market price update, and the physical power/system dynamics.

The key contribution of the paper is to examine the dynamic impact of parameters in the market design, such as the sensitivity of price to energy imbalance, or to its surrogate, average frequency error. In the market-only dynamic model, the system appears able to tolerate high sensitivity of market price to energy imbalance. In the more accurate coupled model that includes physical dynamics, this sensitivity behaves like a feedback gain, and its value must be much smaller in order to maintain a stable system.

The implications of this result are significant: those designing the power exchange policies and rules for ISOs for deregulated power market must accommodate to the dynamic needs of the system, and those designing system electromechanical controls must take into consideration the conditions that will be imposed on the power system by operation in a market-driven environment.

9 Acknowledgement/Disclosure

This research is supported by Subcontract No. 35352-6087 from Cornell University, under WO 8333-04 from the Electric Power Research Institute and the US Army Research Office. This report has not been reviewed to determine whether it contains patentable subject material, nor has the accuracy of its information or conclusions been evaluated by EPRI.

Appendix: Market Dynamics Data for New England System (see Figure 9)

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Table 3: Selected normalized participation factors associated with the sample point in region (3) for the coupled system ($\tau_\lambda = 0.15$, k_E=0.3, the participation factor associated with price λ is 0.13)

Bus #	30	31	32	33	34	35	36	37	38	39
P_g	0.20	0.19	0.27	0.19	0.26	0.18	0.22	0.19	0.22	0.20
δ	0.078	0.037	0.054	0.049	0.069	0.0078	0.087	0.059	0.12	0.36
ω	0.42	0.29	0.35	0.27	0.25	0.31	0.25	0.23	0.32	1.00
P_m	0.22	0.20	0.27	0.20	0.27	0.19	0.24	0.20	0.23	0.22

Table 4: Selected normalized participation factors associated with the sample point in region (4) for the coupled system ($\tau_\lambda = 0.8$, k_E=0.4, the participation factor associated with price λ is 0.76)

Bus #	30	31	32	33	34	35	36	37	38	39
P_g	0.21	0.20	0.28	0.20	0.27	0.19	0.23	0.20	0.23	0.21
δ	0.075	0.037	0.050	0.048	0.061	0.0084	0.079	0.056	0.11	0.33
ω	0.42	0.29	0.36	0.27	0.25	0.31	0.25	0.23	0.32	1.00
P_m	0.20	0.19	0.26	0.19	0.25	0.18	0.22	0.19	0.21	0.20

```
#Bus)(--Tau_g--)(---cg---)(---bg---)(---Kg---)
   30  35       0.8       30.00     0.0
   31  30       0.7       35.99     0.0
   32  25       0.7       35.45     0.0
   33  30       0.8       34.94     0.0
   34  25       0.8       35.94     0.0
   35  30       0.8       34.80     0.0
   36  30       1.0       34.40     0.0
   37  30       0.8       35.68     0.0
   38  30       0.8       33.36     0.0
   39  35       0.6       34.00     0.0
 -999
#Bus)(--Tau_d--)(---cd---)(---bd---)(---Kd---)
    3  150      -0.8      42.58     0.0
    4  150      -0.7      43.50     0.0
    7  150      -0.6      41.40     0.0
    8  155      -0.6      43.13     0.0
   12  150      -0.8      40.07     0.0
   15  150      -0.8      42.56     0.0
   16  155      -0.7      42.31     0.0
   18  150      -0.6      40.95     0.0
   20  155      -0.8      45.44     0.0
   21  150      -0.7      41.92     0.0
   23  150      -0.7      41.73     0.0
   24  155      -0.6      41.85     0.0
   25  155      -0.6      41.34     0.0
   26  150      -0.7      40.97     0.0
   27  150      -0.7      41.97     0.0
   28  150      -0.8      41.65     0.0
   29  160      -0.7      41.98     0.0
 -999
#(-T_lambda-)(--Ke--)(--Kp--)
 0.2           0.01     1
```

Figure 9*: Market dynamics data for New England system*

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