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Operation and Control in a Competitive Market:
Distributed Generation in a Restructured Industry

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Abstract

The prospect of independent ownership for distributed technologies is being encouraged by the current deregulation of the industry, and it is possible that the new generators will be independently operated as well as independently owned. The siting of numerous small-scale generators in distribution feeders is likely to have an impact on the operations and control of the power system, a system designed to operate with large, central generating facilities. In response to the new and potentially conflicting economic and technical demands of a growing number of independent players, the power system may require new means for coordinating system operations. Price signals are one mechanism available to coordinate the operation of the power system in the emerging competitive market.

This paper discusses the integration of distributed generation into the operations of the distribution system. It first discusses the engineering concern that numerous distributed generators might adversely impact system stability and reliability, and proposes methods to address these issues. The paper then demonstrates the ability of the distributed generators to participate in the competitive energy and ancillary services markets, by responding to a price signal that coordinates both the engineering and the economic aspects of distributed generator operation in a restructured power system.

Introduction

The growing interest in small, distributed generators represent one component of the broader theoretical concept of a distributed utility. This concept focuses on the evolution of the power system as it responds to technological advances, industry restructuring and the uncertainties associated with these changes. As a result of the relative newness of the idea and the variety of related projects, the term distributed utility has already come to be used differently by various practitioners. For example, the emphasis can be on demand side management, generation, storage, automation or any combination of these. Generators of interest might be new, alternative technologies such as fuel cells and storage facilities, or fossil fuel technologies (of relatively smaller capacity), such as gas turbines and cogeneration facilities, or renewable energy technologies or any combination of these. The plant capacity of interest can range from tens of kilowatts to 25 MW or more. And finally the siting options can include the sub-transmission system, urban or suburban distribution systems, or more remote rural locations. These differences aside, the commonalities in the usage of the terms distributed generation or distributed utility lie in the assumption of increased interest in alternative small-scale technologies which are installed in closer proximity to the load than is current practice. For the purposes of this paper the term distributed generation refers to small generators (500kW to 1MW) located in the distribution system (i.e. the radial component) of a traditional electric power utility.

This paper discusses both engineering and economic market coordination issues associated with what some consider to be unproven technologies. It is important to recognize that any discussion of the long term benefits of distributed generation—financial and economic—necessarily assumes that the power system will continue to be stable and reliable. Will numerous distributed generators adversely impact system stability? Will voltage and frequency remain within specified bounds of their nominal values? Will all load will be met with specified (high) probability?

To address these concerns, the first section of this paper demonstrates that there are some situations where this assumption of continued stable operation may be unfounded. This fact suggests that close attention should be paid to the technical characteristics of distributed generators if large numbers are to be successfully incorporated into the power system. The paper next describes a possible structure for a competitive energy and ancillary services market with many independent players. The final section in the paper demonstrates the role of price in coordinating the operation of distributed generators in the distribution system of a restructured power system.

The role of prices in coordinating both the technical and economic operations of a power system with distributed generation, as described in this paper, is demonstrated through the use of simulations with a sample distribution system operating in a competitive market for energy. Using the model, with the introduction of a price feedback signal from the market coordinator or the ISO, we show how distributed generators may be coordinated such that the system will not always require centralized control to maintain reliability and stability.

Technical Issues for Distributed Generation

Much of the attention distributed generators receive is focused on the long term benefits they offer in terms of their economic and financial characteristics and potential for promoting efficient system expansion (whether a central utility or independent project). Engineering issues associated with distributed generators are tied to phenomena which evolve over a much shorter time frame, such as frequency and voltage stability, automatic generation control (AGC), spinning reserve, load following, and other ancillary services. It is not the objective of this section to focus on ancillary services for a future restructured industry---a discussion of greater relevance to the high voltage transmission system than to the distribution system. Nonetheless, with the potential of siting small scale generators in the distribution system, a subset of these concerns---specifically the issues of stability and reliability within the local systems---merits examination. Only after system stability over the short time frame is assured can the discussion move to longer time frames and a discussion of the economic operation of a radial system with distributed generation.

To explore the stability concerns, a model with examples of several distributed generators operating within the distribution system is developed. This model is used to demonstrate that it is possible, in some operating situations, for the distribution system to go unstable. It is important to note that these situations are unexpected since similar generator configurations on the high voltage grid would *not* result in stability problems. Several approaches for ensuring system stability in these situations are discussed at the end of this section.

Distribution System Characteristics

It is important to identify the differences between the distribution and the high voltage transmission systems in order to understand why the means for maintaining stability differ. Most existing distribution systems were designed to passively distribute energy generated on the high voltage grid to consumers connected to the local system. Therefore, one feature of the distribution system is that typically it contains only consumers, or load buses, and not power generators or other active supply sources. In such a system, power flows in one direction only---from the substation to consumers. A second related difference arises from the physical structure of the system. The traditional power distribution system is radial, or looped, in contrast to the highly meshed network of the high voltage transmission grid. For a distribution system then, there is one, or at most two, paths to each bus, as opposed to multiple paths to each bus in the transmission grid. A third important distinction lies in the electrical properties of the power lines themselves. High voltage lines have relatively low resistance while low voltage lines in the distribution system have a larger relative resistance. These differences affect the strength and number of interconnections between generators and load buses, and therefore the degree to which the interconnected generators can affect one another and the connected loads.

The final distinction between the distribution and transmission systems is the extent and type of control framework historically required to maintain system stability and desired operation. Supervisory Control and Data Acquisition (SCADA) systems and Automatic Generation Control (AGC) are two well known and long standing control frameworks commonly part of power system control and operation strategies, which typically are implemented exclusively at the high voltage transmission level. Limited automatic control and data gathering are being gradually introduced into the distribution system, however such automation is not yet common at the distribution level in the United States. The modeling in this paper demonstrates that any meaningful presence of distributed generation will require a concurrent increase in the extent and sophistication of both the control framework and data acquisition systems. As we show, until such control is implemented, there could be unexpected and undesirable consequences of installing multiple distributed generators in existing distribution systems.

Developing a Dynamic System Model

The established engineering methods for maintaining stable system operation have been designed to meet the requirements of generators that are traditionally located at the transmission level. The discussion which follows focuses on frequency stability in the *distribution system*, and analyzes whether the integration of multiple distributed generators into a radial distribution system can adversely affect system stability? If large numbers of distributed generators do affect system performance, then it is important to explore modifications that may be required to the existing generator operations or control strategies in order to maintain system stability.

To explore the system dynamics of interest, a model is developed below and then used for simulating dynamic interactions of distributed generators in a distribution system. The first step in developing the model is to identify the variables of interest. For the purposes of the analysis of frequency stability, the primary values of interest at each bus, i, are frequency, ω_{Gi}, and real power output, P_{Gi}. Frequency stability is analyzed by tracking the frequency at each bus as it evolves over time. If the frequency values either remain constant (at the nominal 60 Hz value) or converge to a different equilibrium value, then the system frequency is stable. On the other hand, if a small disturbance at one bus in the system, such as an increase or decrease in demand, causes the frequency at one or more other buses to diverge from an equilibrium, then the system is defined as being unstable. On an actual system, such an event represents loss of synchronism.

Mathematically, the dynamics of the system are represented through as series of linear, differential equations, expressing the time evolution of the system values of interest. These system values are referred to as state variables since they capture everything of interest about the current state of the system. For each state variable, the model contains one equation that represents the relationship between that variable and all other variables in the system.

A simple model for a combustion turbine-generator, which includes both ω_{Gi}, and P_{Gi} as identified above, is developed below. In the first step, ω_G is identified as the state variable for the generator, V_{CE} is the variable for the fuel controller, and W_F and W_{Fd} are both necessary to represent the fuel flow. The set of combustion turbine-generator equations is:

$$\begin{aligned} M\dot{\varpi}_G &= -D\varpi_G + cW_F - P_G \\ b\dot{V}_{CE} &= -K_D\varpi_G - V_{CE} \\ \dot{W}_F &= W_{Fd} \\ \alpha\dot{W}_{Fd} &= aV_{CE} - \delta W_F - \beta W_{Fd} \end{aligned} \tag{1}$$

In these equations *M* is the inertia constant, *D* is the damping coefficient and the '·' signifies time rate of change, *dx/dt*. The remaining parameters are the coefficients for the linear relationship between the state variables specified. They are defined in references (Calovic 1971, IEEE 1973, IEEE 1991). Additional distributed generator models can be found in (Cardell 1997).

To build the complete system model, the individual generator models are coupled to each other via the distribution system. To achieve this coupling each set of equations representing a local generator is expanded to include the system coupling variable, selected to be power output or P_{Gi}. Beginning with the linearized load flow equations, the following differential equation for real power can be derived (Liu 1994).

$$\dot{P}_G = \mathbf{K}\varpi_G + \mathbf{L}\dot{P}_L \tag{2}$$

In this equation $\dot{P}_L$ represents a load disturbance (or the change in load with respect to time, which requires the '·' notation) and is the input variable to the system of equations. The matrices **K** and **L** are derived from the Jacobian matrix for the distribution system.

Expressed in standard format the full system of equations for the model is written as

$$\begin{aligned} M\dot{\varpi}_G &= -D\varpi_G + cW_F - P_G \\ b\dot{V}_{CE} &= -K_D\varpi_G - V_{CE} \\ \dot{W}_F &= W_{Fd} \\ \alpha\dot{W}_{Fd} &= aV_{CE} - \delta W_F - \beta W_{Fd} \\ \dot{P}_G &= \mathbf{K}\varpi_G + \mathbf{L}\dot{P}_L \end{aligned} \tag{3}$$

or more compactly as

$$\dot{\mathbf{x}} = \mathbf{A}\mathbf{x} + \mathbf{B}\dot{P}_L \tag{4}$$

where **x** represents the vector of state variables related to the system dynamics (specifically ω_G, V_{CE}, W_F, W_{Fd} and P_G for this example), and **A** and **B** are constant, non-zero matrices of the parameters expressing the linear relationship between these variables. If all load values remain constant then the input vector $\dot{P}_L$ is identically zero. Whenever a load increases or decreases, a disturbance results, which in the model is expressed as a non-zero value for $\dot{P}_L$. For the non-dispatchable technologies such as wind and photovoltaics a fluctuation in the wind or solar resource represents a system disturbance. The model in this form is used for the simulations below.

Sample Distributed Generation Systems

The distribution network used for the examples in this paper is shown in Figure 1, the data for which can be found in (Grainger 1985, Santoso 1989). Only the buses with generators and the load disturbance are labeled. All other buses, 25 of the 31, are static load buses. (Note that the total load is dispersed throughout the system, with every unlabeled node representing a static load bus.) Total load on the system is 14 MW and the total capacity from distributed generation varies from 1.4 MW to 2.5 MW in the examples presented. To explore whether multiple distributed generators could adversely impact system stability we use the model described above to simulate the dynamics of a distribution system under different scenarios which vary the distribution of load and the location, types and numbers of distributed generators connected to the system.

The first example has a 700 kW steam turbine at generator 1, and a 700 kW combustion turbine at generator 2 (as well as a slack bus[1] at the substation). The load disturbance is a small increase in demand at time equals 2 seconds. Figure 2 shows the *frequency deviation* from the equilibrium point at all generator buses for this system. (The unlabeled line in the figure represents the frequency at the substation, or slack bus.) The system is stable so long as the frequency deviation over time converges to an equilibrium value. The rotor frequency for the small turbines is seen to oscillate around the nominal 60Hz frequency, and then converge to a slightly slower value. The behavior demonstrated by the system in Figure 2 is the desired behavior.

The system is next modeled with four combustion turbines, ranging from 500 kW to 750 kW, (with a total of 2.5 MW) distributed throughout the system, as identified in Figure 1. The turbines have slightly different values for the controller gains (K_D in Equation (1)), all within the ranges as specified in (Hannett and Khan 1993, Hannett, Jee and Fardanesh 1995, Rowen 1983). The frequency behavior of two of these generators, along with the slack bus, is plotted in Figure 3. (The frequency deviations of the remaining generators are not plotted to avoid confusion in the figure.) This figure clearly demonstrates

[1] A slack bus is an artifact of the need to maintain power flow balance on the system. Load flow analyses include one bus where the real power remains unspecified, a bus designated to take up the 'slack' and balance the power flow on the system. This bus is referred to as the slack bus, which in this paper is used to represent the bulk power system. This is conceptually consistent since the bulk power system is assumed to supply any power necessary to maintain the power balance within the distribution system.

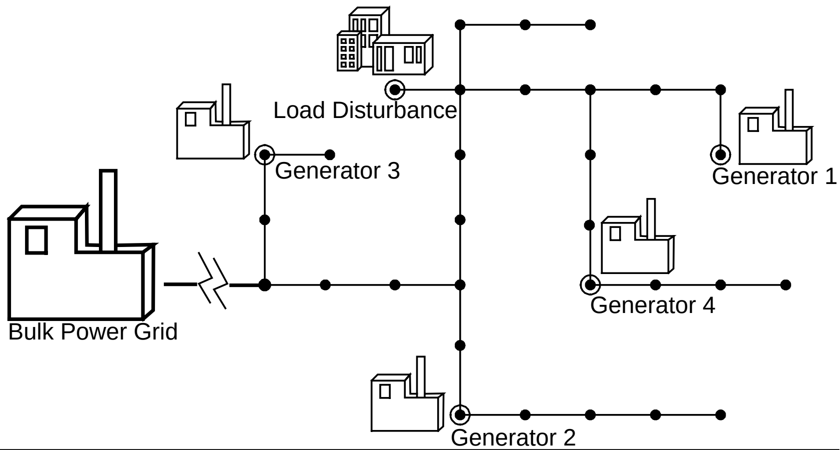

Figure 0: Sample Distribution System (Static load distributed across every node)

that local system frequency in this example becomes unstable given the same load disturbance as in the first example. It is significant to note that the system remains stable when only two combustion turbines are in the system. It is not until there are four generators that the instability is seen, suggesting that at least for frequency stability technical problems may arise only as the number of distributed generators increases.

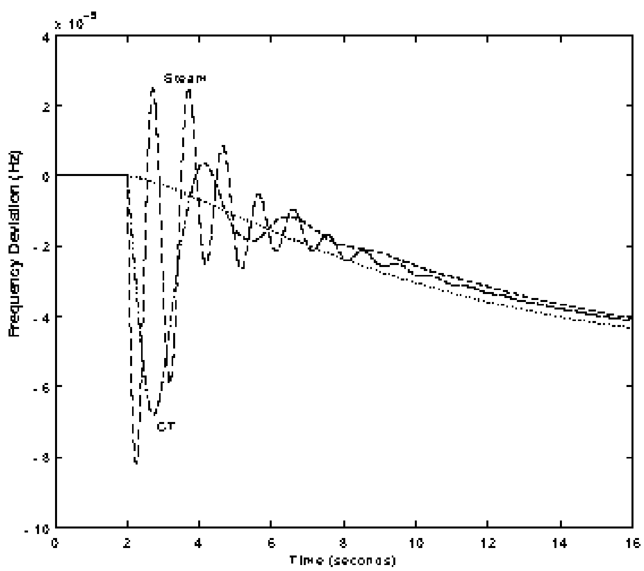

Figure 0: Base Case–Frequency Deviation After Load Disturbance

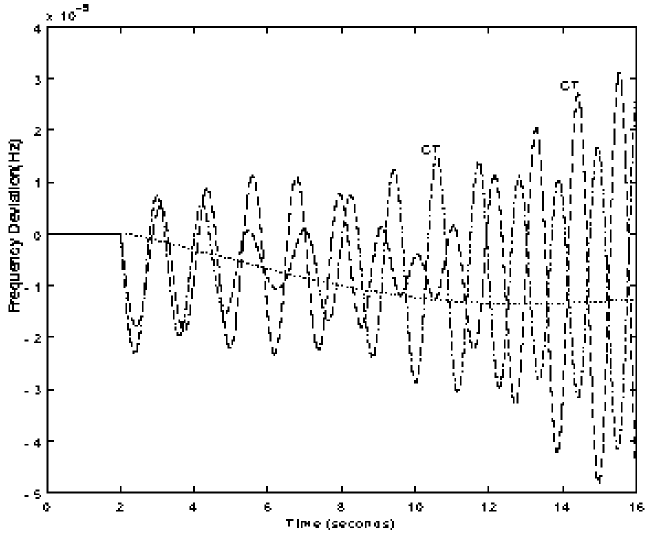

Figure 0: Frequency Deviation from Equilibrium for System with Four Combustion Turbines

In the third example, when a single hydroelectric generator is modeled as generator 1 the frequency also becomes unstable. With a combustion turbine added to the system at generator 2 (both generators of capacity 750 kW), the instability caused by the hydroelectric plant creates instability at the combustion turbine bus as well. See Figure 4. The instability found in the above example can be avoided by carefully tuning the generator to the specific system. Note that the hydro plant as modeled has all parameters set within the ranges as established for existing small hydro facilities. The point of this example is not that hydro or any other small scale generating technology will automatically cause frequency instability, but rather that it is possible for them to do so unless close attention is paid to the new situation represented by siting multiple generators in a radial distribution system. Note also that the instability remains local to the distribution system in all examples; the slack bus frequency never diverges from an equilibrium value, as is consistent with modeling the bulk power system as a slack bus.

Sources of System Instability

The cause of the frequency instability in the distributed generation systems is discussed next. Two properties of the distributed generation systems are seen to impact the nature of the system dynamics, such that the distribution system may respond differently to disturbances than does the transmission grid.

First, in evaluation of the high voltage transmission system it is correctly assumed that the local generator dynamics—i.e. variations in frequency, ϖ—are slow relative to the dynamics of the transmission network itself. The implication of this assumption is that a change in a local state variable (frequency) at any bus is instantaneously transmitted through the system, without any noticeable affect of the network itself on the disturbance or the local generator dynamics.

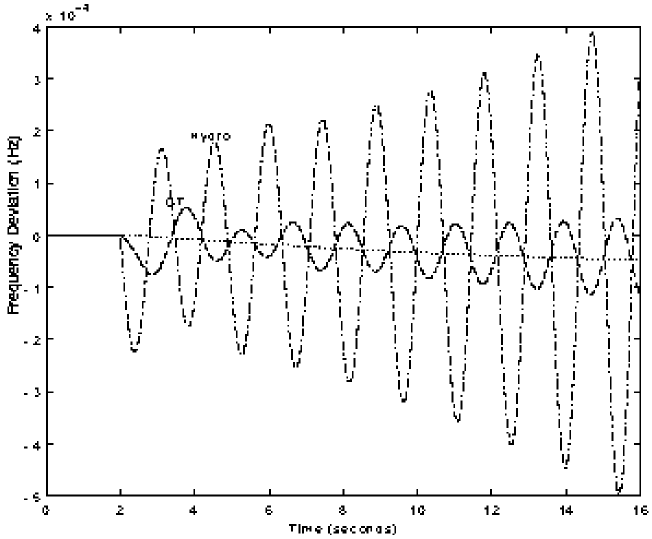

Figure 0: Frequency Deviation with Hydroelectric and Combustion Turbines

As described above the distribution system has relatively high impedance and a radial structure, which translates to weaker interconnections between all buses. The significance of this can be better understood by drawing an analogy to a mechanical spring and mass system where the spring represents a power line and the mass a generator rotor. In the mechanical system if the mass is displaced, it is restored to its equilibrium position more or less quickly depending on the strength of the spring. In a power system, a frequency change implies a change in the relative positions of the generator rotors. The rotors will be restored to their synchronous positions more or less quickly depending on the strength of the interconnection (where a large impedance represents a weak interconnection).

A second distinction is that the generators on the high voltage grid are very large with correspondingly large mechanical inertias, in comparison to the small distributed generators. The smaller machine inertias compound the network affect on the local frequency by being too small to effectively counteract the oscillations from the disturbance. These observations of large line impedance and small inertias are not surprising. What is unexpected is that they are significant enough to potentially affect stability within the distribution system.

Methods for Stabilizing the System

For the examples discussed in this paper the local dynamics of all generators independently and the network itself are stable (which can be verified by performing an eigenvalue analysis). Nonetheless, some system configurations, such as those presented above, may exhibit instability. This result has practical application in defining a process to stabilize the system. Currently, for the high voltage transmission network it is assumed that system stability can be ensured if each generator is stabilized individually against the system (represented as an infinite or slack bus) and then connected to the network. The instability found with the examples in this paper suggest that the methodology necessary for initially stabilizing a distributed generation system could differ from this current practice.

The stability problem suggests that local control design and/or ranges for generator settings may call for renewed attention to ensure that stability will be maintained in a radial distribution system with numerous distributed generators. A general method for specifying ranges for the values of local parameters (the linearized coefficients on the right hand side of the Equations (1) and (3)) is to calculate eigenvalue sensitivity to these parameters, for the unstable system eigenvalues. The sensitivity matrix, $\mathbf{S}_i$, for the i^th^ eigenvalue is defined to be

$$S_i = \frac{\partial \lambda_i}{\partial a_{jk}} = w_i v_i \qquad (5)$$

where the λ_i are the eigenvalues of the system, the a_{jk} are the local control parameters, and w_i and v_i are the left and right eigenvectors respectively for the i^{th} eigenvalue (where v_i is a row vector).

This matrix is calculated for the unstable eigenvalues for each system with instability, examples of which are shown in Figures 3 and 4. The sensitivity matrix shows that for the systems with a hydroelectric plant, the unstable behavior (or the unstable mode) is most sensitive to the parameter representing the time constant for the gate position or opening, suggesting that this time constant would be a good value to adjust. Figure 5 shows the system of Figure 4, with the time constant for the gate opening of the hydro plant increased so that it can not react as quickly to a disturbance, preventing it from resonating with the oscillations. (The unlabeled, dotted line on this and the following figure represents the substation or slack bus.) Note that although this solution solves the stability problem, it also serves to challenge one of the anticipated benefits of distributed generation, specifically that the fast response capabilities of small generators would be beneficial in responding quickly to changes in demand and so help minimize any disturbance. A second parameter found to significantly affect the stability is the inertia constant, M, which implies a potential stability benefit from specifying a minimum inertia, or size of plant installed.

For the system with only combustion turbines (Figure 3), the greatest sensitivity is found in the gain of the fuel system controller. (See (Rowen 1983) for detailed explanation of these parameters.) When this gain is decreased, the system is stabilized. Note that the system modeled for Figure 4 has both a hydro generator and a combustion turbine, and that the gain in the CT fuel system controller is *not* identified as a parameter to which the instability is significantly sensitive for

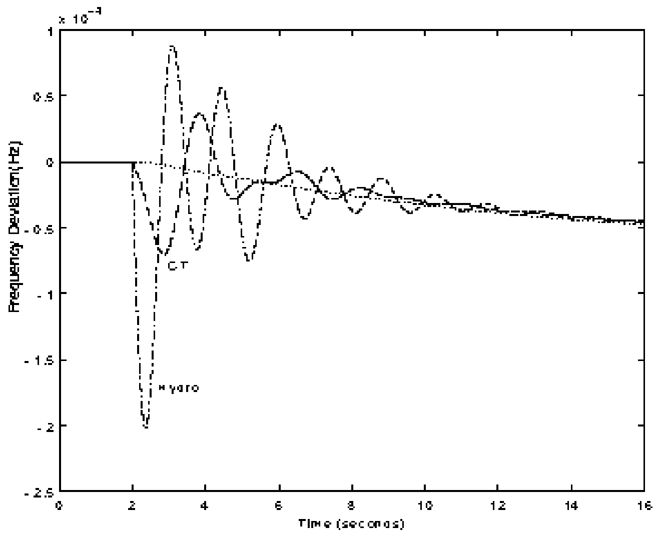

Figure 0: Hydro Gate Opening Time Constant Increased

this system configuration—a finding which demonstrates that the instability is a system phenomenon, and not caused by only one generator or generator type.

Summary

The first part of this paper has described the modeling approach used to simulate the frequency dynamics for a distribution system with small, distributed generators. Instability was found, and examining the sensitivity matrix suggested various methods for stabilizing the system, requiring that close attention be paid to local control parameters—time constants and gains, or to generator selection—machine size or inertia. It was also demonstrated, that in some cases instability may only occur as the number of distributed generators in the distribution system increases.

The frequency issues raised in the previous section are not new to power systems, but are new to the distribution system. One difference in the solutions suggested here from those currently implemented on the high voltage grid is the focus on using the local generator controls, including governors, to secure frequency stability. At the high voltage level, local controls such as governors react more slowly and so are not relied upon for maintaining system stability. In contrast, the analysis in this section has shown that local generator governors *can* be used at the distribution level to ensure frequency stability. A drawback of this sensitivity to the governor settings is that at the distribution level generators may not be able to turn off their governors and drift with the system frequency as they can at the transmission level.

A deregulated capacity market incorporating distributed generators is more consistent with decentralized than with centralized control. However, the methods for stabilizing the system introduced in this section do require some degree of centralized oversight in determining governor standards or in generator selection. It is important to point out that the frequency concerns for the distribution system raised here are easily addressed. It is vital that the extra stability analysis is performed though, as the penetration of distributed generators increases, so that the potential frequency problems are successfully avoided.

System Coordination in a Competitive Market

Given these methods to ensure system stability we turn to a discussion of methods for a competitive energy market to operate with multiple, independent distributed generators. In the industry today independent power producers are paid based on long term contracts with utilities. This process has required the utility and regulators to have extensive information on each generating unit in order to determine the optimal contract price. This operational dynamic is inconsistent with the competitive market model we expect to see in the future.

This section first discusses potential market structures for the future electric power industry. This is followed by specific examples of distributed generators responding to a price feedback signal which functions to coordinate distributed generator operation in a competitive market structure.

The Energy and Services Markets

The concept of an Independent System Operator (ISO) playing a major role in the restructured Electric Supply Industry (ESI) has been a part of the restructuring proposals in many countries. It is agreed that the ISO must be a regulated player in a largely unregulated commodity market for both economic and engineering efficiency to be assured. Not only is this independence critical to assure that the functions of the market proceed without any prejudicial transactions, or the potential for those transactions, but it is critical to provide the proper economic incentives for the ISO to maintain system reliability and provide for operation of the transmission grid.

Engineering realities play a critical role in the manner in which the ISO will operate. An electricity commodity market can and will work very efficiently in the time frame greater than one hour – the time domain on the left hand side of Figure 6. The task of the ISO is to plan for and implement the operational decisions required to “keep the lights on” in the time frame of less than one hour – the time domain on the right hand side of the figure. The characteristics of the operations of the ISO are vastly different from those of the commercial commodity market. The commodity being traded in the commercial market is energy (kWh). This is the product that is bought and sold in the forward markets and is traded and cleared in the spot market. It is critical to note that while, in the past we were conditioned to believe that all kWhs were the same, participants in the market now understand (and trade) in energy markets that are differentiated by both time and location (Fernando 1995). In addition suppliers are rebundling energy into packages that may be sold as clean, or green, or interruptible. Under the scenario we present, the commercial market can trade until an hour (or ½ hour) before delivery. Any symmetric imbalances from traders who are shown to be long or short after the hourly commercial market has closed can be corrected in the ex-post clearing market—the furthest right box in Figure 6.

The critical element of Figure 6 is the function of the ISO and the resources required by the ISO to maintain reliability, security and stability. In a market structure in which participants are responsible for balancing their energy supplies and demands, the ISO is responsible for securing additional capacity resources (generally under short term contract) that it can call upon if needed to

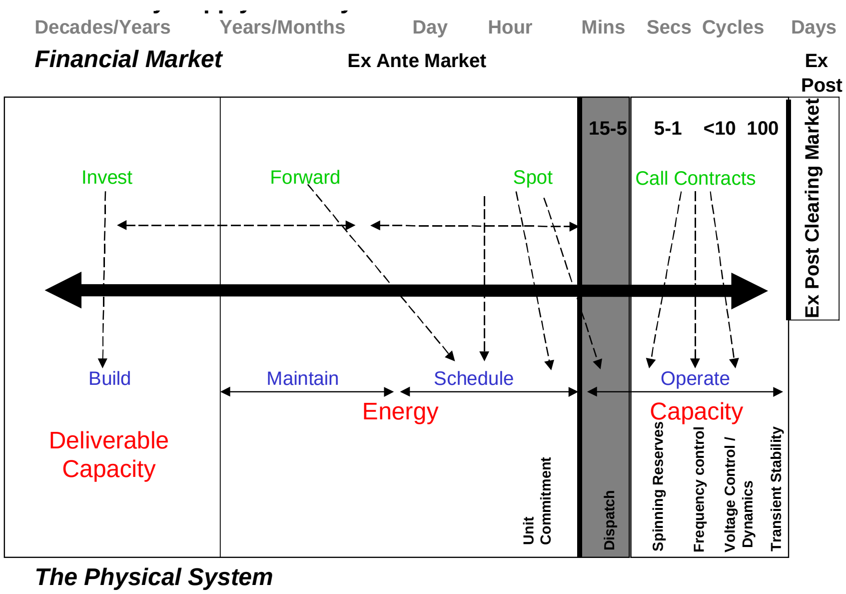

Figure 0: Time Separation for Events in the Electric Supply Industry

supply the ancillary services or reserves necessary to meet its operational obligations. The resources that it maintains are thus made available as necessary, to support the trading of the products in the commercial market which focuses on the delivery of energy.

The market structure envisioned in this paper assumes that these services can be supplied competitively, and further that a competitive market will be developed at the distribution level. It is assumed that distributed generators will be allowed not only to enter into contracts at the wholesale and retail levels, and participate in the commercial energy market, but also provide ancillary services to the ISO and local customers on a competitive basis.

This transition of the electric supply industry toward greater competition in the generation sector will require a parallel transition in the control and operation of generators from the current centralized structure to a more decentralized and market driven framework. A price signal is a basic economic tool for coordinating a competitive market. One way for distributed generators to operate in the future competitive markets is for their local controls to be designed to respond, in real time, to a price signal.

With this potential future model for the energy and services market in mind, the paper now focuses on short run operational dynamics and the role of distributed generators in both of these markets.

Objectives of the Closed Loop Price Signal

The price signal introduced below is a closed loop signal (i.e. one that incorporates feedback) rather than an open loop signal, as most price signals in the electric supply industry are today. One objective in introducing a closed loop price signal to the generation sector is to aid in the creation of the desired competitive market. Market based institutions must be purposefully created as regulatory oversight is decreased in the generation sector, or it is likely that the sector will simply become an unregulated monopoly rather than a competitive market. A price signal expresses to consumers and suppliers the efficient levels of demand and supply. A closed loop price signal will capture the market clearing dynamic of a competitive market in the dynamics of the feedback control, and so incorporate market prices into system *control* decisions as well as in siting and investment decisions.

A second goal of the price signal is to provide a decentralized control mechanism which allows each generator to operate independently while also providing an incentive for the generators in aggregate to produce at the efficient level. The price signal facilitates the creation of a decentralized system in which distributed generators are free to act independently, required neither to give control nor any private information to a centralized authority. The objective of the price model is to *demonstrate* that a market-based price signal can be used in conjunction with the existing bulk flow market price to successfully control and coordinate a distribution system (Cardell 1997).

The Role of the Closed Loop Price Signal in the Market

The future power system is likely to have competitive markets for both energy and ancillary services. In the proposed price framework the basic piece of information communicated to the distributed generators from the ISO and the market coordinator (or Power Exchange, PX) is the spot price of energy and/or services. This spot price corresponds to the price of the scheduled power flows as determined by the ISO and PX.

In the price framework proposed in this paper, the full price communicated to the distributed generators via the substation is assumed to represent both the spot price and a component to account for deviations from the scheduled power flows. The magnitude of the price variable in the model presented below represents this component for the deviation from equilibrium and *not* the full market or absolute value. The full price of energy in the market can thus be expressed as

$$\rho_{\text{base}} \pm \Delta\rho \tag{6}$$

where $\Delta\rho$ is the quantity determined by the price based control loop presented in this section, and ρ_{base} is the spot price of the scheduled, bulk power flows. In the context of current power system operation, $\Delta\rho$ would likely be calculated *after* all flows and power output levels are known, or else forecasted using either expected values or historical values. In contrast to this approach, the price control model derived in this section determines $\Delta\rho$ dynamically, via feedback, and without direct, centralized control.

The price signal can be operated in a flexible time scale. Every k minutes the market or system price, ρ_{base}, is updated to reflect the current price of power delivered to the distribution system. The time step k could be as long as 30 minutes or 1 hour, and so coincide with the spot market as typically defined in the ongoing industry restructuring debate. To capture system regulation needs, and provide market incentives for small generators to provide ancillary services though, the time step k for $\Delta\rho$ must be defined for a shorter time step, such as 5 minutes. A significant aspect of the proposed price control structure is that the mathematical representation and corresponding system response are identical whether it is the real-time energy market or the services market that is being modeled. This mirrors events in the actual power system since *inside* the 30 minute or 1 hour window of the traditional spot market, a change in the demand for energy *is* the source of the system demand for ancillary services. At this time scale both the services and short term energy markets are driven by deviations from scheduled power flow, and are differentiated only in the length of the time step k, as well as in the perceived *cause* of the system disturbance.

Price based controls are typically precluded from acting this quickly due to the longer time frame assumed necessary for market interactions. It is not a theoretical constraint however that prevents the price feedback from being implemented in the shorter time step—a price signal is capable of acting in this short time period. It is within this shorter time window that system regulation is an issue, and that controls act to stabilize the system. The price signal model demonstrates that both the short run energy and the services markets can be operated competitively.

Anticipated Generator Response to Price Feedback

The closed loop price signal corresponds to the marginal revenue earned by a participating distributed generator, and as dictated by economic theory the competitive suppliers will produce at the level where their marginal cost equals marginal revenue. The price model incorporates this economic objective (*MC=MR*) into the short run operating strategies of the individual distributed generators such that the generators respond automatically to changes in the system price by altering their output until their marginal costs of production equal the spot price.

Figures 7 through 9 demonstrate the anticipated generator response to the price signal. Figure 7 shows a system disturbance on the test system of Figure 1, occurring at time t = 8 minutes, and the resulting increase in generator output without the price signal implemented. To compare the system response with and without the price signal, Figure 8 first shows this system output and corresponding price deviations without the price feedback implemented. Figure 9 then shows the output and price deviations with the price signal implemented. The price signal, acting at time t = 10 minutes, causes the generators to adjust their output so that the final generation levels are all close to the system price (represented by the lower, dotted line on the graphs). The simulations will be analyzed more fully at the end of this section after the price model has been developed.

Developing The Closed Loop Price Signal Model

In the power system today, there is no closed loop market signal integrated into system operating decisions. Industry restructuring, and particularly the deregulation of generation, is opening the power sector to market forces. As part of this process, price-based market signals will be integrated into the operating

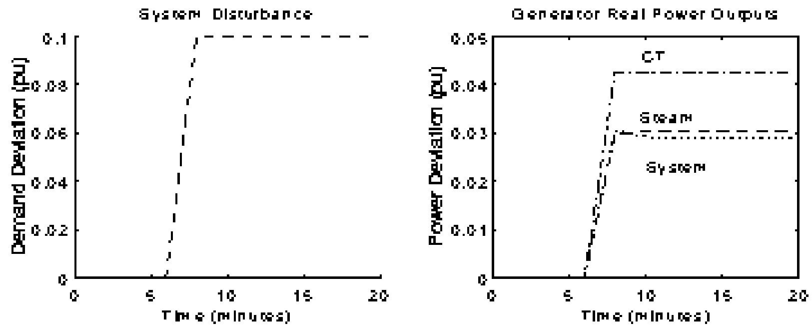

Figure 0: Load Disturbance with Corresponding Increase in Power Output (No Price Signal)

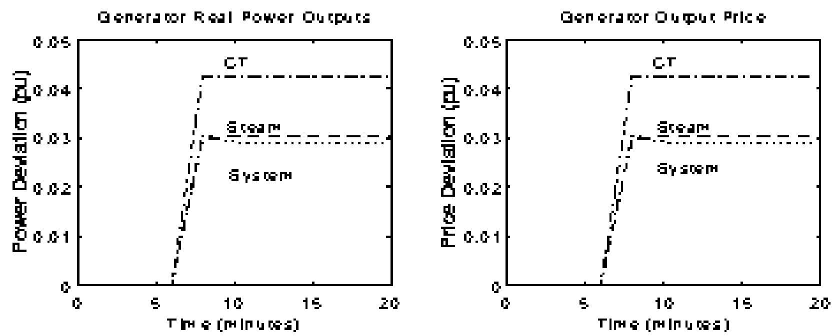

Figure 0: Power Deviation and Corresponding Price Deviation *Without* Price Signal

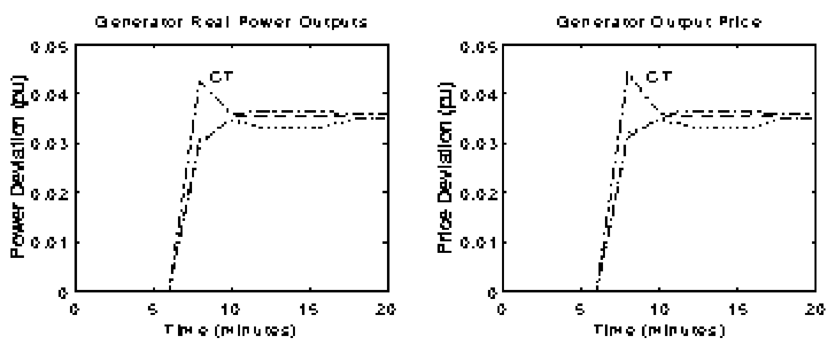

Figure 0: Power Deviation and Corresponding Price Deviation *With* Price Signal

decisions at all levels of the power system. An hourly spot market is currently being designed in the regulatory and policy arena, with extensive input from other industry stakeholders. There is at present however, little effort to make this hourly spot market a *closed loop* structure. Instead the spot market development is following the pattern established in other countries as well as in some areas of this country, by setting the hourly schedule a day in advance, and determining the price as an *open loop* signal. In addition to the lack of effort in designing a closed loop signal, there is not yet effort to integrate market forces into the operations and control decisions on a time scale shorter than one hour, such as every five or ten minutes, or even shorter as is consistent with the dynamics of system regulation.

This section develops the mathematical framework for a closed loop price signal, designed to coordinate distributed generators as they participate in both the short run energy market and the ancillary services market. A price signal of this form is of interest because it creates the means for competitive market forces to guide operating and control decisions in real-time. Assuming there are no market failures, the efficiency of the power system will improve as the reliance on market forces increases.

The development of the closed loop price model begins by expressing the cost of power generation in terms of the state variables in the generator equations. Cost can be incorporated into the state space generator models by writing an output equation to capture the variable costs associated with generating power from any given technology. Referring to the generator model in Equation (3), the cost equation for a combustion turbine would be written as

$$c = c_w \varpi_G + c_V V_{CE} + c_W W_F + c_{Wd} W_{Fd} + c_g P_G \tag{7}$$

The coefficients in this equation represent the marginal cost associated with each piece of equipment or process represented by the specified state variable. In particular, c_g is the marginal fuel cost. The significance of the values of the coefficients in the cost equation lies not in the absolute values chosen, but rather in the relative values of the coefficients between the different technologies and distributed generators. It is the relative cost values that capture the real-time differences in using one technology before another. This interpretation of the cost coefficients is valid for all generators modeled except the slack bus. The cost equation for the slack bus is interpreted as representing the cost to the bulk system of generating the power which is supplied to the distribution system. This system cost, and the related price, are represented as ρ_{sys} in the discussion below.

The generators and the system will respond to the price signal at specific intervals, indicating that the closed loop price signal is best modeled in discrete time. To develop the dynamic form of the equation, the cost equation is added to the set of differential equations for the system (Equation (3)), all time derivatives are set equal to zero, and the equations are solved for cost. Assuming for now that the markets are perfectly competitive, price is assumed to be equal to marginal cost, so that the discrete time cost equation can be expressed in terms of price as

$$x_\rho[\mathrm{k}+1] = x_\rho[\mathrm{k}] + \mathbf{C}_1 u_\rho[\mathrm{k}] + \mathbf{C}_2(\varpi_G[\mathrm{k}+1] - \varpi_G[\mathrm{k}]) \tag{8}$$

where x_ρ is the price-based state space, $u_\rho[k]$ is the control input, $(\omega_G[k+1] - \omega_G[k])$ is the system input, and the matrices $\mathbf{C}_1$ and $\mathbf{C}_2$ are algebraic expressions of the cost coefficients. The state space in this model is the vector of differences between each bus price and the market price at the slack bus, such that $x_{\rho i} = \rho_i - \rho_{sys}$.[2]

Given the dynamic equation, the next step is to define the control law. The control signal for updating each generator's reference frequency, based upon basic feedback control concepts, is proportional to the difference between the marginal cost of power at the given generator and the system or market price.

$$\mathbf{u}_\rho \equiv -\mathbf{K}_\rho \mathbf{x}_\rho \tag{9}$$

or

$$\mathbf{u}_\rho \equiv -\mathbf{K}_\rho (\rho_\mathrm{i} - \rho_\mathrm{sys}) \tag{10}$$

where $\mathbf{u}_\rho$ is the control signal to the generator's governor, ρ_i is the price for real power at generator i at the current production level, and for this analysis is assumed to equal marginal cost, ρ_sys is the price the system is willing to pay the distributed generators, and so represents the marginal revenue to these generators, and the constant of proportionality, $\mathbf{K}_\rho$, is the controller gain. The basic objective of the feedback control is to drive the system to an equilibrium state where $u_\rho \equiv 0$, implying that $\rho_i = \rho_{sys}$, or $MC_i = MR_i$ for all participating distributed generators.

Different methods for determining $\mathbf{K}_\rho$ have varying data requirements and different implications for the extent that control can be decentralized. A discussion of these tradeoffs is beyond the scope of this paper. What is interesting to note here is that alternative methods for determining $\mathbf{K}_\rho$ may have policy implications in that they tradeoff system performance with the expense of monitoring and data gathering (Cardell 1997).

Simulations demonstrating the use of the price signal in coordinating distribution system operation and control are presented below.

Simulations of Competitive Market Operation

Base Case -- Competitive Market

The first example refers back to Figures 8 and 9, as well as to the sample distribution system shown in Figure 1. Recall that the model input is a small load disturbance occurring at time t = 8 minutes. Conceptually the model action is that the market coordinator updates the system price in response to the disturbance, and then the distributed generators respond to this price change by altering their output such that the MC of generation equals the new MR (recall that the MR is defined as the market price since for now all the distributed generators are price takers).

[2] The values here, ρ_i and ρ_{sys}, both represent deviations from equilibrium, as is consistent with the use of linearized models. The variable ρ_{sys} is analogous to the $\Delta\rho$ value defined earlier as the deviation from the spot price offered by the system. Similarly, ρ_i can be interpreted as representing the deviation in the bid price at each distribution system bus.

Figure 8, without price feedback, shows the generator outputs and purchases from the grid increasing in response to the increase in demand, and the resultant price increase at each generator. Note that the slack bus represents power flow at the substation and so is a proxy for purchases from the grid. The price offered at this bus is ρ_{sys}, can be seen to change in response to the disturbance.

The two graphs in Figure 9 show the same system operating in a competitive market setting with the price signal implemented. The price signal is updated every ten minutes in this example. The proportion of the increased demand met by each generator is now determined by each the individual economic objective of operating where $MC = MR$, as well as by system needs to maintain power balance and the nominal system frequency. The lower right graph demonstrates that the relative prices are now much closer than they were without price feedback (upper right graph). These values are not identical though as a result of the competing need to maintain system frequency as well as account for the small system losses.

Non-Participation in Price Feedback

The simplest market structure simulated with the price model is the competitive market example above where all the small generators are incorporated into the price control loop. It is likely however, that while the system is in the process of being restructured some generators will elect to not respond to the price signal, instead remaining under direct central control. Figure 10 shows the output and corresponding prices in the test system when there are four combustion turbines installed, but only one has elected to participate in the price feedback framework. The solid line, lowest on the graph represents the system purchases and price, and the line just above the system (dot-dash line) represents the single combustion turbine (CT) that responds to the price signal.

The remaining three CTs have elected to not participate in the price feedback system, and as a result they do not reduce their output to match ρ_i to ρ_{sys}. An important point to note though is that this *does not* imply that they are now receiving the higher price corresponding to the level on the right-hand graph. The price they receive is determined exogenously by the central authority, and the right-hand graph shows the price *at the generators* of producing at the given level, but not the price they receive. The generators not participating are seen to produce at a level above the system marginal cost. This result can be interpreted as reflecting a suboptimal level of system efficiency and performance, due to the non-competitive decision making of three of the generators.

Imperfect Information: Uncertainty

The market organization itself is altered for the final category of market interactions. The first variation to the competitive market is a weakening of the assumption of perfect information. Imperfect information results both from uniform uncertainty in measurements and system values, and also from unequal access to system information. Unequal access can result from generators that were originally owned by a utility simply having greater operating experience than new, independent generators. It could also be the result of generators that contract to a power marketer, having access to more extensive, shared information than single units. In either case, one impact of such uncertainty in information will be that the independent generators will calculate their optimal control gain based on an estimated set of parameters, and will then operate in the actual distribution system. The estimated and actual values are likely to be different. Figure 11 shows the response of the system with one hydro and one

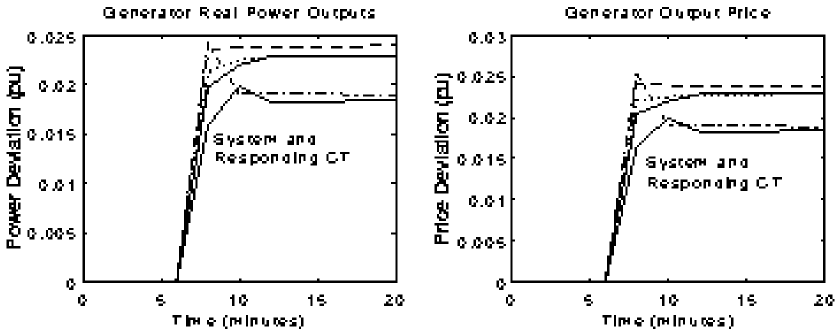

Figure 0: Generation and Price Deviations with Single CT Responding to Price Signal

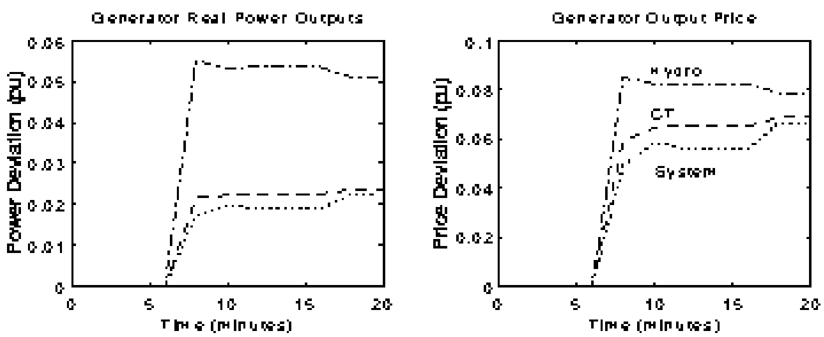

Figure 0: Price Signal Response with Imperfect Information

CT when their estimated parameter values differ from the actual values by 10% to 25%.

Figure 11 shows that the system remains stable even with this uncertainty. However, comparing this figure with Figure 9, when there is no uncertainty, reveals that the convergence of the output levels to the target equilibrium, as driven by the price signal, is much slower when there is uncertainty than when there is none.

Conclusions

It is possible that an increased penetration of small scale generators in the distribution system will adversely affect system stability and reliability unless new attention is paid to generator controls and their settings. As we demonstrated in this paper, an understanding of both the characteristics introduced by these small generators, and the differences between the distribution and transmission systems leads to an understanding of how system stability can be maintained. Identification of significant system characteristics suggested various methods for stabilizing the system, requiring that close attention be paid to generator selection (size or inertia), operating parameters and local control design (time constants and controller gains). It was also demonstrated, that in some cases instability may only occur as the number of distributed generators in the distribution system increases. A deregulated and competitive energy market incorporating distributed generators is more consistent with decentralized than with centralized operation and control strategies. The methods for stabilizing the system introduced in this paper do require some degree of centralized control or oversight in generator selection and operation.

The second major topic of this paper was the development of a price based control signal used to facilitate the coordination of distributed generators in a decentralized and competitive system. The price framework proposed here is strongly grounded in basic feedback control theory. It is assumed that the owners of the new, small generators will operate in the emerging competitive markets, independent of a central authority. These distributed generators will also required an incentive to supply ancillary services, or they would be likely to concentrate on the supply and demand market for real power. This paper demonstrated the use of a closed loop price signal which allows distributed generators to operate in a competitive market without depending upon the extensive information and centralized control structure of the traditional power system. This paper has also shown that if generators are to be sited in the distribution system in significant numbers, then operations and control issues that have historically been of concern only at the transmission level may become concerns for the distribution level as well. If this does occur, the standards and operating procedures may need to be developed in a coordinated fashion for the transmission and distribution systems.

Acknowledgments

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