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CONTROL STRUCTURES FOR COMPETITIVE, MARKET-DRIVEN POWER SYSTEMS

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ABSTRACT

Electric power networks are among the largest of human engineered systems, with dynamic performance coupled across circuits of continental scale. Effective feedback control is crtitical to achieve reliable provision electric power in these large scale systems. Given electricity's importance to modern industrial societies, and the range of practically important control challenges electric power systems present, they have been a prominent application for control analysis and design over the past century. Today, new questions are being introduced by the policy shift towards use of decentralized, competive market mechanisms for operation. This shift dictates examiniation of new control architectures, and opens the door to a number of interesting research issues in control system design, stability analysis, and dynamic games.

I. INTRODUCTION: THE CHANGING STRUCTURE OF ELECTRIC POWER SYSTEM OPERATION

The long history of control applications in electric power, and conservative engineering and control philosophies in a regulated industry have contributed to a perception that the key control problems of electric power systems have been thoroughly solved. To some degree, this perception *was* correct. When conservatively engineered and operated, the electromechanical dynamics of power networks can behave fairly linearly. In this context, local controllers based on classical linear control design philosophies proved reasonably effective at maintaining desirable dynamic performance characteristics, with centralized control exercised through period setpoint updates.

While the physical characteristics of the network and generation equipment contributed in part to a centralized, hierachical control structure, this structure was also very much dictated by the institutional structure of the organizations that operated power systems in the US and around the world. An elaboration of this argument may be found in [1]. Throughout most of the twentieth century, US electric utilities were regional regulated monopolies in which a single business entity was responsible for local equipment and its controllers, the centralized command of setpoints, and the network reconfiguration (e.g., switched capacitor banks, transmission line switching). In other parts of the world, where electric power networks were often operated as state owned entities, centralized network control and optimization was even tighter.

In the US, the electric power system is moving to an era in which its operation will be governed by a very different regulatory and institutional structure. The regional monopolies held by electric utility companies, with vertical integration encompassing ownership and control of local generation equipment up through the regional system operation centers, are being disassembled to allow for competitive provision of electric generation. Restructuring is coming about largely through legislative and associated regulatory actions, elements of which may be traced back to the Public Utility Regulatory Policies Act of 1978 (PURPA). Further steps towards a competitive structure came with the Energy Policy Act of 1992. This act laid the groundwork for the most direct impetus for change, in two landmark orders from the Federal Energy Regulatory Commission (FERC), numbers 888 and 889 [2], [3]. These 1996 rulings imposed a number of requirements with the goal of opening the US electric power system to competitive provision of generation. The FERC orders also made possible the most visible US experiment in competive electric markets, put in place by California Assembly Bill 1890, also passed in 1996. In the context of system control, perhaps the most critical element of the FERC rulings was the requirement for functional separation of generation activities from the central control of the transmission grid. Given the historically tight integration of these activities in the old vertically integrated utility model, this requirement indirectly mandated significant changes in the structure of control in the US power grid.

II. POWER SYSTEM DYNAMICS AND THE HISTORIC STRUCTURE OF GRID CONTROL

To understand the control issues in a synchronous ac power grid, there are several cornerstones. First, one must understand the control objectives that have traditionally been assumed to represent customer and societal needs. In addition, one must grasp the way in which dynamics of synchronous rotating generators contribute to grid-wide frequency regulation, the control actions available at each machine, and the control actions available at other devices that are elements of the network.

Control Objectives in Power Systems

At a basic level, the control objectives in a power grid follow from desirable operating characteristics that customers often take for granted. Whether or not this objective is consciously formulated, a residential customer desires that, at the connection point, the rest of the electric power network behaves like an ideal sinusoidal voltage source at 60 Hz, 120 volts rms magnitude. Clearly, the physical reality is much more complex; but in normal operation, US utilities often come very close to meeting this ideal. Hence, the simplified control objective is one of maintaining all generators very close to the target frequency of 60 Hz, and maintaining voltage magnitudes in the grid so that customers see nearly constant 120 volts rms, or the rated voltage magnitude appropriate to their consumption level. These represent control objectives on a relatively fast time scale, from tens of milliseconds out to minutes.

On a longer time scale, the other key customer desire is that electric power be economically delivered. To meet this objective, the traditional regulated utility operated on a cost minimizing philosophy. Construction and operation of generating plants was historically the dominant cost in electric power provision. Once plants are built, and paying off investment becomes a fixed cost, fuel costs become the dominant variable cost. The rate of fuel consumption, and hence cost of operation per hour, is a function of a generating plant's electrical power output level. To be able to meet peak load reliably, the total available capacity of generation must exceed the level of consumption at peak time periods; this implies that over most operating hours, there will be flexibility in the choice of electrical power output levels among various generating plants in a large network. Operating cost minimization then becomes a two stage optimization problem. Suppose that the set of generators available at an instant of time is known. One has the problem of determining the exact power output level for each generator that is locally feasible for the equipment, such that the sum of the power outputs meets total customer load plus transmission and distribution losses, while minimizing variable operating costs. At a higher level of optimization, one has the problem of determining which set of generators should be "on-line," ready to deliver power to the grid. The latter problem is formally "NP-hard" when treated with realistic modeling of intertemporal constraints and non-convex cost functions.

Hence, our original objective of controlling generators to economically maintain sinusoidal voltage frequency and magnitude takes on several additional facets. The historic solution to the problem in the US coupled local governor feedback, with a slower time scale regional feedback control, and ultimately with the open loop update of economically attractive target output levels. The regional feedback control is generally known by the acronym AGC (automatic generation control); for detail see [4], [5].

Grid Frequency Regulation

Consider the the control problem of regulating generators to achieve frequency control. The first observation is that an interconnected grid is truly in equilibrium only if all generators are at the same frequency, and that at such an equilibrium there must be a system-wide balance between generated power and load consumption plus losses. Any mismatch in power production relative to power consumption drives a change in speed (and hence instantaneous frequency) at one or more generators. Hence, for a system at equilibrium, or varying quasi-statically, frequency serves as a system-wide, "shared" signal that indicates the relative balance between total generation power and total consumption. In a synchronously connected grid, frequency decreases when total power consumption exceeds total production, and increases when production exceeds consumption. It is this inherent feature of the dynamics that allows electric power grids to maintain system-wide balance without instantaneous measurement and grid wide comunication of power consumption and production at all points.

To complete this overview of electromechanical dynamics, it is important to recognize that frequency dependence of power consumption in some loads, as well as damping effects at generators, create a positive, roughly linear correlation of power consumption to frequency deviation. This is a natural restorative effect that provides damping, and can allow the system to "find" a new equilibrium when there are minor variations in frequency independent components of load consumption. For example, if a frequency independent component of load consumption (which may be viewed as an exogenous input) were to increase slightly, and no control action were present to vary the mechanical power feeding generators, the system frequency would gradually decrease, until a new equilibrium was reached at which the decrease in frequency dependent load (and losses) balanced the original increase in the frequency independent load.

The natural damping effect of frequency dependent load is small, and long term system frequency variations would be unacceptably large if this were the only corrective mechanism. Therefore, as a first step toward frequency correction and power balance, there exists a local control loop that dictates incremental changes in mechanical power from the prime mover (e.g., turbine), based on local measurements of that machine's mechanical speed (proportional to its electrical frequency); this is typically termed the speed governor loop. It is important to recognize that the mechanical power command signal produced by the governor loop typically will not be the only signal contributing the prime mover power command. The governor loop operates with relatively broad bandwidth; other signals contributing to mechanical power command typically arise from slower control loops, or from periodically updated open loop setpoint commands. Governor feedback is typically dominated by a simple proportional term. The gain constant of the proportional feedback is inversely specified as normalized constant, the percentage "droop." Droop describes the percentage change in frequency that, acting through this proportional feedback, would yield a commanded change in mechanical power equal to the rated power of the generator. The dynamics of the loop are complicated by the fact that there is a nontrivial dynamic transfer characteristic for the prime mover, relating commanded change in mechanical power to actual mechanical power achieved at the shaft. Moreover, given the natural load damping effect described above, governor loops often have a small, intentional deadband. The design philosophy here is to allow the system to find a new equilibrium without any change in prime mover power outputs if the resulting deviation in steady state frequency is sufficiently small.

For the next higher level in the generation control hierarchy, it is useful to first consider a simple approach to system-wide frequency correction, recognizing that the proportional control of the local governor loops alone allows steady state frequency error, away from the desired 60 Hz setpoint. In this simple scheme, a single "master machine" has an integral control term with small gain, added to its governor control loop, so that this one machine controls to zero steady state frequency error. The nature of the interconnected dynamics then ensures that this equilibrium frequency is imposed on the whole interconnected area. However, while conceptually useful for illustration, this simple scheme is not practical for the large synchronous interconnections that exist in North America.

As the size of synchronous interconnected regions grew in the US, it became clear that assigning frequency control to a single master machine was infeasible. In the 1960's there developed in the US an approach toward automating system-wide frequency correction and power balance. While the term does not have a unique definition, the family of control techniques developed generally come under the title of "Automatic Generation Control," of AGC. Extending from the simple master machine concept, it is important to recognize that only a subset of generators in the system need to participate in AGC; i.e., only a subset of machines have supplementary signals added to the prime mover power command. These supplementary signals are not local, but rather are computed centrally, for a portion of the grid and a corresponding set of generators that lies within a defined "control area." Currently, there exist 136 control areas within the North American grid. These control areas are administratively defined by the North American Electric Reliability Council[1] (NERC). Physically, they represent disjoint subsets of the North American transmission grid, whose union covers (essentially) the entire grid. Moreover, transmission lines that connect between control areas, known as "tie-lines," are typically required to have measurement devices which allow monitoring of the flow of power on these lines. These tie lines are operated with agreed upon schedules that dictate the desired net power flow between any connected pair of control areas (an "interchange" schedule). The interchange schedules provide a setpoint for the measured output quantity of net flow of power on the tie lines between two areas. Regulating operation at or near these setpoint values becomes an added control objective for the AGC level of generator control.

The control objective for AGC (as administratively monitored by the North American Electric Reliability Council) becomes one of keeping the maximum excursion of the so-called ACE (Area Control Error) signal within specified bounds, and ensuring that it crosses through a zero value within a specified period. ACE is a weighted sum of the two quantities of frequency error and tie line flow error. Therefore, a zero value of the ACE signal does not precisely guarantee zero tie line error, nor zero frequency error. In practice, the quality of frequency regulation in North America is extraordinarily good (NERC publishes average frequency deviations on a monthly basis; typical values are less than ±0.003 Hz), so zero ACE signal does indicate that tie line flow deviations are very close to zero. Historically, the integral of tie line interchange errors (which indicate net energy deviation from scheduled exchange) were monitored, and an after the fact accounting done to settle the financial impact of this "inadvertent interchange" of energy between control areas. Not surprisingly, this financial use of the ACE construct is undergoing scrutiny and modification in the transition to a competitive environment.

The review of generation control above is necessarily somewhat superficial; the interested reader is strongly advised to seek more detailed accounts. However, the review and historical perspective above are intended to emphasize the significant institutional structure and history that underlies current control practice. The actual control algorithms are relatively simple, but the dynamics of the physical system they act upon, and the institutional arrangements that determine the control objectives and possibilities, are exceedingly complex.

III. MARKET BASED CONTROL ARCHITECTURES

Based on an understanding of the historic system structure described above, one can appreciate the natural approach that may be taken in exercising control over generation through market based mechanisms. Most of the current near real time markets relie upon a frequently updated auction to determine the power output of the generating units attached to the system. In order to formulate a number of related problem in a control context, we will take the liberty of idealizing such a periodically updated auction as a continuous process. In this context, we adopt what is roughly a Cournout model: there is a system wide price (which can be refined to allow for locational pricing in the grid). Producers and consumers respond through a decision process in which they choose their instantaneous power production or consumption based on local exogenous inputs, and this system (marginal) price information. The price setting mechanism should then seek to balance system wide supply and demand for power. From our earlier discussion, a reader should recall that the acceptable physical operation demands that in steady state, system wide power supply and power demand (with losses accounted for) must balance to zero. This suggests that one might naturally set price based on the integral of power imbalance; that is, that the price might best be set based on *energy imbalance*, as suggested in Figure 1 below. In this way, the selection of price setting mechanism can best be viewed as a feedback design problem. An additional observation, whose implication for a market environment dates back to the pioneering work of Fred Schweppe and his co-workers [9], is that system frequency becomes an easily measurable surrogate for energy imbalance. Therefore, one could imaging a realizable scheme that continuously sets set system price based on frequency error; proposals for such schemes generally come under the title of frequency reguation pricing, or ACE (Area Control Error) pricing.

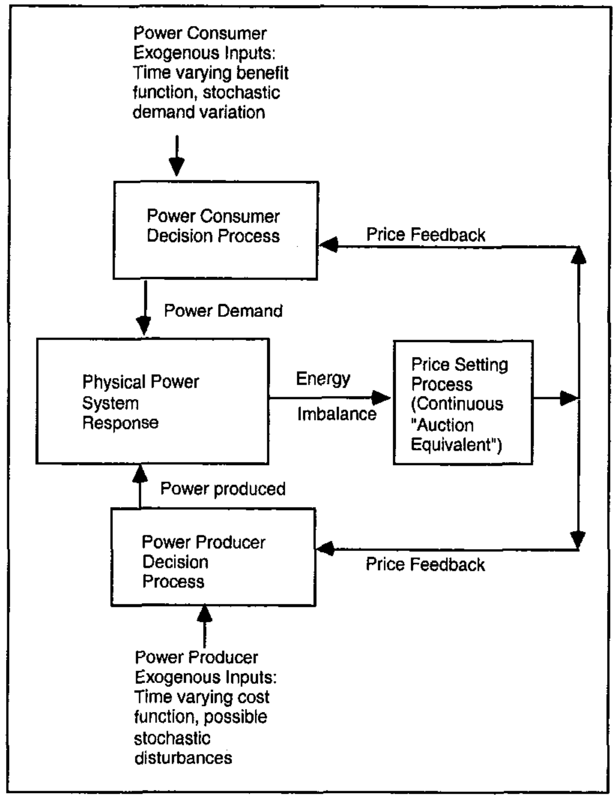

Figure 1: Market-Based Control Structure

Such a feedback control formulation raises a host of interesting research questions, many of which hold significant policy impact. First is the questions of stability and dynamic performance of such a system. There is a general impetus in power markets toward increasing the speed with which market prices are updated, with the idea that more precise tracking of price will yield greater economic efficiency. Yet clearly, as the time scale of market updates begins to approach the time scale of physical electromechanical dynamics, the

[1]For a wealth of information relating to the administration, operation, and historic performance of the North American power grid, as well as standards for its control, NERC maintains a very extensive set of resources on the internet at **www.nerc.com**.

potential for undesirable dynamic performance, and even instability, becomes a real issue in the feedback system created by prices. Moreover, the design of the decision algorithms for producers and consumers (such as bidding strategies for producers) becomes an interesting prooblem in dynamic games under uncertainty. In a competitive environment, a producer will seek to maximize profit over some time horizon (perhaps the finacial quarter), and over some portfolio of individual generator sets. If the generator were to naively view price as an exogenous quantity, then he or she likely behaves as a simple "economically rational" producer: when offered price exceeds the cost of production, increase output; when offered price is below price of production, decrease output. Such a simple model yields the social beneficial equilibrium in which system-wide marginal price equals the incremental cost of production. However, one need only consider the feedback loop of Figure 1 to recognize that this socially beneficial behavior is unlikely in practice, because the price is *not* independent of the production decisions.

Given that the power output of a group of generators will influence system price, it is natural for the generator owner to consider a nonlinear optimal control problem, in which production level is chosen to maximize the integral over time of the product of system price and power output; i.e., maximize profit. Given that the input/output relation of other producers and consumers is not precisely known to the producer in question, there exists an associated identification problem. If one further recognizes that other producers and consumers may strategically respond to the behavior of our profit maximizing producer, this further becomes a dynamic game. As indicated by the recent experience of late 2000 early 2001 in the California market, the financial stakes in such a game are extremely high.

IV. THE ROLE OF NEW INFORMATION AND MEASUREMENT TECHNOLOGIES

One of the questions in a restructured, competitive power network is the role of grid information. The FERC orders require that information regarding the power transfer capability of the grid be made widely available and auditable, to allow evaluation of potential for power transfers. In contrast to this, in a competitive market, individual generator owners will want to guard data regarding their production resources and production decision processes as proprietary information. Studies of dynamic performance characteristics of the power system, and associated control systems design, require both types of data: the transmission system parameters and configuration, and detailed dynamic characteristics of generating units. Who will possess both types of data? In the evolving institutional structure, it seems generally agreed that there must remain a central body overseeing the grid, usually termed the "Independent System Operator," or ISO. The California and the Pennsylvania-New Jersey-Maryland interconnection have well developed ISO's; slightly less mature ISOs appear essentially complete (as of early 2001) for New England and for New York. Notably, all but California are regions that had strong regional control centers coordinating the resources multiple utilities before the advent of orders 888 and 889; such multi-company regional control centers are not common to all regions of the US. Other regions of the US await agreements to form ISOs.

Based on the examples in place so far, the ISO is typically given strong administrative powers, and will likely be in a position to *collect* both types of data. This body is also likely to take responsibility for engineering analyses to ensure desirable dynamic performance. But even if the ISO has administrative power to collect proprietary generator dynamic data from individual owners, will it have the resources to validate this huge data set? As reported in [15], the dynamic study models in existence in the Western US (arguably among the most advanced in the world) had significant inaccuracies prior to the blackouts experienced in the summer of 1996. In particular, had the exact initiating events been studied in advance, simulation tools using the (then) best available data would have failed to correctly predict the occurrence of major blackouts. A major post-mortem engineering effort later corrected model parameters to a degree that the simulation tools did match actual occurrences with fidelity. We may naturally ask how much more severe this situation could become in the future, if we rely on traditional methods to gather data and assemble dynamic models.

In recent years, the global positioning satellite system (GPS) has provided a low cost means of acquiring precisely synchronized time references at remote measurement points. In the power system, this has created the opportunity to precisely and directly measure relative phase angles of geographically dispersed sinusoidal voltages in the grid; these are often termed "wide area" phasor measurements. This adds a very valuable measurement to the set available for (steady state) state estimation. It also creates opportunities for improved system protection and dynamic control (for a recent sampling of these ideas, see [18], [19]).

Control Opportunities in Flexible AC Transmission

New applications of high power electronics in the transmission grid are often grouped under the heading of "Flexible AC Transmission," or FACTS [20]. FACTS devices can make the transmission grid much more dynamically controllable, rather than leaving it to operate only as a passive circuit. In the eyes of many observers, FACTS technologies have been a potential revolution that has continued to wait in the wings for a number of years. While a number of interesting demonstration projects have been completed, or are on-going, significant penetration of this technology into the high voltage transmission grid has yet to occur. This delay is perhaps not surprising given the institutional restructuring of the US grid. FACTS devices are relatively high cost elements that will not contribute to economic power generation directly, but rather indirectly, through more efficient control and utilization of the transmission system. In the aftermath of FERC's 1996 orders, there remain open questions regarding means for recovery of investment in the transmission grid, as well as organizational questions about the form of Independent System Operators (or other entities) for some portions of the US. However, as issues relating to transmission investment are resolved, it is likely that the FACTS revolution will come, and with it, a range of interesting new control opportunities and challenges.

Power electronic controllers can present challenging nonlinear problems, because fundamentally, these devices are composed of circuits in which controlled switches are the primary regulating element. In transmission applications, one is typically attempting to control the 60 Hz fundamental component of a current or voltage waveform, or of an impedance, by switching within an appropriate circuit topology. When the switching frequency is significantly above that of the fundamental, as is the case in low power applications, averaging techniques provide a fairly tractable, usually linear, model for control design. However, present solid state technologies for high power are limited in their switching frequency by loss effects. The limitations on switching frequency create much more complex dynamic behavior and challenges to control design. Moreover, combinations of new circuit topologies and devices in the so-called "Universal Power Flow Controller" [21] create an opportunity for significantly enhancing steady state power flow in a manner that could make the economics of such FACTS technology much more attractive. Once this technology is deployed in the grid, it will also open the door to many interesting opportunities in control design for dynamic performance enhancement.

V. DIRECTIONS FOR POWER SYSTEMS CONTROL DEVELOPMENT AND RESEARCH

Perhaps the first key control challenge in the immediate future for power systems is one alluded to several times above; that of rethinking the existing hierarchical system of system-wide frequency control, the AGC system. This is as much a problem of administration as it is one of control design. Effective economic incentives must be found to encourage participation of competitive units in "global" frequency regulation. The NERC web site (see footnote 4) provides up to date documentation of the US perspective on the next generation of AGC. However, beyond the administrative and economic aspects, significant opportunities exist for conceptual innovation in the controller designs. In the overview of AGC provided in [7], the authors and various discussors allude disparagingly to attempts in the 1970's to apply optimal control design concepts to the frequency regulation. These optimal control based designs were critiqued as grossly unrealistic, neglecting the many practical constraints on equipment response rates and bounds, and issues of wear and tear on steam valve systems. However, recent work such as [8] has begun to re-examine the use of optimal control in frequency regulation in steam driven electric generators, bringing in much more realistic representations of the steam flow system and its constraints.

More broadly, the AGC problem encapsulates the general nature of challenges that will likely be recurring themes in control design as power systems move towards a competitive generation market. In particular, how does one migrate from a control structure predicated upon centralized ownership and unified administration of generation and transmission control equipment that existed in the past? As this paper's review attempted to indicate, generators are among the most effective elements for achieving system-wide control objectives of frequency regulation and stable dynamic response, and to a lesser degree, voltage control. Yet these "control resources" (generators) will be owned and administered by independent, profit maximizing entities, divorced from the Independent System Operators that have responsibility for the transmission. What new structures of control and what economic incentives will serve to align the individual profit maximizing objectives of generation owners with system-wide control objectives? To the extent that a central body, such as the Independent System Operator, will continue to tackle system-wide optimization, dynamic control design, and performance validation, the issue of NP-hard computational problems in power systems remains significant. Designing control systems that provide acceptable dynamic performance over wide ranging operating conditions and grid configurations is a recurring challenge, and a number of works have sought to transfer concepts from robust stability and controller design literature to power systems applications; see, for example, [24]. However, power systems have long been recognized as suffering from the "curse of dimensionality;" the developments of computational complexity allow one to formally classify many of the robust stability problems found in power systems to be NP-hard [25]. In the robust control literature, and in a range of control design problems, there has been a recent recognition of the power of probabilistic methods in treating NP-hard analysis and design problems [26]. Transfer of these concepts to power systems control design is an extremely appealing avenue for future work.

On the same theme of computationally challenging problems, another aspect of control design relevant to power applications is the potential for strong interaction between continuously acting feedback controllers, and discontinuous, discrete switching events, such as the action of protective relays. Given the huge computational challenge these problems present, traditional approaches in power systems have been rather ad hoc, with initial control design efforts largely ignoring protective relay action, with, at best, follow-up simulation efforts to test if relay thresholds are encountered in foreseeable fault and system disturbance scenarios. Clearly, this approach is severely limited by fact that only those disturbance events and grid configurations anticipated in the "contingency list" are studied for interaction. It is almost a folk theorem that major failures in complex engineering systems, such as power grids, result from the simultaneous occurrence of several rare events, or unusual operating conditions, the combination of which would not have been identified as a plausible subject for study a priori. Ideally, one would like a probabilistic, dynamic simulation, in which random actions occur periodically, so that the simulation may "unearth" unexpected interactions of discrete events and continuously acting controllers. However, in a system of large dimension, in which the events to be identified are extremely rare, direct computational implementation of this approach is completely intractable. With suitable modeling, the occurrence of the rare failure mode appears as a "large deviation" in state of the system. Similar issues appear in control and coordination of communication networks, in which one seeks to identify possible failure modes that have extremely low probability [27]. To improve computational tractability, the techniques of importance sampling have proven promising in the study of communication networks, and the control community is playing an active role in the continuing development of related methods. Such methods are beginning to see application in the study of power system protective relays [28]. Such methods could be critical to ensure reliability in the development of control and protection technology for the future US power grid.

Closely related to the issue treating interaction of discontinuous switching events and network reconfiguration, continuously acting feedback controls, and stochastically varying inputs, is the application of discrete event and hybrid systems concepts in the power systems context. Design methodologies to fully coordinate the consideration of the various types of phenomena in accurate models will be extremely challenging, but this mix of features is hardly unique to the power system application, and progress on general methods is being made [29]. Research into these topics is growing as competitive pressures demand less conservative operating margins in power networks.

Many of the topics for future development and research in power systems control represent new perspectives on long standing control problems, being motivated by restructuring and the emergence of competitive markets in the power industry. However, the study of competitive markets themselves, and certainly the interaction of physical dynamics with market driven events are important new topics for study within the power application. Power exchange prove a most interesting market for study, given the many time scales that are spanned by this market's activity, with strategic decisions to be made all the way from long term futures markets, down to second-by-second balancing of instantaneous generation and load. Work in [30] provides an overview of how this mix of market and control structures is achieved in the structure of the California Independent System Operator. As noted previously, there are a range of interesting questions with control aspects raised when market decisions by individual grid participants contribute as feedback elements to the overall dynamic behavior of the grid.

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