Managing Relationships Between Electric Power Industry Restructuring and Grid Reliability

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Introduction

Electric power in the U.S. is a more than $250-billion business, equivalent to slightly less than 5% of the U.S. Gross Domestic Product (see Figure 1). The electricity system is a critical infrastructure; its continued and reliable functioning is essential to the nation's economy and citizens' way of life. Electricity service is not the only critical networked infrastructure; water, communications, transportation are others.

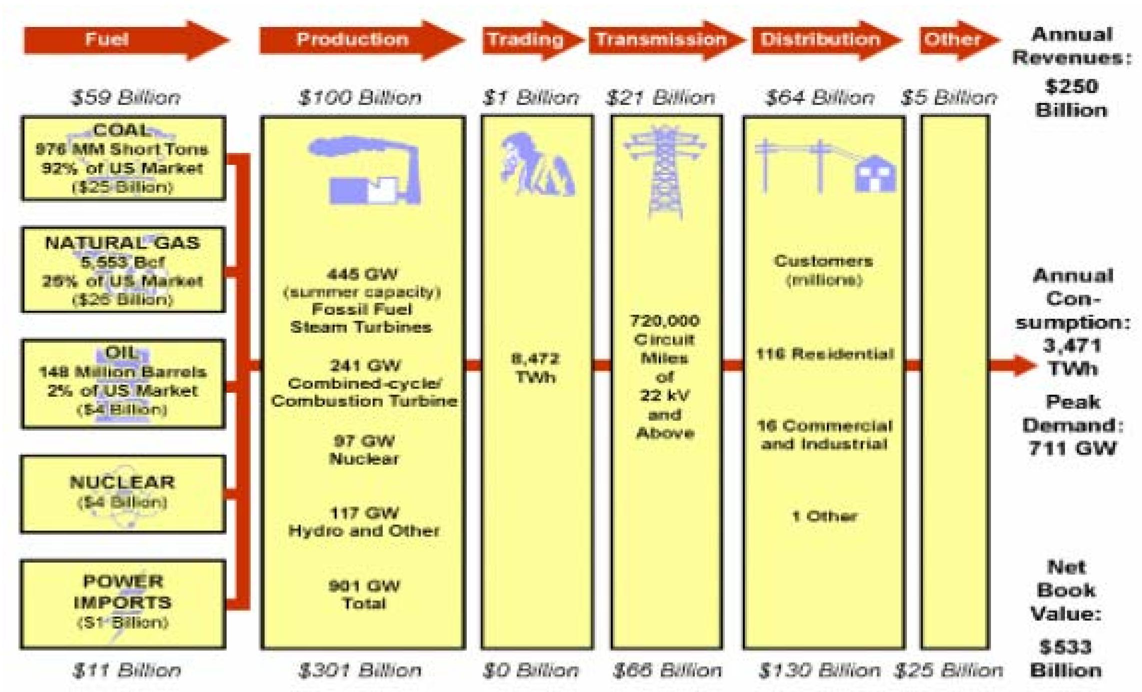

Figure 1: The U.S. electricity business value chain in 2002 (source: Cambridge Energy Research Associates)

The interconnection of the networks comprising the critical infrastructure is an ongoing evolutionary process, governed more by the "invisible hand" than any conscious act of design. As a result, the interdependency of these networks is not completely understood, nor are the resulting opportunities and vulnerabilities. As an example, in January 1991 a cut telecommunications fiber blocked 60 percent of the long-distance calls into and out of New York City (Neumann 1995). The subsequent disruption of voice and data traffic disabled air traffic control functions in New York; Washington, DC; and Boston. This single cut also disrupted trading operations at the New York Mercantile Exchange and several commodity exchanges. Later that same year, a farmer cut a fiber trunk while digging a hole in which to bury a cow. Four of the nation's twenty air traffic control centers were disrupted for hours.

The potential for overt acts against critical infrastructure is equally clear. The US Department of Defense conducted an exercise (Eligible Receiver) in which a "red team" demonstrated that the computer systems controlling the electric power grids are readily accessible to hackers. With readily available information and tools intruders could shut down large portions of the grid (Gertz 1998; Myers 1998). Most agree that electric power is the most critical infrastructure of all because, when it ceases to function, all others also eventually fail. It is therefore alarming to witness repeated reminders of the extent to which all of these networks are vulnerable to catastrophic failure. Because the various networks are interdependent, the vulnerability is particularly pronounced.

The U.S. is not the first in the world to undertake a restructuring of its electricity business. To refer to the undertaking as "deregulation" is a mistake; the term "restructuring" is more appropriate because, no matter what the industry's final structure is, some form of regulation will remain. The historical experience with deregulation of other industries has been reasonably successful from the point of view of economic efficiency (which is not the only metric by which we should judge success). For example, price decreases in the airline, natural gas, and long-distance telephone industries have been well documented (Winston 1993; Crandall and Ellig 1997). However, the electricity industry presents unprecedented complications for restructuring. In particular, electric power networks offer multiple simultaneous commodities, and there are a variety of externalities, such as reliability concerns, that imply that a pure market solution is unlikely to be efficient. In addition to the complications presented by the network itself, the unbundling of ancillary services suggests the existence of multi-dimensional markets where the sale of many related goods will take place. Although economists emphasize economic efficiency (i.e., cost savings) in market design, little is known about the efficiency properties of various auction designs for multiple commodities. And, when electricity industry restructuring began, virtually nothing was known about the effects of market design on the electricity system and its ability to sustain reliable operation for the public good in the face of these new designs (Toomey 2005).

The question we face as a result of the August 14, 2003 blackout is whether or not moving to a restructured environment must fundamentally degrade the reliability of the bulk system. That is, is the current direction of restructuring in basic conflict with operating a reliable system, or can we manage the rules so that it is not? The two major priorities for electric power are to operate a highly reliable system (ideally one that never fails) at a low cost (to cheap to meter). It seems obvious that a less reliable system costs less financially but may have huge social costs (the economy will be less efficient, deaths and looting can result from blackouts, etc.). The bottom line is that reliability costs money, and the questions are: what are consumers willing to pay for reliability, and how will payment be extracted from them? The vertically integrated utility model of the past produced a highly reliable system. Consumers reacted to energy costs quadrupling (even though costs did not quadruple in real dollars) during the 1970s, primarily because of a rise in fuel costs. It was assumed that economic and institutional arrangements could be restructured without affecting the reliability of the bulk electricity system.

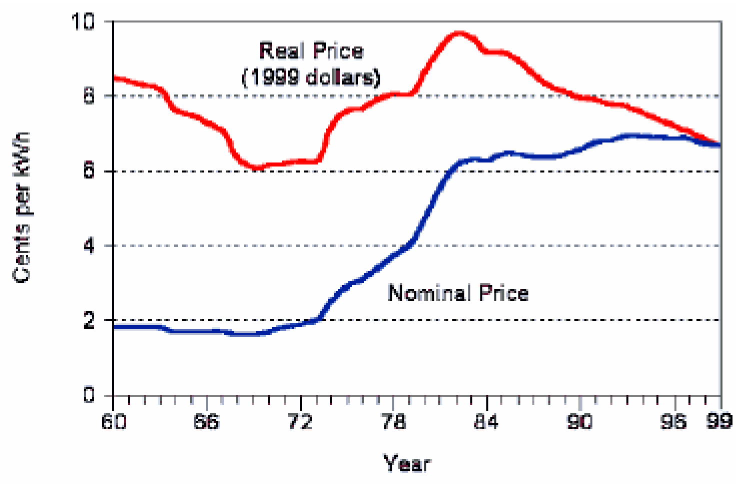

Figure 2: Average retail price of electricity sold by electric utilities from 1960-1999 (Source – U.S. Department of Energy, Energy Information Administration).

Restructuring and Reliability

Restructuring of the electric power industry in the U.S. is not about wires, transformers, substations, generating stations, or other apparatus. It is about inventing new institutional arrangements and driving technical innovation through economic incentives. The new institutional arrangements require new approaches to creation and management of information and the development of new management structures to support these new arrangements. According to "A century ago, electricity was the innovation; today it is the enabler of innovation. Electrification is not a historic event, rather it is an ongoing process, and today that process is being driven by computational speed and bandwidth, not motors and light bulbs. Underlying the dot-com revolution is electricity" (Schneider 2000). As we are in the midst of a transition from vertical integration to a restructured system, it is difficult to predict the end-game. However, restructuring probably means less markets and more regulation that initially thought. The approach taken in this paper is advocating a more structured and measured path through the transition rather than a prescription for what path we should be on.

Reliability in the electric power business has a technical meaning. Although it is possible to speak about the reliability of a particular system component, in this case we mean <u>system</u> reliability – the reliability of the interconnected power system. Any component can fail, but the system could continue to operate well because of, among other things, built-in redundancies and ability to reconfigure the system through control. During the August 14, 2003 blackout, it is fair to say that no device failed to operate as designed. It was the reliability policy in place at the time that primarily caused the system to cascade into failure.[1] This reliability policy is being re-thought as restructuring proceeds.

The North American Electric Reliability Council (NERC) definition of reliability divides the concept into two issues; *operational reliability*, also known as *security*, and *adequacy*. Oren explains the two issues as follows (Oren 2001):

Operational Reliability: "the ability of the system to withstand sudden disturbances." This element of reliability relates to short-term operations and is addressed by ancillary services, which include: voltage support, congestion relief, regulation (e.g., automatic generation control) capacity, spinning reserves, non-spinning reserves, replacement reserves.

Adequacy: "The ability of the system to supply the aggregate electric power and energy requirements of the consumers at all times." This element of reliability relates to planning and investment and is addressed by planning reserves, installed capacity, operable capacity, or available capacity.

In a recent NERC report entitled "2004 Long-Term Reliability Assessment" the section on "Transmission Issues" raises some concerns about the future adequacy of the transmission grid (NERC 2004). The report states:

> Over the past decade, the increased demands placed on the transmission system in response to industry restructuring and market-related needs are causing the grid to be operated closer to its reliability limits more of the time.
>
> The demand for electricity continued to grow in the 1980s and 1990s, but transmission additions have not kept pace. The uncertainty associated with transmission financing and cost recovery and the impediments to siting and building new transmission facilities have resulted in a general slow-down in construction of new transmission. In some areas of North America, increases in generating capability have surpassed the capability of the transmission system to simultaneously move all of the electricity capable of being produced. In addition, market-based electricity transactions flowing across the grid have increased, as has the incidence of grid congestion. The result is increased loading on existing transmission systems and tighter transmission operating margins.

This conclusion by NERC reflects the complicated state of the electric utility industry in North America at this point in time. Restructuring involves moving away from regional central planning to determine necessary generation and transmission investments to move toward decentralized decisions and reliance on market forces. In restructured markets, there is still a lot of uncertainty about the best way to replace the regulated system and provide the right incentives to maintain system adequacy and ensure that new generation and transmission are built.

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[1] The policy essentially says: "trust that your neighbor is pursuing a high standard of reliability and design your system accordingly. If there is any doubt that a piece of equipment would survive a contingency, remove during the contingency it so it will survive to operate another time."

Oren observes that "Security and Adequacy are clearly related since it is easier to keep a system secure when there is ample excess generation capacity." (Oren 2001). In a more recent article Oren notes that (Oren 2003):

> From an economic point of view security and adequacy are quite distinct in the sense that the former is a *public good* while the latter can potentially be treated as a *private good*. Security is a system wide phenomenon with inherent externality and free rider problems. For instance, it is not possible to exclude customers who refuse to pay for spinning reserves from enjoying the benefits of a secure system. Hence, like in the case of other public goods such as fire protection or military defense, security must be centrally managed and funded through some mandatory charges or self-provision rules…. Adequacy provision on the other hand…amounts to no more than insurance against shortages, which in a competitive environment with no barriers to entry translate into temporary price hikes. Such insurance can, at least in principle be treated as a private good by allowing customers to choose the level of protection they desire.

The assertion that at least some aspects of network quality are shared by all network users, and that each user's actions on the grid have "external" effects, is well accepted. The notion of private versus public goods is important. Economists believe efficient markets can be created for private goods while regulation is essential for the efficient use of a public good. If operational reliability (security) is a public good, the amount provided and the price paid for it should be regulated. And if reliability "trumps" economics, both planning and operations can be significantly affected. For example, when planning the system equipment may be needed to ensure a reliable supply that may not produce a direct economic payback. During operation, an operator may be required to procure expensive resources that may not be used in order to ensure an adequate reserve margin.[2]

Reasons to Restructure

The pros of restructuring are simple: most importantly, restructuring is supposed to lower the price of electricity for customers. The assumption has always been that reliability would be maintained. There is no evidence customer cost reduction has happened or is likely to happen in the U.S. In fact, [DC] examines the success in attaining that goal to date by using a variety of methods, from trend analysis to econometric analysis based on GARCH models. Customer rates are examined for four types of circumstances: regulated, deregulated, and publicly owned utilities, as well as restructured businesses. A variety of factors were controlled that might independently affect differences in electricity price: climate, fuel costs, and electricity generation by source. Taken as a whole, the preliminary results from the analysis do not support a conclusion that restructuring in the U.S. has, on average, led to lower electricity rates.

In contrast, (Kiesling 2004) reports that deregulation in the United Kingdom's has led to a 26-percent average price decrease and improved satisfaction with electricity service. Australia's structure, which makes states responsible for deregulation decisions, resembles the U.S.

[2] There are cases on record where an operator procured one megawatt of reserves at $10,000/MWh in order to satisfy a reliability requirement.

structure more than it does the UK's centralized government effort. Since 1991, Australia's customers have experienced an average price decrease of 24 percent.

In addition to eliciting price decreases, restructuring is intended to allow power to be sent from elsewhere to areas in which generation fuels are limited. Because the technology exists to send power generated in one area to customers located in a different region, restructuring should give customers the opportunity to "shop around" and buy electricity at the lowest price.

However, all of the effects of restructuring are not positive. Restructuring requires companies to cut costs, which has, in some cases, meant that reliable power is not available during times of peak demand. Until recently, many community-based programs, were partially funded by local power providers. Since restructuring, the funds for many of these programs have disappeared. Also, local power providers currently contribute large sums of money to the local tax base. As a result of restructuring, power may be supplied by companies located outside of the community who pay taxes elsewhere. As a result, local tax revenue may decrease. Some believe that restructuring has opened the door to market manipulation. This is because much of the present restructuring legislature requires companies to divest their generation capacity, which has resulted in new holding companies that only generate power. Currently, the 10 largest power companies in the U.S. generate nearly 50% of the power used. This type of market domination could lead to the same problem that initially started federal regulation of the electric power industry in the U.S. and the passage of the Public Utility Holding Company Act (PUHCA) in 1935 and the passage of the Federal Powers Act and formation of the Federal Power Commission in 1936. The Energy Policy Act repealed PUHCA but retained some of its provisions[3].

Organizational Complexities

In April, 1996 the Federal Energy Regulatory Commission (FERC) issued the final version of Order 888 requiring electricity utilities to open their transmission lines to competitors on a nondiscriminatory basis. In response to this order, electricity companies began to cut staff and merge their organizations.

According to (Whitehead 2003):

> For decades, there was stability and simplicity in the electric utility business with few and minor changes. Each utility knew what their responsibilities were and clearly knew that their prime responsibility was to keep the lights on in their service areas. Today, there are a number of different electrical service business models in existence, many involving several companies each with different and separate responsibilities in serving a particular region. These require additional reliance on communications, coordination of technical functionality, and greater focus on the reliability needs of their electric customers.

[3] The Public Utility Holding Company Act of 1935 ("PUHCA") was repealed but the Energy Policy Act included consumer protection provisions by allowing FERC and State Commissions to review the books and records of public utility holding companies.

> Recent changes in the utility market include separating the functions of generation and transmission planning, emphasis on market focused developments, and encouragement of the formation of Regional Transmission Organizations (RTO's) and Independent System Operators] (ISO's). But these developments have not been the only source of change. Another major contributor is the rapid changes in companies caused by acquisitions, mergers, and creation of separate sub-companies to, among other things, develop electric facilities in other parts of the country or the world. The recent rate of change has been far more rapid than any other time in the electric power industry. Maintaining high levels of reliability in this new, complex, and continually changing environment is a difficult challenge.

Whitehead astutely observes that companies have not only reorganized and merged but in the process added layers of complexity to the decision-making process. Quoting again from the report:

> Business instability and complexity creates an environment where breakdowns in communications occur, where confusion exists as to business responsibilities, and where a lack of focus exists on what was the prime mission of the companies – to keep the lights on. The lack of focus increases the opportunity for bad decisions in transmission or generation capital project budgeting and maintenance budgeting leading to an inadequate transmission system, failures of transmission, communications, or control equipment, and inadequate right of way maintenance.

Table 1 gives examples of multi-company layers with multiple responsibilities. New England can be described as being two layers deep, with an ISO layer and an individual utility layer. The First Energy business environment at the time of the August 14, 2003 blackout could be described as five layers composed of seven individual entities: American Transmission Systems (ATSI), which owns some of the transmission facilities; three other transmission operators, the Pennsylvania-New Jersey-Maryland Interconnection (PJM), which is the control area operator for the eastern part of the First Energy system; the Midwest Independent System Operator (MISO), which is the security coordinator and, with PJM, the control area operator; GridAmerica which shares ISO responsibilities with the MISO, and finally First Energy itself.

Table 1 – Table of company layers from – (Whitehead 2003)

COMPANY	TRANSMISSION OPERATOR(S) (TOs)	RTO or ISO	CONTROL AREA OPERATOR	RELIABILITY or SECURITY COORDINATOR
AEP	5 TOs	AEP	AEP	PJM
First Energy	ATSI and 3 Other TOs	MISO & GridAmerica	FE/PJM	MISO
IMO	Hydro One	IMO	IMO	IMO
ISO New England	17 TOs	ISO New England	ISO New England	ISO New England
ITC	Detroit Edison	ITC	MECS	MISO

METC	Consumers Energy	METC	MECS	MISO
New York ISO	8 TOs	New York ISO	New York ISO	New York ISO
PJM	12 TOs	PJM	PJM	PJM

As a result of this type of complexity, lines of responsibility are often unclear, and accountability difficult to assign. This can mean that reliability solutions that are in conflict (e.g., uneconomical resources are needed from an entity that will not benefit in the reliability they produce for others) may not be resolved correctly.

Planning

The function of an electricity supply system is to maintain voltage waveforms of appropriate quality at the points of connection of end-use equipment (loads) and thus provide a continuous flow of electrical energy to meet end users' requirements. The transmission network is a shared resource in an electricity industry that makes an essential contribution to this capability by:

- Providing connectivity among all large generators and all load centers and thus compensating for differences between the geographical distributions of generation and electricity demand;

- Improving supply availability by automatically exploiting the diversity between the stochastic processes of generator availability and electricity demand; and

- Improving supply quality by contributing to the management of voltage magnitude, phase balance and waveform purity, particularly when contingencies occur.

Regulated utilities engaged in planning processes to demonstrate due diligence with respect to their "obligation to serve" load. The planning process usually produced several plans for expansion of either generation, transmission or both. Transmission planning is the process of designing future network configurations to meet predicted future needs. It is an inherently cooperative process because the transmission network is a resource shared by all network users (generators and loads). Most regulated utilities were vertically integrated monopolies that were responsible for all generation, transmission, and distribution in one or more contiguous regions. These utilities could make central planning decisions for their service territories. In the U.S., there was additional coordination provided by power pools, federal and state regulators, and industry oversight organizations, such as NERC. An acceptable plan for expanding transmission carried with it an obligation for regulators to permit the utilities to earn an allowed rate on and return of all capital costs that were "used and useful." Under this form of regulation, it was possible to maintain transmission and generation adequacy, and, some would argue, the supply system was "over-built."

A regulated utility was obligated to meet all reasonable requests by end users for future supply needs, usually with little expectation that end users would provide advance notice of either the timing or location of their requirements. In return for accepting this broad obligation, the regulated utility was left with considerable planning autonomy and discretion to exercise engineering judgement in designing and implementing a supply-side solution. When the load doubled every 10 years, as it did up until the 1970s, network planning was usually subordinated to generation planning. In addition, there were relatively few public constraints on acquiring easements for new transmission. After the oil embargo in 1973, however, there was more public opposition to expansion when load growth slowed down and the capital costs of nuclear power plants escalated (Nelson and Peck 1985). However, the basic responsibilities for providing a reliable supply system did not change substantially.

Since restructuring of the U.S. electricity industry began during the 1990s, the planning process has become more complicated (Thomas et. al. 2005). A major reason is that many investment decisions, particularly for generators, are now determined by market forces rather than by a centralized decision process. The financial risk of investment falls on the investors and is no longer backed by the customers as it was under regulation. Consequently, there is no guarantee that market forces will meet all legitimate investment needs, even for maintaining generation adequacy. Although the financing of most transmission is still regulated, it is no longer clear how to assign the financial responsibilities for serving load, particularly for maintaining the reliability of supply. For example, there has been a substantial increase in the quantity of power transferred over long distances through the Tennessee Valley Authority (TVA) territory (see, for example, Figures 1 and 2). Both thermal and voltage constraints on transmission have been experienced in locations that were previously rarely congested.

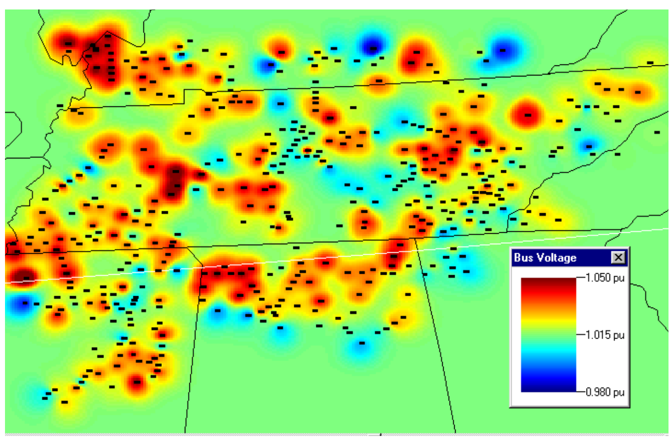

Figure 1. Normal peak-load voltage profile on the TVA system (July 1999)

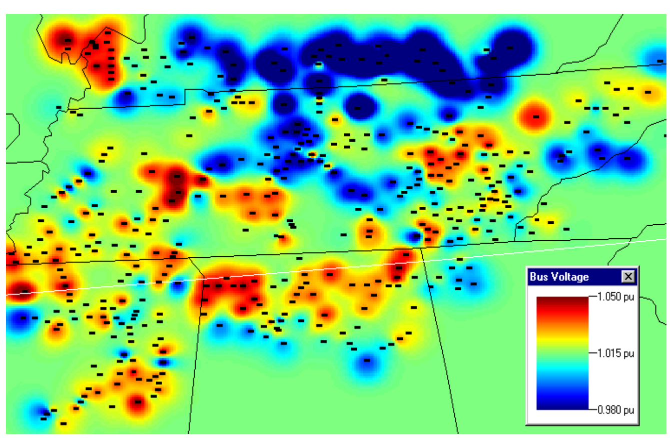

Figure 2. The voltage profile with 8,000 megawatts (MW) of loop flow (August 1999)

One solution to the problem of congestion caused by power transfers is to expand the capacity of the transmission network. However, it is not a simple task to divide the cost of this expansion between customers in the service territory and the many generators and loads in other service territories that benefit from the power transfers. When commercial power transfers through a network contribute to congestion, it is difficult for an individual transmission owner to predict how market forces will affect future congestion (possibly in new locations) on an expanded network. Because the transfers generally depend on decisions made in other service territories, will the transfers continue in the future, or do they represent a short-term arbitrage opportunity caused by temporary regional differences in fuel prices?

Finally, even if the transfers are temporary and transmission expansion is not required, it is still difficult to allocate the true system costs of transfers to individual transactions. Congestion resulting from transfers may result in higher nodal prices within a service territory, but there is no guarantee that the revenue collected for transfers from wheeling charges, for example, will end up compensating customers for the higher energy prices. Because there is no global optimization of the dispatch in the Eastern or the Western Interconnections, the financial payouts for some transfers may reflect anomalies because of price inconsistencies across the "seams" between control areas rather than true reductions in the cost of meeting load. In other words, completing a transaction that is commercially viable under current conditions does not guarantee that there will be positive net benefits to the system.

In addition to the new challenges associated with restructuring, the current structure of the U.S. utility industry is inherently complicated because of different combinations of public and private ownership, state and federal regulation, and merchant and regulated companies. This complicated structure suggests that the path to restructuring should be cautious. In particular, the reliability of supply is a shared responsibility for all users of a transmission network. It is important to determine what markets can and cannot do, particularly for the transmission network, if high standards of reliability are to be maintained in the future.

The Need for Design Standards in Power Grid Control Centers

The term "situational awareness" has emerged as part of the new vocabulary of the electric power business. Its meaning is clear: the correct and appropriate information must be available at the right time and place for operators to understand the current (and perhaps future) state of the system and the consequences of planned contingencies. We would like it to mean more. We really want a robust and reliable system in the presence of any uncertainties, technical or economic. We are far from that goal. Situational awareness requires "visibility." By a visible system we mean one where potentially dangerous situations are not hidden from an operator because they lack the means to observe it. And the old design concept of assessment and avoidance must be (and is being) displaced by command and control, which requires a heavy reliance on information systems.

The North American power grid is currently monitored and controlled by a very large number of control centers. In the era of vertically integrated utilities, each company had its own control center that was responsible for the portion of the grid in that geographical area. This concept of the "control area" has survived industry restructuring, and a control center in each control area is responsible for the generation-demand balance and reliable operation within that area. Even after some recent consolidation of control areas, the Eastern Interconnection in North America has more than 100 area control centers that monitor and control portions of the interconnection. However, there is little standardization among these control centers, and, even though they are monitoring one tightly interconnected synchronously operating power system, their data-gathering intervals, monitoring and alarming processes, supervisory control procedures, analytical tools for assessing contingencies, graphical user interfaces, etc. are all very different.

In recent years, another small set of second-level control centers, i.e., designated security coordinators, have been created to oversee and coordinate the reliability of a large geographical region which, like MISO, may encompass several area control centers. Unfortunately, these are so new that even best practices have not yet surfaced let alone standards. In fact, these second-level control centers often have a mixture of reliability and market functions, which further confuses their missions and processes.

Among the obvious lessons learned from the August 14, 2003 blackout is the need for knowledge about what is going on in the interconnection beyond one's own portion of the grid. It is also clear that the present operational procedures of calling up a neighboring control center to find out what is going on are not adequate, and continuous and automated methods of being able to observe what is going on in the rest of the interconnection, especially in the near neighborhood, are essential.

The difficulty of collecting data from the different control centers after the blackout and then processing it to determine what happened was a direct result of a lack of standardization. Making the problem more difficult is the fact that the communication system that moves the data from substations and generating stations to (and between) control centers was designed in the 1960s and is outmoded and inadequate to the challenges of moving large numbers of data quickly to where they are needed. In fact, the data collected by a modern substation automation system often cannot be channeled to the control center because of communication limitations. In addition, the information-processing capabilities of the control center computers have not been significantly enhanced even though computing power is relatively inexpensive these days. Thus, moving to better communication and computation technologies that support these control centers will improve coordination among control centers.

Although power system information needs are individually similar to the needs of other information users (e.g., the military, air traffic control, etc.), the complexity and variance in the electricity system's information types and needs are uncommon. The electric power business desperately needs new tools to create relevant information that can more accurately assess current state and predict outcomes in the face of uncertain events. An integrated set of communication protocols and protocol architectures is needed that will permit new information to flow easily and flexibly through different nodes on its way from source to user. Tools are also needed to help make difficult decisions that can have profound effects on the economy and reliability of the power system and the value of that system to its service providers and users. For example, a reliable and accurate security constrained optimal power flow software program would provide accurate pricing of real and reactive power under credible contingency planning. To date, most locational real power prices are determined by a linear program while the dispatch is provided by an optimal power flow program. Contingency evaluation is done after the fact. While this process will provide a secure system, it is not necessarily the most secure and economical dispatch of resources.

Research and Development (R&D)

R&D, particularly long-range work, has suffered during the formation of a competitive industry. For the utility industry today, R&D is a back-burner issue. Issues like stranded cost recovery and mergers appear to be more important. Utilities are spending their limited R&D funds to reduce operations and maintenance (O&M) costs or to improve reliability, for the most part using existing technology. There is little incentive to invest in advanced power generation, power delivery, storage, and communication or control technologies. The need for R&D as expressed by, for example Torpey in 1998 and others have not been realized (Torpey et. al 1998).

Utilities also have little incentive to invest in collaborative R&D projects, particularly if these projects would help their competitors. The Electric Power Research Institute and the Gas Research Institute have seen this dynamic play out in real time as they lose more and more supporting members. Utilities also have limited incentive to cost-share in government R&D projects. This is a difficult trend for the government to address. Congress is demanding that the government shift its R&D projects toward longer-term research, yet Congress is defining success as increased levels of industry cost sharing.

As Boston points out "Blackouts – small or large – are nothing new, but the reasons for some of the recent blackouts and near misses are disturbing. For example, the U.S. Department of Energy (DOE) cited Chicago's Commonwealth Edison for scrimping on its substation maintenance budget, which went from a high of $47 million in 1991 to just $15 million in 1998, as the company shifted money into its nuclear program and preparations for competition. Several systems were threatened when certain operators were unable to predict the massive amounts of power flowing across their systems from eager new sellers on one side to eager new buyers on the other." (Boston 2000).

The following material on R&D was taken from the excellent article by Thomas R. Schneider (Schneider 2000). I could find no way to say it better.

> The well-documented decline in U.S. energy R&D and the resulting underinvestment need to be a focus of current policy debates. While investments have declined on a global basis, energy R&D has fallen even further in the United States than in other industrialized nations and in real dollars, in spite of the continued importance of energy infrastructure to the economy, national security, and the environment. (See Table 1.)

Table 1: Decline in support of energy R&D

Select International Energy Agency Country	Decline in Energy R&D 1980-19952
Japan	+20%
France	- 6%
Canada	-33%
Italy	-53%
USA	-58%
Germany	-85%
UK	-89%

Yet the situation is even worse than these large-percent reductions suggest. Since 1973, an important component of U.S. energy R&D has been the voluntary public-benefit R&D of the electric utility industry through the collective mechanism of EPRI, formerly known as the Electric Power Research Institute. EPRI was the world leader in managing and implementing electricity research for the public benefit, sponsoring the lion's share of the electric utility R&D in the United States. EPRI expenditures on R&D are roughly two-thirds of total research expenditures by all the electric utility industries. In the early 1990s, total EPRI expenditures were nearly as great as the electricity-related R&D expenditures."

There is an obvious problem with both the amount being spent on R&D and what it is being spent on. Leadership is needed on an industry-wide basis to ensure all dimensions of R&D needed are marching in lockstep and in the right direction if restructuring is to be successful and system reliability is to be maintained or enhanced.

The Looming Manpower Crisis

Power engineering is among the oldest branches of electrical engineering, and the field is deemed to be mature. The power industry employs engineers from all disciplines (mechanical, electrical, civil, operations research, etc.) The availability of jobs and research funding in newer fields such as bioengineering, microelectronics, nanotechnology, and computers has steadily eroded interest in power engineering. The power industry employs about 5% of the nation's engineering force, yet it spends less on research than almost any other industry (see Figure 6).

The extensive reduction in engineering personnel at utilities has given the field a certain black eye in that job security, a long an industry standard and a reason to accept lower salaries, has been eliminated. The salary range offered by the power industry is typically below that of emerging industries (Gross et. al. 2004)

In addition, the average age of utility craft workers is 50, the highest average age of any industry in the U.S. More than 50% or about 200,000 current utility workers will retire by the year 2010, and 27.7% of all boilermakers in the U.S. are 50 years of age or older. In contrast, the average age of construction workers 37. The electricity industry's engineering workforce is aging, and engineering work is increasingly being outsourced.

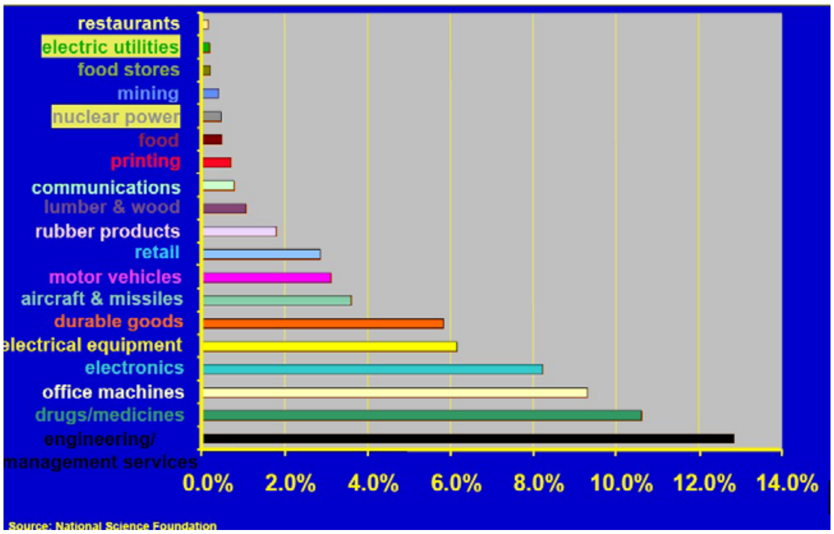

Figure 6: Research funding expenditures by industry (Source: National Science Foundation)

The power industry is regarded as mature, which is a euphemism for old and uninteresting. The restructuring of the power industry has resulted in a decrease in industry support for university power engineering programs and research despite the critical nature of the industry's infrastructure and the technical innovation that restructuring is meant to foster.

The intensive reduction in engineering personnel at utilities has sent a signal to students that there are no jobs in the industry. And when there are jobs available, salaries are typically below that of other emerging industries. As a result the undergraduate student enrollment in power systems engineering programs in the U.S. has been diminishing for many years. Graduate student enrollment has been steadier because of the large percentage of foreign students in the M.S. and Ph.D. programs.

There is a graying of the power engineering faculty in the U.S., with the average age of the professoriate creeping upward and the number of useful years remaining in their professional lives rapidly decreasing. The number of faculty retirements typically outpaces the number of additions. (Heydt and Vittal 2003)

One positive outcome of restructuring and some of the crises that have followed is a recent increase in interest among students. Restructuring and the California crisis have sharpened public interest in electricity, and the September 11, 2001 tragedy brought attention to issue the security of the power system and other critical infrastructure. The August 14, 2003 blackout evoked a renewed student interest in grid reliability, and enrollments in power courses have been up for the past couple of years.

Recommendations

The preceding sections were intended to lay out a broad picture of the current state of the U.S. electricity industry. Like all engineered systems, it needs constant attention to ensure that it is reliable, safe, and economically efficient. Some elements need immediate attention. The list of recommendations below is not intended to be exhaustive but rather a short list of what the author believes to be the most significant immediate challenges. These are obviously tainted by the authors' background and interests, but a balanced picture should emerge when aggregated with the recommendations of others in the group,

1. Ensure that the Transmission System is Up to the Job of Supporting a Market Structure.

The current U.S. transmission infrastructure is a legacy system. It relies on old technology, which raises questions about its long-term reliability. This system was designed to serve a fixed pattern of generation and load. It was designed and operated for reliability (minimize outages while protecting equipment) and economy (everyone shares in the benefits of operating least cost generation). Now its main use is to support markets where generator incentive is to maximize profit and the demand-side incentive is to minimize cost. The currently large volume of transactions along with low reserve margins is stressing grid operations. System constraints are affecting use and care of the grid. Deregulation uncertainty is contributing to reduced system expansions and upgrades (NERC projects that only a 5% increase i.e., 10,275 miles, in 230 kilovolt and higher lines are planned through 2013).

The transmission grid plays a pivotal role in the operation of electricity markets (transmission congestion segments markets and provides market-power opportunities). New networks cannot be designed well if we do not know the characteristics of the new markets. Although it is unlikely that a "one-size-fits-all" structure is the best solution for restructured markets, it is clear that transmission decisions require more coordination than generation decisions do. (It is unfortunate that FERC efforts to lay the foundation for a Standard Market Design coincided with the "energy crisis" in California and the corresponding increase in doubt about the potential benefits of deregulation). The transmission system plays dual roles in maintaining reliability and enabling inter-regional transfers of real energy. R&D is needed to ensure future transmission systems are compatible with new restructured system designs so that economic efficiency can be reliably achieved.

2. Build a National Reliability Center (NRC).

The creation of a National Reliability Center is consistent with the idea that reliability rather than economics should be the focus of grid operations. This idea was proposed by Overholt and Thomas after the August 2003 blackout (Overholt and Thomas 2003). The center is needed to significantly improve system reliability and enforce compliance with imminent grid reliability standards to prevent, to the extent possible, the recurrence of massive blackouts. The NRC's mission should be centered on development of procedures, plans, and tools for standard control room design, grid and market-monitoring capabilities, algorithms for analysis, real-time communication protocols, data collection, protection and dissemination, and other essentials to ensure complete real-time visibility and reliability services for the grid. These functions are not currently carried out by NERC nor is it likely that they will be carried out by the future Electric Reliability Organization (ERO) that will be formed as a result of passage of the Energy Policy

Act of 2005[4]. The NRC mission would be complementary to the functions of NERC or its successor, the ERO. We describe its design and function next.

Currently, transmission operators are unaware of many events that affect their operations because of the inability in many control centers to exchange real-time operating information (which, in turn, results from lack of standard procedures and protocols for this exchange). The NRC would be designed with communication and data collection protocols and procedures to assemble relevant data from across the interconnection to serve a series of functions as described below. A common communication layer would be developed based on a standard design for which tools for sensing data, creating and visualizing information, and exercising control functions can be built. This involves creation of an integrated set of communication protocols and architectures that permit new types of information to flow easily and flexibly. The NRC would need such this communication layer to receive data and produce information vital to system reliability.

Enforcing reliability standards will compel all system operators to adhere to defined voltage, frequency, reactive and real power, and other metrics to avoid penalties. Visualization tools for displaying several of these metrics have already been developed, and the Area Control Error (ACE)/frequency visualization system is now deployed nationwide. A series of tools to monitor and display voltage, load flows, generator performance, market performance, and security are under development. Prototype tools are also being developed and deployed for the collection and use of real-time, wide-area, synchronized data for system control and analysis. This wide-area system would function as the fundamental monitoring and visualization tool to detect and mitigate impending disturbances. The NRC is needed to fully take advantage of these and other tools. A series of basic monitoring and visualization systems for reliability standards compliance needs to be developed.

Transmission system operators perform security and contingency analyses using in-house programs that are not consistent or even compatible across boundaries. In addition, operators do not have access to or visual representation of expected status and contingency analyses of neighboring systems that influence daily operational planning. The NRC, with its interconnection-wide visibility, could perform the analysis and disseminate the information required for operators to view the status of their systems and those around them in near real-time. This center would maintain state-of-the-art state-estimator and contingency-analysis programs that run on sophisticated computing systems and provide these services on request to the entities responsible for initiating local reliability monitoring and control functions.

A central NRC in cooperation with industry partners could develop, evaluate, and maintain advanced tools to perform on-line assessment of grid reliability and security, and off-line, detailed studies for power-system planning, operations, and expansion over the entire

[4] The Energy Policy Act authorizes FERC to certify a single ERO and provides FERC with jurisdiction over all users, owners, and operators of the bulk power system for purposes of enforcing reliability standards. Both the ERO and FERC are granted the authority to impose penalties for violations of reliability standards. It does not specify, however, how and what information is gathered and how it is to be used to make these decisions. The choices are to require industry to provide the information or to create a body, like the NRC, charged with that obligation.

interconnection. Research and development on integrated security analysis tools, fast load-flow programs, and methods to supply them with real-time data are needed.

It is likely that standard control room designs, procedures, hardware, and software will evolve now that the requirement for mandatory grid reliability standards is in place with the passage of the Energy Policy Act. With allowances for regional variations, the NRC would be a central location to assist in maintaining this standardization, educate operators on the capabilities and use of the information supplied by the NRC's analysis services, and train operators through detailed simulations tailored to their regions.

3. Solve the Looming Manpower Crisis in Industry and Universities.

A more active role is needed for both federal and state government in direct support of power engineering research and education, given the critical role of continued government involvement in regulation of the industry. Continued restructuring of power engineering curricula is needed to strike an effective balance between making the discipline attractive to undergraduates and imparting solid engineering skills and basic foundations to its graduates. The current upsurge in student interest should be embraced to ensure that this upward trend is sustained. The best way to do this would be to support a multi-university - industry Center of Excellence focused on the nation's electric power problems. Section 925 of the Energy Policy Act of 2005 part (f) states

> The Secretary shall establish a research, development, and demonstration initiative specifically focused on tools needed to plan, operate, and expand the transmission and distribution grids in the presence of competitive market mechanisms for energy, load demand, customer response, and ancillary services.

Requirements such as this should be taken seriously and the opportunity used to re-establish power engineering programs in major universities.

4. Test Market Designs Before Deploying Them.

In the past, new markets were designed principally by economists based on their understanding of how other markets worked. There was little understanding of the effects in the electricity industry of externalities such as the network and ancillary services needed to support the transport of power.

An example is the handling of the signs of trouble in California electricity market in the summer of 2000. FERC Chairman James Hoecker was quoted as saying, "Never has the Commission had to address such a dramatic market meltdown as occurred in California's electricity market this summer. Never have residential customers been exposed to economic risk and financial hardship as they were in San Diego" (FERC 2000). As a result, FERC proposed major modifications to the structure of the wholesale market for power (FERC Order, 11/1/00). One of the proposals was to implement a soft cap on market prices at $150 per megawatt hour (MWh). This was a radical modification to the structure of the auction used to determine spot prices for electricity in the wholesale market. The new auction proposed by FERC was implemented in January, 2001.

These markets were not tested in an "experimental economic" environment before being deployed[5], and the soft-cap market did not work well. By experimental economics we mean the application of accepted laboratory methods to test the validity of economic theories and to exercise proposed market mechanisms. Nobel prize winner Vernon Smith sums it up as "Using cash-motivated students, economic experiments create real-world incentives to help us better understand why markets and other exchange systems work the way they do."

Spot prices for electricity in California remained consistently around $300/MWh from January to April, 2001, or roughly 10 times higher than in the previous year. Because the soft-cap market did not bring spot prices down to competitive levels, a new FERC Order (April 26, 2001) proposed to "replace the $150/MWh breakpoint plan was adopted in its December 15, 2000 order" (FERC Docket No. EL00-95-012, p. 1). The proposed modifications to the market combined a highly regulated uniform price auction, based on "true" costs, with a discriminative auction for higher offers. Additional modifications to expand the regional and temporal coverage of this new market structure were adopted in FERC Order (EL00-95-031). This sequence of "band aids" was not sufficient to prevent the meltdown of the California market. One result of this sequence of failures is that important think tanks like the CATO Institute conclude that "The poor track record of restructuring stems from systemic problems inherent in the reforms themselves." (Van Doren and Taylor 2004). Van Doren and Taylor also recommend a "total abandonment of restructuring and a more thoroughgoing embrace of markets than contemplated in current restructuring initiatives." We disagree with this recommendation. In its place we suggest that:

Good engineering design principles including experimental economic testing should be required of any new electricity market design, before authorizing its use.

[5] See ( ) and ( ) for examples of experimental economics approach to market design. Other works are available at the web sites http://e3rg.pserc.cornell.edu/ and http://www.ices-gmu.net/index.php

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