



July 14, 2006

Dear Mr. Flack and Kolevar:

We are pleased to submit the enclosed report *The Relationship between Competitive Power Markets and Grid Reliability*. This report was prepared in response to a recommendation of the U.S.-Canada Power System Outage Task Force (the Task Force).

The Task Force concluded from its investigation of the August 13, 2003, blackout that restructuring of the bulk power industry was not a cause of the blackout. However, the Task Force did determine that it was appropriate to explore the concerns raised by those who identified restructuring as a contributing factor. To this end, the Task Force included the following recommendation in its report *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*:

The U.S. Department of Energy and Natural Resources Canada should commission an independent study of the relationships among industry restructuring, competition in power markets, and grid reliability, and how those relationships should be managed to best serve the public interest.

The U.S. Department of Energy and Natural Resources Canada have fulfilled the Task Force's directive by: 1) inviting ten issue papers, prepared independently, by industry leaders and technical experts to delineate and critically assess the potential impacts of competition on reliability and to recommend appropriate next steps to address these impacts and 2) seeking public comment through presentation and discussion of these papers at two public workshops and through an open public comment process. The enclosed report presents the results of this process.

We would like to thank experts who contributed their knowledge and time to the development of the issue papers and to the panel presentations and discussion at the workshops. We would also like to thank the individuals and organizations who contributed to the two public workshops, as well as those that provided comments to the electronic forum created for the project.

Sincerely,

David Burpee
Electricity Resources Branch

David Meyer
Office of Electricity Delivery &

Natural Resources Canada

Energy Reliability
U.S. Department of Energy

**U.S.-Canada Power System Outage Task Force
Report on the August 14, 2003 Blackout**

Recommendation 12

**The Relationship between
Competitive Power Markets and Grid Reliability**

**Submitted by
U.S. Department of Energy
and
Natural Resources Canada**

**Submitted to
U.S.-Canada Power System Outage Task Force**

July 2006

Abstract

The U.S. – Canada Power System Outage Task Force concluded that restructuring was not a cause of the August 14, 2003 blackout. However, the Task Force did determine that it was appropriate to explore the concerns raised by those who identify restructuring as a contributing factor. To this end, the Task Force *Final Report* includes Recommendation #12:

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¹ U.S. – Canada Power System Outage Task Force (2004), page 148.

Acknowledgements

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The U.S. Department of Energy and Natural Resources Canada express their gratitude to the authors of the issue papers and presenters at the public workshops:

Jack Casazza, Frank Delea, and George Loehr, Power Engineers Supporting Truth

José Delgado, American Transmission Company

Kellan Fluckiger, Alberta Department of Energy

David Goulding, Independent Electricity Market Operator

Phillip G. Harris, Andrew Ott, Thomas Welch, PJM Interconnection LLC

John P. Hughes, The Electricity Consumers Resource Council

David R. Nevius and Ellen P. Vancko, North American Electric Reliability Council

Robert J. Thomas, Cornell University

Scott Thon, AltaLink

John Wilson, Ontario Electricity Coalition

They also thank the participation and contributions of the individuals and organizations at the two public workshops, as well as those that provided comments to the electronic forum created for the project.

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Acronyms

AC	alternating current
ACE	area control error
AEP	American Electric Power
AESO	Alberta Electric System Operator
AFC	available flowgate capability
AGC	automatic generation control
ANSI	American National Standards Institute
APPA	American Public Power Association
ATC	available transfer capability
ATSI	American Transmission Systems
CAISO	California Independent System Operator
CAEM	Center for the Advancement of Energy Markets
CAL PX	California Public Exchange
CEEMI	Consolidated Edison Energy Massachusetts, Inc.
CEO	chief executive officer
CERTS	Consortium for Electric Reliability Technology Solutions
CMEEC	Connecticut Municipal Electric Energy Cooperative
CMO	Central Market Operator
ComEd	Commonwealth Edison
DOE	U.S. Department of Energy
ECAR	East Central Area Reliability Coordination Agreement
ERCB	Energy Resources Conservation Board
EEI	Edison Electric Institute
ELCON	Electricity Consumers Resource Council
EMS	energy management system
ERCOT	Electric Reliability Council of Texas
ERO	Electric Reliability Organization
EUA	Electric Utilities Act
EUB	Energy Utilities Board
FE	FirstEnergy
FERC	Federal Energy Regulatory Commission
GIS	geographic information system
GWh	gigawatt hour
IBEW	International Brotherhood of Electrical Workers
ICC	Illinois Commerce Commission
IEEE	Institute of Electrical and Electronics Engineers
IESO	independent electricity system operator
IMO	independent electricity market operator
IPP	independent power producer
ISAC	Information Sharing and Analysis Center
ISO	independent system operator

JOA	joint operating agreement
JRCA	joint reliability coordination agreement
km	kilometer
kV	kilovolt
LMP	locational marginal price
LSE	load-serving entity
MAAC	Mid-Atlantic Area Council
MAIN	Mid-America Interconnected Network
MISO	Midwest Independent System Operator
MIP	mixed-integer programming
MMWEC	Massachusetts Municipal Wholesale Electric Company
MW	megawatt
MWh	megawatt hour
MRO	Midwest Reliability Organization
NAESB	North American Energy Standards Board
NARUC	National Association of Regulatory Utility Commissioners
NASA	National Aeronautics and Space Administration
NE-ISO	New England Independent System Operator
NEPOOL	Northeast Power Pool
NERC	North American Electric Reliability Council
NIMBY	not in my backyard
NIPSCO	Northern Indiana Public Service Company
NPCC	Northeast Power Coordinating Council
NRC	National Reliability Center
NRECA	National Rural Electric Cooperative Association
NYPP	New York Power Pool
NUG	non-utility generator
O&M	operations and maintenance
OATT	open access transmission tariff
OPA	Ontario Power Authority
PJM	Pennsylvania-New Jersey-Maryland Interconnection
PPA	Power Purchase Arrangement
PUB	Public Utilities Board
PUHCA	Public Utilities Holding Company Act
PURPA	Public Utility Regulatory Policy Act
RFP	request for proposals
RMR	reliability must-run
RMS	reliability management system
RRC	Regional Reliability Councils
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SCADA	supervisory control and data acquisition
SERC	Southeastern Electric Reliability Council

SMD	Standard Market Design
RRO	regional reliability organization
RTO	regional transmission organization
Southern	Southern Company
SPP	Southwest Power Pool
T&D	transmission and distribution
TDP	Transmission Development Policy
TFO	transmission facility owner
TLR	transmission loading relief
TMR	transmission must run
TVA	Tennessee Valley Authority
UWUA	Utility Workers Union of America
VACAR	Virginia-Carolinas area
VAST	VACAR, AEP, Southern, TVA
VEM	VACAR, ECAR, MAAC
WECC	Western Electricity Coordinating Council

Executive Summary

Some analysts of the causes of the major U.S. – Canada blackout on August 14, 2003 have suggested that restructuring of wholesale electricity markets created the conditions that led to the blackout. These analysts observe that the introduction of intra- and inter-regional competition and trade has led to the transmission of electricity over distances and at volumes not envisioned when the power grid was designed. This change in grid utilization, it is suggested, has created major reliability risks that have not been adequately addressed.

The U.S. – Canada Power System Outage Task Force concluded that restructuring was not a cause of the August 14, 2003 blackout. However, the Task Force did determine that it was appropriate to explore the concerns raised by those who identify restructuring as a contributing factor. To this end, the Task Force *Final Report* includes Recommendation #12:

The U.S. Department of Energy and Natural Resources Canada should commission an independent study of the relationships among industry restructuring, competition in power markets, and grid reliability, and how those relationships should be managed to best serve the public interest.²

The U.S. Department of Energy (DOE) and Natural Resources Canada (NRCan) have fulfilled the Task Force’s directive by: 1) Inviting ten issue papers, prepared independently, by industry leaders and technical experts to delineate and critically assess the potential impacts of competition on reliability and to recommend appropriate next steps to address these impacts and 2) Seeking public comment through presentation and discussion of these papers at two public workshops and through an open public comment process.

The Issue Papers

In “Contributions of the Restructuring of the Electric Power Industry to the August 14, 2003 Blackout,” Jack Casazza, Frank Delea, and George Loehr of Power Engineers Supporting Truth argue that “deregulation and restructuring have had a devastating effect on the reliability of the North American power system and constitute the ultimate root cause of the August 14, 2003.” They offer a number of major findings to support this conclusion: 1) Industry focus has changed from coordination to competition with the major concern being profits rather than reliability; 2) Expenditures and manpower have been reduced; 3) The qualifications of senior managers in the industry and government have shifted away from working knowledge of the technical aspects of power system operation; 4) Individual and

² U.S. – Canada Power System Outage Task Force (2004), page 148.

institutional knowledge, including lessons learned from past blackouts, have been lost; 5) The increased number of players and extensive new regulations have vastly increased the complexity of decision making and operations; and 6) NERC has already watered down its reliability standards, and efforts are now underway to reduce them even further. In brief, people not markets are the key to reliability. Since the ultimate problem has not yet been addressed, the authors argue, the risk of a massive blackout is no lower today than it was in 2003 – despite the passage of the Energy Policy Act of 2005, which will do nothing to enhance reliability. In fact, power system reliability may be even more at risk in the future. They offer a series of recommendations to address the impacts on reliability resulting from these findings.

In “The Blackout of 2003 and its Connection to Open Access,” José Delgado of American Transmission Company, contends that “while moving toward open transmission access and market competition, the U.S. electricity industry allowed confusion to develop regarding actions necessary to maintain the reliability of the power grid and the entities responsible for those actions.” He observes that the introduction of competition into wholesale electricity markets upset a long-standing balance – known as the regulatory compact – between obligations and rights of utility companies and costs and benefits to electricity consumers. He observes that implementation of policies promoting competition created confusion regarding the answer to the question “who is responsible for reliability?” He offers eight recommendations to help appropriately reallocate reliability costs and responsibilities among today’s stakeholders.

In “Competitive Electric Power Markets and Grid Reliability, Something Has Changed Over the Past Decade!,” Kellan Fluckiger of Alberta Department of Energy reviews the fundamental changes that have taken place in the electricity industry. He describes the changed roles, responsibilities, and relationships among the stakeholders involved in supporting the electricity market and in ensuring reliability. He recommends increased future focus on three areas: 1) Developing consensus around the emerging electricity market framework; 2) Defining with clarity the role of the Independent System Operators in relation to oversight organizations, such as regulators, boards, and commissions; and 3) Addressing changing requirements for transmission and acknowledging the importance of ensuring that adequate transmission infrastructure is in place. He concludes “[T]ransmission is a small cost and well worth the investment to secure the significant benefits of an unconstrained market.”

In “Competitive Power Markets and Grid Reliability: Keeping the Promise,” David Goulding of Independent Electricity System Operator observes that the electricity industry is now moving into its second significant transformation. During the first transformation, “governments and stakeholders rushed ahead with enthusiasm, and perhaps some naiveté, to build the first generation of electricity markets.” In the

second transformation, “we are assessing what we have learned, in a broad sense, and developing strategies to help markets transition to a more robustly competitive form.” He offers lessons to guide this second transformation, organized around three major themes: 1) Carefully design markets; 2) Provide safeguards; and 3) Develop transitional mechanisms. He concludes with a short-list of priorities: Develop standards and infrastructure (including advanced technology), reduce seams, and increase harmonization among markets.

In “Relationship between Competitive Power Markets and Grid Reliability PJM RTO Experience,” Phillip G. Harris of PJM Interconnection maintains that “wholesale electric competition enhances, rather than compromises grid reliability.” To those who blame competition for deferred investment and expenditures by the industry, he responds that the factors that caused the August 14, 2003 blackout are the same factors that have caused other major blackouts in the U.S., many of which took place well before the advent of wholesale electricity competition in 1992. Harris describes the ways in which the grid has evolved through the addition of new technologies and the creation of new institutions to deal effectively with the emergence of competitive regional electricity markets. He suggests that large regional markets improve reliability by fostering coordinated regional planning and by making prices transparent across large geographic areas, which helps to harmonize the actions of market participants with system reliability needs.

In “Reliability Risks During the Transition to Competitive Electricity Markets,” John P. Hughes of The Electricity Consumers Resource Council organizes his thoughts around two basic premises of ELCON: “competition and reliability are mutually beneficial to the extent that a reliable grid is necessary to support competitive wholesale markets,” and “the potential innovation and product differentiation made possible by true competition can only enhance reliability.” He expresses concern that grid reliability may be at risk during the transition to competition because adequate market and regulatory safeguards are not yet fully in place. He offers several examples of opportunistic and anti-competitive behavior that he submits pose significant risks to reliability and, as a result, may be eroding public support for competitive electricity markets. Recognizing the reliability and market-power-abuse provisions in the recently enacted U.S. energy legislation as an important first step, he recommends six additional actions by U.S. Congress, the Federal Energy Regulatory Commission (FERC), and/or states to further address these concerns.

In “Ensuring a Reliable North American Electric System in a Competitive Marketplace,” David R. Nevius and Ellen P. Vancko of North American Electric Reliability Council maintain that “if [North American Electric Reliability Council] NERC reliability rules are adhered to, the transmission system can be operated reliably regardless of the demands placed upon it.” Their paper reviews the changes NERC has undergone in responding and adapting to restructuring and the

introduction of competition in the electricity industry, starting with early recognition of the need for legislation to make reliability rules mandatory and enforceable. They describe NERC's activities in anticipation of this legislation and outline the steps and features of the transition that will result from the recent passage of the legislation.

In "Managing Relationships Between Electric Power Industry Restructuring and Grid Reliability," Robert J. Thomas of Cornell University, in considering whether moving to a restructured environment must fundamentally degrade the reliability of the bulk power system, observes that "reliability costs money and the questions are: how much are consumers willing to pay for reliability, and how will payment be extracted?" He notes that the situation is complicated by the recognition that aspects of reliability are a "public good," and, while "efficient markets can be created for private goods... regulation is necessary for efficient use of a public good." He reviews three industry trends that are causes for concern: 1) Increased organizational complexity (which increases the likelihood of bad decisions, especially regarding real-time reliability management); 2) Mid- and longer-term negative impact on innovation from dramatic reductions in research and development spending by the industry; and 3) The looming crisis in manpower as the industry workforce (including academics) ages and potential new entrants seek higher-paying work in other fields. He offers four recommendations to address the immediate challenges posed by these trends.

In "Alberta Electric Industry Restructuring, Implications for Reliability," Scott Thon of AltaLink discusses the restructuring of the Alberta electricity market, focusing on the implications for power system reliability. He describes four areas of concern: 1) Transmission investment and construction have lagged behind generation investment and development; 2) There is increased complexity and, because of under-investment in transmission, there are heightened risks in real-time operations; 3) Several longer-term reliability issues need to be addressed, including the importance of transmission construction as a means to eliminate congestion, the need for proactive transmission planning, and the inappropriateness of relying on request-for-proposal processes to develop transmission projects; and 4) Clear roles and responsibilities must be defined among implementing agencies. He concludes by listing six key elements that should be considered to ensure that industry restructuring does not negatively impact reliability.

In "Sinister Synergies: How Competition for Unregulated Profit Causes Blackouts," John Wilson of Ontario Electricity Coalition maintains that " ...higher costs and the need for greater profits have pushed deregulated power producers to cut costs drastically and to invest where high, short-term returns are more likely rather than focusing on reasonable long-term returns with reasonable cost savings and reliability." He notes that experts, analysis, and performance demonstrate that although deregulation works well in some areas, electricity is not one of them. He

describes significant problems that have resulted from deregulated electricity systems, including reduced reliability focus, insufficient resources, increased complexity, inadequate planning and coordination, reduced transparency, on-the-fly implementation of deregulated systems, and harmful conflicting interests. He recommends that “we put any further deregulation initiatives on hold until we have a better and more detailed understanding of how deregulation is really affecting our electricity system” and that we proceed with a detailed and thorough study of the effects of deregulation on electricity system reliability that is independent of government and energy interests.

Public Workshops and Public Comment

The final element of DOE and NRCan effort to fulfill the Task Force’s Recommendation to conduct an independent study of the relationships among industry restructuring, competition in power markets, and grid reliability, and how those relationships should be managed to best serve the public interest was to provide opportunities for public comment and discussion of the ten issue papers. This was accomplished by conducting two public workshops at which the issues papers were presented and discussed, and through public comment received directly on the issue papers and workshops.

Public workshops were held in Washington, DC and in Toronto, Ontario in the fall of 2005. Both workshops were organized as panel discussions in which groups of 3 or 4 authors presented their papers in the form of responses to selected questions derived from themes raised by their papers. Public comment was received following each panel session.

The first public workshop was held in Washington, DC on September 15, 2005. There were 71 participants at the Washington DC workshop. The second public workshop was held in Toronto, Ontario on September 28, 2005. There were 55 participants at the Toronto, Ontario workshop.

Direct posting of public comment on the issue papers and workshops was provided for on both the DOE and NRCan websites created for the project. The public comment period was open from the time the issues papers were first posted and the workshops were announced until approximately one month following the second public workshop in Toronto. During this period, three comments were received.

Concluding Remarks

DOE and NRCan’s collection of perspectives from industry leaders and technical experts who represent a broad range of interest, along with the solicitation of public

comment, is an important contribution toward our understanding of the impacts of restructuring on grid reliability.

For the purposes of addressing Task Force Recommendation #12, DOE and NRC do not take a position on the relationship between restructuring and reliability beyond the policies already enacted by their respective governments. Notably, since the time this study was initiated, the Energy Policy Act of 2005 has been signed into law directing the Federal Energy Regulatory Commission to certify an Electricity Reliability Organization that will develop and enforce mandatory reliability standards.

Introduction

Some analysts of the causes of the major U.S. – Canada blackout on August 14, 2003 have suggested that restructuring of wholesale electricity markets created the conditions that led to the blackout. These analysts observe that the introduction of intra- and inter-regional competition and trade has led to the transmission of electricity over distances and at volumes not envisioned when the power grid was designed. This change in grid utilization, it is suggested, has created major reliability risks that have not been adequately addressed.

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The U.S. Department of Energy (DOE) and Natural Resources Canada (NRCan) have fulfilled the Task Force's directive by: 1) Inviting ten issue papers, prepared independently, by key industry leaders and technical experts to delineate and critically assess the potential impacts of competition on reliability and to recommend appropriate next steps to address these impacts and 2) Seeking public comment through presentation and discussion of these papers at two public workshops and through an open public comment process.

Section 2 provides background for the major themes discussed and expanded upon by the issue papers and public comment process. These include the organizations and principles involved in electricity grid reliability management, as well as the changes that restructuring and the introduction of competition in bulk power markets have led to in electricity production, electricity commerce, and industry organization. An early draft of this section was prepared in order to provide a common base of information for the issue paper authors to drawn upon (and avoid having to repeat) in preparing their papers. The material was intended to stimulate discussion by summarizing changes occurring in the electricity sector, potential implications of these changes for reliability, and how the management of reliability has developed to address these changes.

¹ U.S. – Canada Power System Outage Task Force (2004), page 148.

Section 3 presents each of the ten invited issue papers in their entirety. Each paper was prepared as an independent contribution by its authors expressly for this study. A technical editor provided suggestions to the authors on early drafts of their papers. However, the final text of each paper is presented exactly as approved by each author (or group of authors). Appendix A contains short biographies of the issue paper authors.

Section 4 describes the public workshops held in Washington, D.C. on September 15, 2005 and in Toronto, Ontario on September 28, 2005 and public comment process through which the papers were presented and discussed. Section 13 is augmented by three appendices. Appendices B and C provide the agenda, and list of participants for each of the two public workshops.² Appendix D contains the public comment received through the DOE and NRCAN websites.

DOE and NRCAN's collection of perspectives from industry leaders and technical experts who represent a broad range of interest, along with the solicitation of public comment, is an important contribution toward our understanding of the impacts of restructuring on grid reliability.

For the purposes of addressing Task Force Recommendation #12, DOE and NRCAN do not take a position on the relationship between restructuring and reliability beyond the policies already enacted by their respective governments. Notably, since the time this study was initiated, the Energy Policy Act of 2005 has been signed into law directing the Federal Energy Regulatory Commission to certify an Electricity Reliability Organization that will develop and enforce mandatory reliability standards.

² Transcripts can be downloaded from:

DOE website: <http://www.energetics.com/reliability.html>

NRCAN website: <http://www2.nrcan.gc.ca/es/erb/erb/english/conference.asp>

Background on Electricity Reliability, Industry Restructuring and Competition in Bulk Power Markets

This section provides background for the major themes discussed and expanded upon by the issue papers and public comment process. These include the organizations and principles involved in electricity grid reliability management, as well as the changes that restructuring and the introduction of competition in bulk power markets have led to in the ways that electricity is produced, sold, and managed. An early draft of this section was prepared in order to provide a common base of information for the issue paper authors to draw upon (and avoid having to repeat) in preparing their papers. The material is intended to stimulate discussion by summarizing changes occurring in the electricity sector, potential implications of these changes for reliability, and how the management of reliability has developed to address these changes.

Electricity Reliability

The unique physical characteristics of electricity create special challenges for ensuring reliable delivery from generators to customers. Within the North American electricity transmission system's three vast, interconnected networks, electricity flows according to the laws of physics without regard to the ownership of the lines or the contracts governing input and withdrawal of power. Because electricity cannot be stored economically, the generation and transmission system must respond in real time to continuous fluctuations in electricity consumption. Perhaps most challenging of all, electricity moves at speed of light; therefore, problems originating in one part of the grid are felt instantly throughout. Addressing these problems requires specialized systems and technologies that must be coordinated in real time and must sometimes operate automatically without human intervention because failure to immediately address grid problems can lead to power outages or interruptions. The physical characteristics of electricity require that we develop effective ways to measure system reliability, institutions to oversee and manage reliability, and planning and operating procedures to ensure reliability.

Distribution versus Transmission Outages

Reliability is measured by the absence of interruptions in electricity service. Interruptions in electricity service are classified according to their duration, frequency, and scope. The interruptions with which consumers are most familiar are typically limited in geographic scope and duration. They occur most frequently on a single branch within a utility's low-voltage radial distribution system [e.g., at 12 kilovolts (kV)], so only those customers receiving electricity service from that branch are affected. These interruptions are most often caused by lightning strikes, accidental contact between distribution lines and trees, animal electrocutions within

substations, or errors by technicians working on lines or within substations. These events usually last less than one hour. Anecdotal evidence suggests that events originating within a utility's distribution system are responsible for more than 90 percent of all interruptions experienced by customers.

Far less frequent but potentially much more widespread are interruptions affecting the high-voltage transmission system (i.e., at 69 kV and above). In contrast to the distribution system, which is configured radially, the high-voltage system is a network that overlays and interconnects multiple distribution systems. Because of this configuration – akin to a system of canals – the unplanned loss of a major generating station, transmission line, or substation on the transmission system leads to power being automatically rerouted over the remaining lines. To compensate for lost generation facilities, some generators are selected to stand by, ready to generate extra power at a moment's notice; in the event of a disturbance, these standby generators must immediately inject power to the system. Automatic protective devices operate instantaneously to limit the spread of a disturbance.

Customers may not lose electricity service as a result of a disturbance on the transmission system because the distribution systems to which they are connected may continue to receive power as electricity flow is rerouted through a new combination of transmission and generation facilities that have been unaffected by the disturbance. However, when events overwhelm the ability of the transmission and generation systems to withstand, reroute, and recover -- often because multiple system elements are lost, for example as the result of a hurricane or other natural disaster -- power may be lost catastrophically over large geographic areas. This type of disruption is referred to as a cascading outage, and the widespread nature of the damage caused by the initiating event may delay efforts to restore service. For example, a hurricane can disrupt multiple forms of infrastructure, such as communications, water, and roads, which may lead to a prolonged power outage or blackout.

The essays in this report focus primarily on the reliability of the bulk transmission system because this system caused and spread the effects of the August 14, 2003 blackout. The impact of bulk-power-market restructuring and competition on distribution system reliability (and power quality) is a related and important issue, but it is not addressed in this report.

Reliability Management

Managing the reliability of the North American electricity system involves coordinated yet essentially voluntary efforts of the many firms involved in generation, transmission, and distribution of electricity. As described above, the very nature of electricity and the physical systems that have been developed to

transport it mean that the actions of each firm that uses the transmission grid can directly affect the ability of all others to use the grid. Thus, ensuring reliability is a shared, community objective. Many believe there is an inherent tension between this objective and the objectives of participants in competitive markets who seek to further their own individual interests, and that this tension can only be addressed by making reliability requirements mandatory for all participants. On August 8, 2005, the U.S. Energy Policy Act of 2005 was signed into law; this legislation includes provisions that initiate the transition to mandatory reliability standards.

The principal organizations involved in collectively ensuring reliability include:

The North American Electric Reliability Council (NERC) - NERC was formed in 1968 by the electric utility industry in response to the 1965 Northeast Blackout. NERC establishes reliability standards through consensus and monitors compliance with them. As noted above, NERC relies on voluntary compliance and has no enforcement authority other than peer pressure. NERC is governed by an independent board.

Regional Reliability Councils (RRCs) - The 10 RRCs jointly own and fund NERC and adapt NERC standards to the needs of their regions. In 1994, the regional councils opened up their membership to independent power producers (IPPs), power marketers, and electricity brokers. In 1996 NERC, opened its board and committees to voting participation by those entities as well as end-use customers.

Control Areas - Control areas are the basic operational entities that are subject to NERC and RRC standards. Control areas were traditionally defined by utility service-area boundaries. Generation and loads are regulated in real time within control areas to maintain reliable operation of the system. Control areas are linked with each other and maintain interchange schedules through transmission interconnection tie-lines and direct generation operations. They also support the reliability of the interconnection. There are approximately 140 controls areas in North America.

Reliability Coordinators - Reliability coordinators assess operations and coordinate emergency responses for a group of control areas. They do not participate in wholesale or retail merchant functions. They were established by NERC in 1996 to oversee reliability management over a wide region. There are currently 18 reliability coordinators in North America.

Reliability Adequacy and Security

NERC defines reliability in terms of the performance of the elements of the bulk electricity system that result in power being delivered to customers within accepted standards and in the amounts desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electricity supply. Electricity system reliability is addressed by considering two basic and functional aspects of the system, adequacy and security:

Adequacy – the ability of the electricity system to meet the aggregate electricity demand and energy requirements of customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.

Security – the ability of the electricity system to withstand sudden disturbances, such as short circuits or unanticipated loss of system elements.

NERC standards and policies for planning and operation address both the adequacy and security of electricity service. For example, NERC's planning standards require that control area operators ensure, on an ongoing basis, both the adequacy of expected supply relative to expected demand and the security of supply following the hypothetical loss of one or more key system elements (e.g., loss of a large generator, major transmission line, or substation). NERC's operating procedures require that control area operators ensure adequacy by carefully matching supply and demand in real time to keep an interconnection's frequency within tight bounds, and ensure security by maintaining operating reserves to enable quick recovery from contingencies.

Adequacy is assessed and ensured over multiple time scales. NERC publishes an annual assessment of reliability that examines long-term adequacy by comparing projected annual capacity margins (the difference between expected generation capacity and expected loads) for several years into the future. On a daily basis, control area operators review the next day's forecast of loads, scheduled maintenance of facilities, and proposed generation schedules. Based on this information, operators assess, and, as necessary, adjust the next day's dispatch of generation to match expected loads. On the day of operation, operators ensure a close match between actual generation and load in real time by directing adjustments in generator output; these adjustments are sometimes triggered automatically by deviations in system frequency.

Security is assessed primarily a day ahead and in real time. On a day-ahead basis, operators ensure that adequate reserves are available to allow the system to rapidly return to a secure state following the unplanned loss of one or more key system

elements. These assessments must be updated in real time throughout each day in response to actual operating conditions.

Contrasting the cause of the rolling blackouts in California in summer 2000 and winter 2000-2001 with the cause of the Northeast Blackout on August 14, 2003 illustrates the distinctions between planned and unplanned power interruptions as well as the subtle distinctions between the adequacy and security aspects of reliability.

The rolling blackouts experienced in California in 2000 and 2001 were planned in the sense that they were the result of deliberate actions taken by the control area operator, the California Independent System Operator (CAISO). During this period, operators deliberately shed loads in a controlled manner to respond to the problem of inadequate operating reserves. Operating reserves provide for system security and consist of generators that stand ready to step in and serve load instantly after the loss of a major system element. The amount of reserves required depends on the total load being served. Rolling blackouts were initiated to reduce overall system loads to a level consistent with the operating reserves that were available at the time. In other words, failure to shed those loads would have placed the system in an insecure state in the sense that the system might not have been able to withstand the unplanned loss of a major element. The system's inability to withstand such a loss could have caused major portions or even the entire system to collapse leading to a prolonged blackout. To avoid this situation, service to a predetermined, small number of customers was deliberately curtailed so that the system could reliably continue delivering power to the remaining customers.

In contrast, the Northeast Blackout on August 14, 2003 was unplanned. It was the result of numerous violations of NERC standards and policies, including the unwitting operation of the First Energy control area in an insecure state. NERC operating policies require control area operators to determine whether their systems are in a secure state (i.e., able to withstand the loss of a major system element), and, if the system is found to be insecure, to take action to restore the security of the system within 30 minutes. Because of computer malfunctions, First Energy did not know it had lost 345-kV lines and was as a result operating in an insecure state. In addition, First Energy had been operating with inadequate voltage reserves, which contributed to the insecurity of the system. When it became (or should have become) clear to First Energy that it was operating in an insecure state (following the loss of Harding-Chamberlin line and before the loss of Sammis-Star line), First Energy did not take remedial action, such as deliberately shedding load (i.e., instituting rolling blackouts), to attempt to restore the system to a secure state.

In summary, in California in 2000 and 2001, the CAISO, when faced with inadequate operating reserves, which posed a threat to its ability to operate the system in a

secure fashion, deliberately initiated load shedding in order to increase the adequacy of its reserves and, thereby, return operations to a secure state (a state that would enable them to continue providing service to the majority of customers following unplanned loss of a key system element). In Ohio in 2003, First Energy unknowingly operated its system in an insecure state (a state in which it did not know that it had lost key transmission lines and at the same time did not have adequate reactive power reserves in order to respond to these losses), which ultimately contributed to its operators inability to restore the system to a secure state or prevent the spread of the blackout.

Industry Restructuring and Competition in Bulk Power Markets

Electricity industry restructuring and competition in bulk power markets encompass a broad range of topics. For simplicity, we use these terms to refer to the changes experienced by the industry starting from about the time of the Public Utilities Regulatory Policies Act of 1978 (PURPA) in the U.S. In Canada, there is no single corresponding national law comparable PURPA because electricity is regulated primarily by provincial governments. However, some of the industry changes that we refer to as restructuring and competition have taken in specific provinces. The pace and consistency of regulatory reform in the Canadian provinces have been uneven, so different jurisdictions have experienced different degrees of change.

Prior to PURPA and regulatory reforms in some Canadian provinces, electricity was generated and transmitted primarily by vertically integrated firms to captive franchises of customers. Early high-voltage transmission was dedicated to connecting a remote generating station to an identified base of customers. In simple terms, this arrangement is like having a coal-fired power generation plant operating next to the coal mine that provides a dedicated, continuous supply of fuel for the plant. Interconnections among companies were developed to realize economies of scale through both joint access to remote resources and increased utilization of existing resources. Interconnections enhanced reliability, by enabling the sharing of generation during emergencies, but also introduced new challenges for reliability, by tying the fate of multiple systems closely together.

Since PURPA and the regulatory reforms in some Canadian provinces, there have been many changes in the traditional system. Rather than attempting to define exhaustively what is meant by “restructuring” and “competition” in electricity markets, we focus on three observable trends: changes in electricity production, electricity commerce, and industry organization.

Changes in Electricity Production/Generation

Changes in electricity production and generation are at the heart of industry restructuring and the introduction of competition in bulk power markets. These changes have resulted from the activities of new classes of generation owners and operators (IPPs and merchant power producers) and of traditional utility owners and generation operators responding to these developments.

New generating stations are no longer planned and built exclusively by vertically integrated firms. This has led to dramatic changes in the timing, location, and technology of new generation. NERC annual reliability assessments identify uncertainty about the timing of new generation construction by IPPs and merchant producers as a significant source of uncertainty about the expected adequacy of future capacity margins.

Importantly, it is now difficult to harmonize transmission system planning with generation planning by IPPs and merchant producers because separate decision makers are now involved and generation can be built much more quickly than transmission.

In addition, in the absence of market signals on the locational value of transmission, new generation is sometimes located based on access to fuel supplies without regard for the availability of transmission. This practice can lead to problems delivering the power from the new generation facility. The existing, slowly changing transmission infrastructure was not designed to accommodate the addition of new generation in this manner.

Finally, a significant component of the new fleet of generation being built both by merchants and utilities consists of lightweight, natural-gas-fired, combined-cycle plants. These plants are displacing and, in some cases, hastening the retirement of older steam-driven turbines. This change in the technology base for generation has important and not fully understood implications for reliability. The loss of older, steam-generating units decreases the “inertia” inherent in the power system (often at strategic locations within the system). This inertia has, in the past, been the primary means for stabilizing the frequency of interconnections. Early retirement also influences assessments of the long-term adequacy of generation capacity.

Generators are also being run differently than they were in the past. Many plants ramp their output up and down much more frequently in response to market conditions. As a result, some plant owners report greater degradation of plant capabilities because of the increased mechanical stresses on generating equipment; this deterioration may lead to early retirements of generating capacity.

Operational flexibility is also now increasingly specified in contractual terms. However, as we discovered during the investigation of the August 14, 2003 blackout, these terms sometimes leave out or do not adequately address the provision of reliability services, such as voltage support, which may require a plant to curtail real power output. The Federal Energy Regulatory Commission (FERC) has recently prepared an issue paper and held a technical conference on this topic.

Changes in Electricity Purchase and Sales

Changes in the way electricity is bought and sold increasingly represent the “medium” through which information influencing generation decisions is transmitted. In place of the past practice of vertical coordination of generation and transmission through decision making within a single firm, we now have market prices and bilateral contracts between and among firms. For example, in the U.S., the creation of the Open-Access Same-time Information System (OASIS) as a venue for publicly posting available transfer capability has been a central element of FERC’s vision for providing generators non-discriminatory access to the transmission system. The high-voltage transmission system is increasingly being thought of as a common carrier, the infrastructure over which wholesale electricity transactions are executed. The volume, scope, and nature of electricity transactions have all changed as a result of restructuring and the introduction of competition in bulk power markets.

The volume of wholesale transactions and the quantities of electricity traded have grown dramatically. Moreover, the scope of these transactions is much greater than in the past and often encompasses more than one RRC. Reliability coordinators were created by NERC in part to augment control area operations by providing a broad, regional perspective from which to monitor these impacts and ensure reliability.

Control areas must now explicitly account for wholesale market activities in both day-ahead planning and same-day operations. System operators report that they must increasingly accommodate electricity trades that are imposed upon their systems and to which they are not even parties (sometimes called loop flow). In addition, operators report new challenges to maintaining reliability in the face of operating configurations that are driven by competitive forces and that operators have not previously encountered, or, more importantly, that have not been previously studied.

The nature of electricity transactions has also changed dramatically. Foremost among these changes is that the transformation of electricity into a commodity has required careful “unbundling” of closely related (and from some observers’ perspectives, inherently inseparable) reliability-related aspects of electricity delivery, known generically as “ancillary services.” In traditional operations, deployment of

these services was implicit in the overall generation dispatch process. Today, the definitions for these services have been or are currently being formalized, and their provision is sometimes treated separately from bulk power. In some cases they are even treated as separate market commodities.

In addition, standardized wholesale products for bulk power have been developed for multi-hour blocks of electricity. This has led to reliability concerns during transition periods when the blocks begin and end. Because of mechanical constraints on generators' abilities to ramp up and down quickly, significant frequency excursions have been encountered during these "shoulder" periods.

While electricity trade conducted using the North American interconnected transmission systems has changed dramatically, the underlying physical transmission infrastructure has changed very little. New investment in transmission infrastructure is reported to be at an all-time low compared to past trends. Many observers express concern that there is significant under-investment in transmission and that this has impeded the development of competitive markets for bulk power.

Some argue that there are now significant bottlenecks in the transmission system, which have led to increased (and unintended) reliance on emergency reliability procedures that curtail economic transactions (e.g., transmission load relief or TLR). It has also been argued that these bottlenecks have provided opportunities for abuses of market power by generators. Both the operating problems created by bottlenecks (and remedies available to address them) and the opportunities bottlenecks create for abuse of market power hamper the development of competitive wholesale bulk power markets.

System operators report that the great new challenge they face in maintaining reliability is having to make do with less. That is, they are being asked to accommodate increased trading volumes with an aging and very slowly expanding transmission infrastructure. We will return to this theme in the following subsection.

Changes in Transmission-Management Institutions and Organizations

Changes in the institutions that manage transmission are not generally visible to consumers, but these changes nonetheless underlie the significant changes in electricity production and sales described above. As a result of FERC Orders 888 and 889, all vertically integrated owners of generation and transmission in the U.S. have been required to functionally unbundle the operation of these two classes of assets. As discussed earlier, many firms responded by selling off their generation assets and forming unregulated generation-owning subsidiaries that operate outside the traditional vertically integrated market.

There have been similar initiatives to functionally unbundle utilities and monopolies in Canadian provinces. In Alberta and Ontario, the functional unbundling of vertically integrated utilities and monopolies was a precursor to a movement toward wholesale and retail competition. Other provinces have made similar changes without moving toward retail competition. These initiatives have led to a separation in generation and transmission functions and encouragement of greater competition in generation. Additional motivation to unbundle generation and transmission functions has come from FERC Order 888's effects on Canadian exporters: Canadian transmission companies who wish to obtain a FERC license to sell electricity in the U.S. wholesale markets are required to give U.S. marketers access to their transmission facilities. Unbundling of generation and transmission assets in the U.S. and Canada has had a great impact on the operation of these assets.

In several regions of the U.S. and Canada, Independent System Operators (ISOs) have been created to operate (but not own) transmission assets in a coordinated manner. In most cases, ISO functions have also included the operation of formal wholesale electricity markets. Recently, many of these ISOs have sought to increase their responsibilities (e.g., to include regional transmission planning) and, in the U.S., have become certified by FERC as Regional Transmission Organizations (RTOs). Several features of these newly created organizations have significant implications for reliability, as described in the following subsections.

Geographic Scope and Complexity of Coordination. The footprint of ISOs and RTOs is geographically broad. They were formed by merging formerly separate control areas into a single large control area (e.g., CAISO), the expansion of a single control area to include others [e.g., the Pennsylvania-New Jersey-Maryland Interconnection (PJM)] or the amalgamation of formerly distinct control areas (e.g., the Midwest ISO (MISO), and Alberta Electric System Operator (AESO)). In two instances (PJM and MISO), the newly formed entities span multiple RRC boundaries. In some cases, the ISO or RTO is both the control area operator and the reliability coordinator [New England ISO (ISONE), New York ISO (NYISO), CAISO, Electric Reliability Council of Texas (ERCOT), AESO, and Independent Electricity System Operator (IESO)]. In other case, the ISO or RTO is only the reliability coordinator (MISO). In still other cases, the ISO or RTO is the reliability coordinator for all of its geographic footprint but functions as the control area operator for only portions of its footprint (PJM).³ In short, ISOs and RTOs manage much larger systems than in the past, and there is greater complexity in coordinating information and operations among control areas and reliability coordinators.

³ Even within control areas, there is often a division of responsibility between the control area operator and the actual operators of a utility's transmission system.

In Canada, the history of ISO formation has been different than in the U.S. Canadian ISOs have resulted primarily from provincial restructuring initiatives. In Alberta, for example, the unbundling of generation and transmission resulted initially in the formation in 1998 of the entity now known as AESO. In Ontario, the unbundling of the former Ontario Hydro resulted in the formation of the IESO, which began operating with the opening of the Ontario market in May 2003 [initially known as the Independent Electricity Market Operator (IMO), now referred to as the IESO]. In October 2004, the New Brunswick System Operator commenced operations. In other provinces, the transmission operations of integrated utilities have been separated from generation operations, consistent with providing open access.

Congestion Management. The creation of formal markets for wholesale electricity trade has led to standardization in electricity products (some dimensions of which have already been mentioned above). The most relevant to the issue of reliability is the introduction of market-based approaches for congestion management by several ISO/RTOs (PJM, ISONE, NYISO, MISO). Congestion arises when, because of physical limits on transmission system capacity (expressed in terms of potential violations of reliability limits), all requested trades cannot be executed. Rationing the available transmission through market-based mechanisms in principle allows the self-interest of market participants to establish a fair allocation of trades based on the relative value of transmission to each participant. This is in sharp contrast to the traditional approach of relying on administrative rules (TLRs) that do not explicitly accommodate differences in the market values that participants place on transmission service.

Seams. The creation of large, formal, distinct wholesale markets alongside one another and adjacent to traditional vertically integrated utility operations has led to market “seams” issues. Seams refer to differences in product definitions and business practices that must be addressed as power moves through different, coexisting institutional forms en route from seller to buyer.

Independent Transmission Owners. Within ISO and RTO footprints, independent transmission owners have been created as a form of corporate ownership for transmission assets that is distinct from the traditional, vertically integrated form of ownership. These firms are stand-alone, for-profit⁴ corporate entities that plan, finance, build, operate, and maintain transmission assets. This type of asset ownership allows the market to value the very different risk-return profile of transmission separately rather than as part of a bundled mix with other aspects of the business, as is the case in vertically integrated firms.

⁴ All current ISOs and RTOs have been organized as not-for-profit firms

Despite all the organizational innovation described in the preceding subsections, many analysts remain concerned that the current transmission system is inadequate and that significant new investment is needed to maintain reliability and enable greater electricity trade. Some suggest that continued regulatory uncertainty regarding the future organization of bulk power markets makes it difficult to finance new transmission. Others suggest that local opposition makes it difficult to construct new transmission facilities.

Summary

The task of grid operators and of the reliability standards that guide their actions is to reliably operate the system that is before them. Their job is not to pine for the system and operations they once had, or hope to have in the future.

Restructuring means that things are changing and, consequently, reliability standards and operating practices need to be reviewed and perhaps modified in light of these changes. However, this does not mean that the system cannot be run with the same high level of reliability with appropriate standards and operating procedures. Notably, since the time this study was initiated, the Energy Policy Act of 2005 has been signed into law directing the Federal Energy Regulatory Commission to certify an Electricity Reliability Organization that will develop and enforce mandatory reliability standards.

Issue Papers

The principal element of DOE and NRC's effort to fulfill the Task Force's recommendation to conduct an independent study of the relationships among industry restructuring, competition in power markets, and grid reliability, and how those relationships should be managed to best serve the public interest was to invite industry leaders and technical experts to prepare issue papers that delineate and critically assess the potential impacts of competition on reliability and recommend appropriate next steps to address these impacts.

This section presents each issue paper in its entirety. Each paper was prepared as an independent contribution by its authors expressly for this study. A technical editor provided suggestions to the authors on early drafts of their papers. However, the final text of each paper is presented exactly as approved by each author (or group of authors). Appendix A contains short biographies of the issue paper authors. The ten issues papers are:

"Contributions of the Restructuring of the Electric Power Industry to the August 14, 2003 Blackout" by Jack Casazza, Frank Delea, and George Loehr, Power Engineers Supporting Truth

"The Blackout of 2003 and its Connection to Open Access" by José Delgado, American Transmission Company

"Competitive Electric Power Markets and Grid Reliability, Something Has Changed Over the Past Decade!" by Kellan Fluckiger, Alberta Department of Energy

"Competitive Power Markets and Grid Reliability: Keeping the Promise" by David Goulding, Independent Electricity Market Operator

"Relationship between Competitive Power Markets and Grid Reliability PJM RTO Experience" by Phillip G. Harris, PJM Interconnection LLC

"Reliability Risks During the Transition to Competitive Electricity Markets" by John P. Hughes, The Electricity Consumers Resource Council

"Ensuring a Reliable North American Electric System in a Competitive Marketplace" by David R. Nevius and Ellen P. Vancko, North American Electric Reliability Council

"Managing Relationships Between Electric Power Industry Restructuring and Grid Reliability" by Robert J. Thomas, Cornell University

“Alberta Electric Industry Restructuring, Implications for Reliability” by Scott Thon, AltaLink

“Sinister Synergies: How Competition for Unregulated Profit Causes Blackouts” by John Wilson, Ontario Electricity Coalition

Contributions of the Restructuring of the Electric Power Industry to the August 14, 2003 Blackout

Jack Casazza, Frank Delea, and George Loehr
Power Engineers Supporting Truth

Purpose

This report addresses whether the restructuring of the electric utility industry in the United States, and most specifically in the Midwest Independent System Operator (MISO) area, contributed to the August 2003 blackout in northeastern North America.

There have been numerous after-the-fact reviews of the August 2003 blackout. The various institutional reports by the Department of Energy (DOE), North American Electric Reliability Council (NERC), East Central Area Reliability Coordination Agreement (ECAR), etc., addressed the cause of the blackout by looking one step beyond the most immediate causes. As noted in Chapter 3, page 17 of the April 2004 Final Report of the U.S. Canada Power System Outage Task Force:

A dictionary definition of “cause” is “something that produces an effect, result, or consequence.”¹ In searching for the causes of the blackout, the investigation team looked back through the progression of sequential events, actions and inactions to identify the cause(s) of each event. The idea of “cause” is here linked not just to what happened or why it happened, but more specifically to the entities whose duties and responsibilities were to anticipate and prepare to deal with the things that could go wrong. Four major causes, or groups of causes, are identified (see box on page 18). Although the causes discussed below produced the failures and events of August 14, they did not leap into being that day. Instead, as the following chapters explain, they reflect long-standing institutional failures and weaknesses that need to be understood and corrected in order to maintain reliability (DOE 2004).

Although this quote suggests that the investigation focused on underlying causes of the blackout, the post-blackout reviews did not specifically address the true root causes, as illustrated by the following extracts from two ECAR reports.

- *ECAR Investigation of August 14, 2003 Blackout by Major System Disturbance Analysis Task Force - Technical Report*

“It should be noted that the pursuit of the root causes to the above factors was not within the scope of this MSDATF effort, and hence, root causes are not addressed in the [Major System Disturbance Analysis Task Force] MSDATF Technical Report.”

- *ECAR Investigation of August 14, 2003 Blackout by Major System Disturbance Analysis Task Force - Recommendations Report*

“The technical analysis of what happened in ECAR was done by the ECAR Major System Disturbance Analysis Task Force (MSDATF), which focused specifically on the system behavior during the events leading up to and through the blackout, on the system response to the various events, and on the behavior of the protective relaying systems as the events progressed throughout the afternoon of August 14.”

The post-blackout reviews attempted to determine what happened or didn't happen from a technical perspective. They did not take the next step and ask why – what managerial decisions were made, or not made, that brought about the more immediate causes of the blackout.

For example, tree contact was identified as an immediate cause of power line trippouts. This was explained by unacceptable right-of-way maintenance practices. What was not pursued was why the companies involved had decided on their right-of-way maintenance practices. Could it have been to maximize immediate profits? Similarly, inadequate situation awareness has been identified as another immediate cause. This was explained, in part, by deficiencies in the analytical capabilities of control centers, communication protocols, training, etc. However, the reasons for these deficiencies were not pursued. Could the reasons have included decisions to keep costs down so as to show better financial results? Could there have been a decision to “speed things up” when establishing MISO, in reaction to external pressures to establish a new market structure, before all physical and management systems were in place?

Unfortunately, the information required to answer these broader questions is not publicly available and these questions have not even been asked, nor have secondary sources of information (e.g., maintenance expenditures as found in required

company submissions to the Federal Energy Regulatory Commission (FERC)) been reviewed.

This report attempts to lay out some of the pertinent questions that are still unanswered and, where possible, supply relevant information and conclusions related to these questions.

Basic Approach

The review presented in this report was conducted by a group of engineers with extensive high-level experience in the electric power industry and access to information from several hundred individuals involved in the industry. While it was triggered by the August 14, 2003 blackout, it has necessarily involved a more general concern with how national policies have affected the reliability of electricity service to American consumers. It considers the roles of industry and government, particularly FERC. It focuses on reliability, examines the responsibilities and failures of NERC, includes brief discussions of the government's investigation of the August 14, 2003 blackout, and calls attention to some as-yet unanswered questions. It is based on two essential ingredients:

- When comparing alternatives, characterize them correctly. In reviewing the effect of deregulation on the August 14th blackout, it is essential that comparisons be made based on accurate information about prior procedures. Unfortunately, many who make such comparisons often have very little knowledge of past procedures.
- Avoid being influenced by political, commercial, or personal power concerns. The most precious thing that anyone can bring to a review of policy, such as this report, is to be an honest witness to what he or she knows.

Executive Summary

Deregulation and the concomitant restructuring of the electric power industry in the U.S. have had a devastating effect on the reliability of North American power systems, and constitute the ultimate root cause of the August 14, 2003 blackout. Specifically, deregulation and restructuring have led to:

- Changes in focus from long-term optimization and inter-system coordination and reliability to total dependence on immediate profits and the efficacy of "the market."

- Change in technical qualifications of those holding management positions in electric power organizations and government policy makers and regulators; this change affects entire organizations.
- Reductions in personnel at electric power organizations and companies.
- Failure to make adequate technical analyses including risks when setting government policies.
- Increased complexity of operations because of separation of generation and transmission functions, the large increase in the number of organizations involved, and the establishment of additional levels of responsibility in the operation/control process.
- Dilution of management responsibility, including too many entities in the management structure with veto power.
- An almost fundamentalist reliance on markets to solve even the most scientifically complex problems.
- Decreased emphasis on the importance of strong reliability standards, and a trend toward lower standards; this is most pronounced in the very organization charged with maintaining reliability –NERC – aided and abetted by FERC.
- Dispersed, fragmented control of the bulk power system in the Midwest.
- A patchwork quilt of overlapping jurisdictions among marketing areas, Independent System Operators/Regional Transmission Organizations (ISOs/RTOs), and regional reliability councils in the Midwest
- Reductions in, or outright elimination of, training including training of operators.
- Continuation of the historical problem of geo-electrically small control areas in the Midwest, despite the creation of the MISO, which, in the context of operations on August 14, 2003, appeared to be little more than a toothless shell.

Unless the root causes of the August 14, 2003 blackout are addressed and the trend toward lower standards reversed, the likelihood of future blackouts will increase.

The DOE/Canadian report demonstrates the dominance of market participants and lack of government concern about the root causes of the blackout.^{1,2} Both are also clearly illustrated by the almost two-year delay in the investigations, and discussions that are taking place through the competition and reliability study of which³ this paper is part.

Despite its “spin”, the Energy Policy Act of 2005 does nothing to address the root causes of the 2003 blackout, and hence will do nothing to enhance reliability.

Change in Industry Structure

To understand the changes that have taken place in the structure of the electricity industry, it is necessary to compare current and prior procedures and examine the increased complexity of today’s system relative to the system of the past.

Prior Procedures

From the installation of inter-regional transmission ties in the 1960s until the start of restructuring/deregulation in the 1990s, generation and transmission were planned, designed, and operated on a regionally coordinated basis (Casazza 1993; Rosen 2003). Most individual power companies were vertically integrated, so development of generation and transmission was coordinated. Installation of generation took into account transmission limits, and installation of transmission took into account generation needs. Hierarchical organizations (power pools) evolved covering multi-company areas and each having limited numbers of participants; e.g., the Pennsylvania-New Jersey-Maryland Interconnection (PJM), New York Power Pool (NYPP), and New England Pool (NEPOOL). Power pools in turn combined to form regional reliability councils; e.g., Mid-Atlantic Area Council (MAAC), ECAR, and Northeast Power Coordinating Council (NPCC). These councils coordinated through organizations such as MEN (consisting of MAAC, ECAR, and NPCC), VEM (consisting of VACAR, ECAR, and MAAC), and VAST (consisting of VACAR, American Electric Power [AEP], Southern, and Tennessee Valley Authority [TVA]). Reliability criteria, monitoring and enforcement were accomplished by the regional councils, which had boundaries congruent with planning and operating

¹ DOE personnel have indicated they had more important things to look into in correspondence with the authors (Kolevar 2005).

² The Congressional Research Service Report to Congress on Electric Utility Reform update of April 21, 2005 does not discuss such issues as industry behavior and its impact on reliability (Abel 2005).

³

organizations. Inter-regional coordination was accomplished by organizations such as MEN, VEM, and VAST.

The various organizations communicated often and effectively and cooperated both on real-time operating basis and on a longer-term planning basis. Sales and purchases of power were conducted through these hierarchal organizations, and each organization was well aware of conditions in other systems that could affect it. Each system's plans were coordinated with those of its neighbors.

Changes Resulting From Restructuring

However, during the past 15 years, the structure – indeed the very underpinnings – of the electric power industry have changed. The following phenomena are key indicators of the changes in the industry's structure:

- The functional separation of generation and transmission within companies as mandated by Order 888. Reliable planning and operation of a bulk supply system requires full coordination between generation and transmission; this functional separation made coordination much more difficult.⁴ In most companies system planning departments were split up or disbanded. Typical organizational impacts were:
 - The diffusion of best technical knowledge which in the past was centered in planning departments.
 - Severe reductions in personnel in generation and transmission, including encouragement of senior personnel to take early retirement. These reductions effectively ended the transfer of essential expertise from one generation to the next.⁵
 - Reductions in training as a means of reducing costs.

⁴ In Con Edison, this resulted in disassembling the Planning organization that had reported to one Vice President into three entities reporting to three different Vice Presidents. In AEP, the System Planning Department, which had reported to the Chief Executive Officer for many years, was disbanded and its functions were assigned to different organizations and eventually eliminated.

⁵ In the United States, reductions in personnel have been greater in the deregulated portions of the industry than in those still under regulation. While some reductions in labor are appropriate at times, others are the result of a focus on immediate profits and contributed to the blackout. A competent analysis of the effects of such labor reductions has been provided by the IBEW and the UWUA (Delea and Casazza 2004; U.S. Department of Labor; Neederjohn 2003; Hunter 2000).

- The divestiture by many private utilities of their generation resources in response to regulatory pressures. Many companies either “spun-off” their generating assets into unregulated affiliates or sold them to third parties. This increased number of “players” greatly complicated the system planning process and diffused responsibility for maintaining a reliable system.
- The transfer of control of transmission assets in response to federal regulatory requirements to ISOs/RTOs, the majority of whose boards were made up of individuals with no knowledge of power system operational or reliability issues.⁶
- Entrance of merchant power plants into the power system. This also complicated the system planning process and diffused responsibility for maintaining a reliable system.
- New market areas were established that were inconsistent with the boundaries of responsible operating entities and/or the regional councils responsible for reliability standards and enforcement. For example, the PJM and PJM West marketing area stretches across three reliability councils, at least three ISO/RTO-type organizations, and numerous control areas.
- An increase in system and decision making complexity, with more opportunities for delay and the likelihood of “watering down” decisions to the lowest common denominator. On the day of the August 14, 2003 blackout, MISO had neither the authority nor technical means to operate a generation and transmission grid in the region. Since formal spot-markets had not been established, a large number of bi-lateral contract trades originated with IPPs, complicating system operations (Rosen 2003). These IPPs had little incentive to provide needed reactive power on the day of the blackout.

⁶ Ownership and control of the transmission assets of the subsidiary electric utilities of First Energy were transferred to American Transmission Systems (ATSI), a subsidiary of First Energy and the first electric transmission subsidiary of an investor-owned utility in the U.S. Effective October 1, 2003, ATSI became part of the Midwest ISO through GridAmerica (a subsidiary of National Grid). GridAmerica is an independent transmission company within the Midwest ISO. With this transaction, ATSI’s control of those functions and activities were to be performed by the Midwest ISO and GridAmerica.

Increases in Complexity

The changes described above have created a more complicated and compartmentalized industry structure than was the case in the past. One example of the increased complication is the extraordinary increase in the membership of three “old line” power pools. The New York Independent System Operator (NYISO) 2004 *Annual Report* cites 245 “market participants” significantly more than the eight members that made up NYPP prior to restructuring (NYISO 2004). Each of these 245 market participants can make decisions about buying and selling electric power that affect the transmission system in New York and in other regions. In 1993, PJM had 10 members and served 23 million people in five states and the District of Columbia (PJM). Today, PJM has more than 350 members and operates in 13 states and the District of Columbia. ISO New England now has 237 market organizations, 150 of which are members of the Participants’ Committee (ISO New England). The complexity of the decision-making process has increased on the same scale in other regions of the country. There have not been significant changes since the 2003 blackout.

In addition to an absolute increase in the number of participants, the inter-relationships between and among the participants have changed. No longer are decisions made by a relatively small number of non-competing organizations; today, decisions are made by a large number of entities, most of which are competitors and each of which has more interest in profit than in bulk-power-system reliability. Procedural rules established between and among the various parties are no longer matters of overall corporate policy, but rather of contractual arrangements based on the parties’ financial self-interest.

In sum, the complexity of planning and operating the electric power system has significantly increased with the growth in the number of participants whose decisions affect the overall system. It has further increased because the objective of many of these organizations is short-term profits rather than long-term reliability (Richardson 2004).

Lessons Learned from Analyses of the August 2003 Blackout

For an overview of lessons learned from analysis of the 2003 blackout, we examine reviews of major blackouts in the past as well as the reports by DOE and NERC on the 2003 blackout.

Past Blackout Reviews

Following the August 14, 2003 blackout, a number of reviews were conducted, the most visible of which was by DOE and the Canadian government. Separate reports were prepared by NERC; by ECAR, MAAC, and NPCC; by the NY, New England and PJM ISOs; and by state regulatory commissions. Many of these documents focused narrowly on technical issues. However, the DOE/Canadian and NERC reports raise issues that could and should have been explored more deeply to determine how the complicated organizational structure of the current “deregulated” industry, with its heightened focus on commercial concerns, might have contributed to the problems that led to the blackout. Our approach is to highlight some of the conclusions/recommendations of these reports and to raise follow-up questions that have not been addressed.

The DOE Report

The following material is excerpted from the *Final Report on the August 14, 2003 Blackout in the United States and Canada - Causes and Recommendations - April 2004*; it by no means comprises all the material covered. The inserted questions are raised by the authors of this report.

Chapter 3: Causes of the Blackout and Violations of NERC Standards

Group 2: Inadequate situational awareness at FirstEnergy (FE). FE did not recognize or understand the deteriorating condition of its system.

Violations (Identified by NERC):

- **Violation 7:** FE’s operational monitoring equipment was not adequate to alert FE’s operators regarding important deviations in operating conditions and the need for corrective action as required by NERC Policy 4, Section A, Requirement 5.

Other Problems:

- FE’s operational monitoring equipment was not adequate to provide a means for its operators to evaluate the effects of the loss of significant transmission or generation facilities as required by NERC Policy 4, Section A, Requirement 4.
- FE’s operations personnel were not provided sufficient operations information and analysis tools as required by NERC Policy 5, Section C, Requirement 3.

- FE's operations personnel were not adequately trained to maintain reliable operation under emergency conditions as required by NERC Policy 8, Section 1 (DOE 2004, p. 19).

In the aggregate, the above problems raise the question of why adequate equipment, information and training were not provided.

Group 4: Failure of the interconnected grid's reliability organizations to provide effective diagnostic support.

Violations (Identified by NERC):

- **Violation 5:** MISO was using non-real-time data to support real-time operations, in violation of NERC Policy 9, Appendix D, Section A, Criteria 5.2.
- **Violation 6:** PJM and MISO as reliability coordinators lacked procedures or guidelines between their respective organizations regarding the coordination of actions to address an operating security limit violation observed by one of them in the other's area due to a contingency near their common boundary, as required by Policy 9, Appendix C. **Note:** Policy 9 lacks specifics on what constitutes coordinated procedures and training.

Other Problems:

- MISO did not have adequate monitoring capability to fulfill its reliability coordinator responsibilities as required by NERC Policy 9, Appendix D, Section A.
- American Electric Power (AEP) and PJM attempted to use the transmission loading relief (TLR) process to address transmission power flows without recognizing that a TLR would not solve the problem (DOE 2004, p. 20).

Why weren't real time data used? Was there consideration given to its use and, if so, why was the decision made not to use it? When MISO was established and approved, why wasn't this most basic function of an ISO in place? What instructions/directions were given to the operators when trade-offs between reliability and commerce occurred?

Institutional Issues

2. NERC and the industry's reliability community were aware of the lack of specificity and detailing some standards, including definitions of Operating Security Limits, definition of planned outages, and delegation of Reliability Coordinator functions to control areas, but they moved slowly to address these problems effectively (DOE 2004, p. 21).

What impediments does the new stakeholder process place in the path of the industry's reliability community when it tries to move effectively and expeditiously?

The NERC Reports

NERC in its report "*August 14, 2003 Blackout: NERC Actions to Prevent and Mitigate the Impacts of Future Cascading Blackouts – February 10, 2004*" approved 14 recommendations for corrective action. Included are the following directives to MISO:

B. Corrective Actions to Be Completed by MISO

MISO shall complete the following corrective actions no later than June 30, 2004.

1. Reliability Tools. MISO shall fully implement and test its topology processor to provide its operating personnel real-time view of the system status for all transmission lines operating and all generating units within its system, and all critical transmission lines and generating units in neighboring systems. Alarms should be provided for operators for all critical transmission line outages. MISO shall establish a means of exchanging outage information with its members and neighboring systems such that the MISO state estimation has accurate and timely information to perform as designed. MISO shall fully implement and test its state estimation and real-time contingency analysis tools to ensure they can operate reliably no less than every ten minutes. MISO shall provide backup capability for all functions critical to reliability.

2. Visualization Tools. MISO shall provide its operating personnel tools to quickly visualize system status and failures of key lines,

generators or equipment. The visualization shall include a high level voltage profile of the systems at least within the MISO footprint.

3. Training. Prior to June 30, 2004 MISO shall meet the operator training criteria stated in NERC Recommendation 6.

4. Communications. MISO shall reevaluate and improve its communications protocols and procedures with operational support personnel within MISO, its operating members, and its neighboring control areas and reliability coordinators.

5. Operating Agreements. MISO shall reevaluate its operating agreements with member entities to verify its authority to address operating issues, including voltage and reactive management, voltage scheduling, the deployment and redispatch of real and reactive reserves for emergency response, and the authority to direct actions during system emergencies, including shedding load (NERC 2004).

Collectively, these directives raise the question of why approval was given by FERC for MISO to become “operational” in the first place if so many basic operational issues have not been resolved.

The following italicized text was excerpted from NERC’s *“Technical Analysis of the August 14, 2003, Blackout: What Happened, Why, and What Did we Learn? – Report to the NERC Board of Trustees by the NERC Steering Group July 13, 2004”*.

The first page of the July NERC report states that “... the NERC investigation did not address regulatory, economic, market structure or policy issues” related to the blackout (NERC 2004a). However, under the section titled “Causal Analysis Results”, a tantalizing statement is made that reinforces our view that additional investigation is warranted (emphasis added).

The causes of the blackout described here did not result from inanimate events, such as ‘the alarm processor failed’ or ‘a tree contacted a power line.’ Rather, the causes of the blackout were rooted in deficiencies resulting from decisions, actions, and the failure to act of the individuals, groups, and organizations involved. These causes were preventable prior to August 14 and are correctable. Simply put — blaming a tree for contacting a line serves no useful purpose. The responsibility lies with the organizations

and persons charged with establishing and implementing an effective vegetation management program to maintain safe clearances between vegetation and energized conductors.

Each cause identified here was verified to have existed on August 14 prior to the blackout. Each cause was also determined to be both a necessary condition to the blackout occurring and, in conjunction with the other causes, sufficient to cause the blackout. In other words, each cause was a direct link in the causal chain leading to the blackout and the absence of any one of these causes could have broken that chain and prevented the blackout. This definition distinguishes causes as a subset of a broader category of identified deficiencies. Other deficiencies are noted in the next section; they may have been contributing factors leading to the blackout or may present serious reliability concerns completely unrelated to the blackout, but they were not deemed by the investigators to be direct causes of the blackout. They are still important; however, because they might have caused a blackout under a different set of circumstances (NERC 2004a, p. 94-95).

The following italicized sections are some of the General Conclusions also from page 94 of the NERC report.

- Reliability and control areas have adopted differing interpretations of the functions, responsibilities, authorities, and capabilities needed to operate a reliable power system.
- Deficiencies identified in studies of prior large-scale blackouts were repeated, including deficiencies in vegetation management, operator training, and tools to help operators better visualize system conditions (NERC 2004a, p.94).

We believe the following questions need to be addressed:

- The reliability coordinator function is relatively new (post restructuring). Why was it approved with such apparent weaknesses in its mission?
- What are the reasons for the inattention to these prior problems?

The following quotations come from page 101 of the NERC report, in the section entitled "Summary of Other Deficiencies in the Blackout Investigation":

22. Operating entities and reliability coordinators demonstrated an over-reliance on the administrative levels of the [transmission loading relief] TLR procedure to remove contingency and actual overloads, when emergency redispatch of other emergency actions were necessary. TLR is a market based congestion relief procedure and is not intended for removing an actual violation in real time (NERC 2004a, p. 101).

This observation raises the question of what managerial directions/guidance/instructions operators had been given vis-à-vis the relative importance of reliability and the market.

NERC's technical analysis of the August 14 blackout leads it to fully concur with the Task Force Interim Report regarding the direct causes of the blackout. The report stated that the principal causes of the blackout were that FE did not maintain situational awareness of conditions on its power system and did not adequately manage tree growth in its transmission rights-of-way. Contributing factors included ineffective diagnostic support provided by MISO as the reliability coordinator for FE and ineffective communications between MISO and PJM (NERC 2004a).

Why was MISO authorized by FERC if MISO was unable to provide effective diagnostic support, or if there were ineffective communications capabilities between MISO and PJM?

The remaining sections of this report attempt, to the extent feasible, to answer the questions raised above and to explain how restructuring caused the blackout, as well as an overall national decline in the reliability of electric power systems.

Change in Focus from Coordination to Competition

To understand how industry restructuring has led to a change in focus from coordination to competition, we summarize the coordination procedures of the past (regulated) industry and the changes that have resulted from deregulation.

Prior Coordination Procedures

Electric power systems require investments in major facilities typically costing from tens of millions to billions of dollars. These facilities have long lead times, requiring many years from start to completion, and often remain in service for up to 40 years.

Regulation provided for the return of the investment (depreciation) and the return on the investment (earnings) over the facilities' lifetimes.

Electricity systems were interconnected to take advantage of diversity in times of peak use, equipment outages and emergencies. The industry's focus was on reliability and long-term cost minimization. In that environment, a high degree of cooperation developed among those involved in owning, managing, planning, and operating electric power systems (IEEE 1993). This level of coordination and cooperation was accelerated in the years following the November 9, 1965 blackout.

Changes Caused by Restructuring

With deregulation and restructuring, the emphasis shifted from technical knowledge and competence to financial and marketing knowledge. Economic theory replaced engineering fact. The new managers are driven by the desire for "immediate profit." This has sometimes led to conflicts between marketers focused on profits and system operators responsible for reliability, and disputes have been arbitrated by top management.⁷

In brief, restructuring fostered policies that involved increased reliability risk taking in order to improve profits.

Expenditure Reductions to Improve Profits

Deregulation has resulted in reductions in expenditures on transmission facilities, maintenance, and personnel in the industry.

Reductions in Transmission Additions and Maintenance

There has been a 25 percent reduction in expenses for maintenance of power-system facilities⁸ (including but not limited to tree trimming), and in personnel (including operating personnel). In many companies, the time between routine maintenance schedules has more than doubled since deregulation (CECA 2005, Fig. 6, p. 33; Hunter 2000). Between 1990 and 2000, transmission investment fell at a rate of about \$50 million a year (CECA 2005, Fig. 3, p. 28).

⁷ This is evidenced by August 14, 2003 recordings of discussions between system operators, who wished to reduce power transfers, and marketers, who saw this as a threat to their profitability.

⁸ "Keeping the Power Flowing", 2005, Consumer Energy Council of America, Jan. (Fig. 6, p. 33).

Reductions in Personnel

The labor force at investor-owned utilities decreased from 480,000 to 350,000 between 1990 and 1999. U.S. Department of Labor data show that from 1999 to 2000 the numbers of utility employees working in power generation dropped from 350,000 to 280,000, and in transmission and distribution from 196,000 to 156,000, while electricity consumption continued to increase. Among the consequences were drastic reductions in training. At a FERC Technical Conference in Philadelphia, one system operator observed, "We have downsized quite a bit in our operating staff.... There is not a whole lot of time left for training."⁹ Many systems had no operator training programs, relying solely upon "on-the-job" experience. An independent European analysis has concluded that personnel reductions played an important part in recent blackouts there (EPSU 2003).

Changes in Technical Qualification of Those Managing Electric Power Organizations in Government and Industry

During the past 15 years there have been major shifts in the qualifications, experience, and knowledge required of those who control electric power policy and manage electric power activities.^{10, 11}

Past experience has shown that technical standards and procedures are much less important than the qualifications of the individuals who apply and enforce those standards and procedures. Nonetheless, in response to the new preeminence of market concerns, appointments to key industry regulatory and reliability organizations have increasingly downplayed technical knowledge and experience (Florman 1976). Many appointees to key electric energy policy positions, such as FERC Commissioners, show a complete lack of the experience relevant for their positions, or are beholden to certain segments of the industry (Barranco 2005).

⁹ Transcript-Panel 1, DOE Technical Conference on Blackout, Comments by Scott Moore, Philadelphia, Dec. 1, 2003.

¹⁰Over the years the experience of the majority of the industry executives has shifted from the technical to the financial and political. This is evidenced by changes in the membership on the Edison Electric Institute Board of Directors.

¹¹ The control of NERC has shifted over the past 15 years from those with technical backgrounds to stakeholders, most of whom have financial or political backgrounds. This is evidenced by changes in the NERC Board of Trustees.

Failure to Pass on Past Knowledge

Deregulation has led to a failure to transfer knowledge gained from past blackouts even though such knowledge could help prevent, or accelerate recovery from, future outages. This lack of knowledge transfer contributed to the 2003 blackout. We delineate the failure in knowledge transfer by reviewing investigations of past blackouts as well as the 2003 blackout.

Investigations of Past Blackouts

Between 1965 and 1977 there were three major blackouts affecting the eastern U.S. In 1978 a major blackout shut down all of France, an outage in scope close to the size of the August 14, 2003 blackout. Reviews of the 1965 northeastern U.S. and 1967 PJM blackouts led to the realization that extensive regional coordination of planning and operations was required to improve reliability.

Other lessons were learned from reviews of prior blackouts, e.g., the need to make certain that relay settings and transmission ratings were consistent and communicated to operating personnel (Northeast 1965), the need for “black start” capability (Northeast 1965), the vital need for an Energy Management System (EMS) to analyze potential problems (PJM 1967), the need for improved system restoration procedures (Northeast 1965, PJM 1967, Con Edison 1977), the need for adequate communication within and between control areas (Con Edison 1977), the need for adequate reactive supply (France 1978), and the need to make certain that line clearances on rights of way are maintained (West Coast 1996).

Following the blackouts mentioned above, many technical reports and papers were prepared, presentations were made at various public and technical committee meetings, and magazine and newspaper stories were published. Some of the lessons were specifically addressed in reliability council documents. However, these lessons have been ignored by the new, post-deregulation policy makers in today’s electric power industry. The DOE report on the blackout identifies these failures to transfer lessons learned from past blackouts as an important contributor to the August 2003 blackout.

The head of the DOE’s Office of Transmission and Distribution¹² commented that the restoration of power after the August 14th blackout in about 2½ days was a remarkable achievement. This was a prime example of two of our observations: an

¹² Recently changed to Office of Electricity Delivery and Energy Reliability.

especially uninformed regulator and the failure to pass on past knowledge. Almost 40 years earlier (November 1965), a system almost as large was completely restored in 13 hours. Following the blackout of all of France in 1978, the entire system was restored in four hours! Understanding how and why these restorations were accomplished is important knowledge, but was totally ignored by policy makers after August 14, 2003 – even though a three-volume report on the 1965 blackout was published by the U.S. government (one of this paper’s authors having served on the study group) and a report on the 1978 French Blackout (written by another of this paper’s authors on commission from the DOE).

Investigation of August 14, Blackout

The effect of the lack of technical competence on reliability and the August 14th blackout can be illustrated by a few examples:

1. FERC had approved the operation of the Midwest Independent System Operator (MISO), stretching across all or parts of three reliability councils. While FERC’s purpose was to facilitate market procedures, no analysis of the technical adequacy of MISO was attempted. There was no appraisal of whether MISO was prepared to assume operating responsibilities, whether the MISO control center was complete, and whether its operators were properly trained or qualified. In April 2003, MISO prepared its “Regional Transmission Organization (RTO) Reliability Plan.” It was vital that the procedures involved to coordinate MISO’s operations with existing reliability councils and security coordinators be carefully reviewed. Quoting from the DOE Interim Blackout Report:

Before approving MISO, FERC had asked NERC for a formal assessment of whether reliability could be maintained under the arrangements proposed by MSIO and PJM. NERC replied affirmatively but provisionally. NERC conducted audits in November and December of 2002 of the MISO and PJM reliability plans, and some of the recommendations are still being addressed. The adequacy of the plans and whether the plans were being implemented are factors in NERC’s on-going investigation (DOE 2004a.)

Even though the plans had not been deemed adequate, FERC approved the operation of MISO.

2. The chairman of FERC recently created a new department to address reliability matters, and assume national control of reliability standards and their enforcement. Additional engineers were hired for this purpose. The new staffers will work in the

Office of Markets, Tariffs, and Rates, under the management of those responsible for enhancing market procedures. The creation of this department is a recognition of past FERC failures, but the oversight of the department's work by personnel whose focus is to enhance markets demonstrates FERC's inability to understand the problem.

3. The government's blackout investigation is another example of the failure to allow technically competent advisors to contribute. The government carefully selected personnel and orchestrated the investigation's limited content (Smith 2003). The government controlled the writing of the report, the public hearings, and workshops conducted after the blackout. Technically competent participants were given bare minimum opportunities to comment. The government even required those involved in the investigation to sign confidentiality agreements, an action unprecedented in the history of electric power in the U.S. By contrast, following the 1965 blackout, Joseph C. Swidler, then chairman of the Federal Power Commission (FERC's predecessor), was instructed by President Lyndon Johnson to have the nation's best engineering talent available to supervise the investigation – and that is exactly what happened (Univ. of Tenn. 2002). The U.S.- Canada Power Outage Task Force and the Electric System Working Group for the August 2003 blackout were composed almost entirely of individuals either in federal or state regulatory positions. Few appear to have had any technical experience in planning or operating a power company. The NERC steering and working groups were staffed by highly qualified technical people; however, these participants did not oversee preparation of the study's report which was a DOE staff effort.

Departure of Key Personnel

Often essential knowledge is held by one individual or a very few teams and cannot be passed on except through direct contact, i.e., a "doctor-intern" type relationship. Programs that encouraged early retirement in electric power companies facilitated the departure of personnel with extensive experience causing a breakdown in the essential transfer of knowledge (Hyklo 2005). NERC's approach of writing voluminous procedures is not sufficient to correct this problem. As we have noted, the best procedures are only as good as the experience and expertise of the parties applying them.

Summary

The stage was set for the events of the 2003 blackout by changes in the structure of the electric power industry (Casazza 1998).¹³ The federal government, mostly through FERC, had mandated untried and inappropriate structural changes. It established new rules and procedures that facilitated bad behavior (e.g., Enron), with no analyses of the potential effect on reliability (Whightman 2005; Lerner 2004). In a survey, more than half of the utility executives polled (along with many others) expressed the belief that industry restructuring has caused a decline in reliability (Gale 2004). Only participants with no technical background argued that market forces could somehow produce good engineering designs and operations. In the wake of these failures, “spin” has, perhaps predictably, replaced substance, for example:

- NERC’s publication of the so-called “Version 0” of its reliability standards was promoted to the press and public as a direct response to the August 14, 2003 blackout – when, in fact, it was nothing more than the restatement (in a somewhat different format) of the same reliability standards NERC had been using for more than a decade.
- NERC continues to deny that changes proposed to its transfer capability definitions are in effect a lowering, and watering down, of its standards. Yet this is demonstrably so in the view of anyone familiar with the subject.¹⁴ Unless this trend is reversed, more blackouts will happen.

The recently proposed Reliability First Corp., which would merge the regional councils -- MAAC, ECAR, Mid-Atlantic Interconnected Network (MAIN), and possibly Midwest Reliability Organization (MRO) -- into a single new reliability council, is being presented as a “fix” to some of the problems that led to the August 14, 2003 blackout. But this merger in no way addresses the important question of the host of geo-electrically small control areas in the midwest, which contributed significantly to the 2003 blackout. Had Reliability First Corp., as now proposed, been in existence on August 14, 2003, nothing would have been different. This is a solution searching for a problem, spin rather than substance.

¹³ DOE POST study, IBEW testimony.

¹⁴ Specific examples are past revisions of the 10- and 30-minute reserve requirement to 15 and 105 minutes, and proposed revisions to NERC Standard 600 to eliminate provision for the loss of both circuits on a double-circuit tower line.

Recommendations¹⁵

The authors have been asked to provide recommendations, a difficult assignment. In the massive effort to “deregulate” and “restructure” the electric power industry, the Laws of Physics were ignored, replaced by a blind conviction that the Laws of Economics could provide all things – including a reliable system. Unfortunately, this has been proven to be a tragic mistake. The problem with correction, however, is that a fundamentalist market philosophy has so permeated the entire industry, from the Federal Government and its regulatory officials to the industry’s own organizations, that to undo the damage will likely take an effort well beyond a few simple recommendations. The problem cannot easily be fixed since the problem is an innate attitude or belief system, not an error or two in procedures or protocols. An indication of this is the fact that, despite such evidence as the California Meltdown, unprecedented price spikes, the criminal actions of Enron and others, and the most devastating blackout in our history, policy makers still steadfastly deny that deregulation and restructuring had anything at all to do with any of it. Sociologists call this “cognitive dissonance.”

Recognizing this difficulty, there are a number of steps that could be taken to start the nation on its difficult corrective path:

- Before approving any new ISO/RTOs, ensure and demonstrate that the entity is fully functional.
- Investigate and recommend guidelines for the geo-electrical characteristics of control areas.
- Require NERC to roll back the reductions in reliability standards implemented since 1998.
- Prohibit NERC from implementing any further reductions in reliability standards.

¹⁵ These recommendations were prepared prior to recent Congressional action that made making reliability standards mandatory. They have since been reviewed and remain unchanged, since the problem is not whether the process is mandatory, but how strong the standards are, how our recommendations are implemented, and how competent those implementing them are. In any case, since the Energy Policy Act of 2005 does not address the underlying causes of the 2003 blackout, it will have no effect in improving the reliability of the bulk power system.

- Permit any state or reliability entity to mandate more stringent reliability standards than NERC's. In other words, make sure that NERC standards are a floor, but not a ceiling.
- Before implementing a new market design, ensure and demonstrate that the design's impacts on the reliable operation of the power system have been fully evaluated.
- To make markets work more efficiently and effectively, emphasize in policy standards the need to foster cooperation between organizations.
- Develop standards for technical qualifications required for key government and industry positions, including those responsible for establishing electric power policies, and for management, design and operation of the transmission grid.
- Require that appointments to FERC and the new DOE Office of Electricity of Delivery and Energy Reliability, and to the NERC Board and senior management positions, have demonstrated expertise and experience in electric power and are vetted by the National Academy of Engineers, with input from the Institute of Electrical and Electronic Engineers (IEEE), Edison Electric Institute (EII), the American Public Power Association (APPA) and National Rural Electric Cooperative Association (NRECA).
- Mandate that DOE, in consultation with FERC, NARUC, and NERC, undertake a biannual "National Power Survey" modeled after the 1964 survey. This survey should give emphasis to reliability risks, including such incidents as the loss of major gas pipelines, as well as economic constraints (Clark 2004).
- Investigate and develop new programs for encouraging and improving the transfer of technical experience and expertise in the electric power industry and universities; such efforts could be enhanced by utilizing experienced retired engineers from the electric power industry.
- Investigate the effects that extensive labor reductions have had on overall national reliability, and on the ability to cope with national disasters and acts of terrorism.
- Require that marketing areas and reliability council areas be consistent.

- Support the reporting and exchanging of information related to system reliability. (Concerns exist about the consistency of some information, and the availability of data to the entire electric power industry.) The Federal Government could play an important role in enhancing the definition, collection and sharing of information.
- When adjusting generation because of transmission economic constraints, insure that such adjustments minimize reliability risks.
- Investigate and monitor reductions of maintenance expenditures as indicated in reports to FERC as a part of FERC's reliability monitoring function.

Additional references can be obtained at the following web sites:

www.PEST-03.org

www.ameredinst.org

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The Blackout of 2003 and its Connection to Open Access

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Summary

While moving toward open transmission access and market competition, the U.S. electricity industry allowed confusion to develop regarding the actions necessary to maintain the reliability of the power grid and the entities responsible for those actions. This confusion was at the root of the 2003 blackout and, despite much work, continues to threaten electricity system reliability.

Relationship among Open Access, Market Competition, and Reliability

The relationship among the establishment of open access to transmission, competitive markets¹, and the reliability problems of the electricity system has both a physical and a structural aspect.

The physical aspect is based in the dynamics and operational requirements of the electricity network itself. Two physical issues that affect reliability and are often discussed but seldom resolved are:

- 1) that the existing transmission network was not designed and built to support regional competitive wholesale markets, and the growth of the regional market placed heavy stress on the transmission grid and made the grid harder to operate, and
- 2) that, due to the interconnected nature of the grid, transmission operators within each interconnection are essentially hostages to one other; if one fails to do the right thing, all others suffer the consequences.

These two physical elements of the grid's functioning mean that operation of the transmission network in open-access mode is more demanding and costly and requires more attention and skill than was the case before the advent of open access. The second and more interesting aspect of the relationship among open access, market competition, and system reliability is structural. To understand this

¹ Open access is related to the need for the transmission grid to support competitive wholesale electricity markets, which the U.S. Congress mandated in the Energy Policy Act of 1992.

relationship, it is instructive to recall the sequence of the most significant events related to the establishment of open access.²

During most of the 20th century, utilities operated under a slowly evolving understanding that is frequently referred to as the regulatory compact. This compact assured a balance between obligations and rights on the side of the companies and between costs and benefits on the side of the consumers. Local (i.e., state) regulators were the arbiters of the compact and the balances.

A similar compact ruled the rights/obligations and costs/benefits balance among the control area utilities within each interconnection. Transmission owners had the sole right to use their systems to move energy. They could trade only with other utilities to which they were directly connected via a contract path, which was established by the literal, physical network connection between them.³ Transmission-owning utilities shared the gains and the pains of being interconnected. Although this mutual support helped reduce the costs of reliability (through lower capacity margins, for example) and allowed some sharing of generation costs, being interconnected also created loop flows that significantly increased the costs of running a control area⁴ and the risks of cascading failures.

In general, the regulatory compact worked in the following manner: the utilities, as regulated monopolies, assumed the obligation to build as necessary to meet the needs of their customers in a rational, cost-effective fashion. In turn, they had monopoly rights within their territories, and regulators let them earn an adequate return on their investments. As a result of the compact, customers were to get reliable service at prices that reflected the benefits of scale.

² Although federal, cooperative, public-power, and Canadian utilities own and operate considerable transmission assets, the U.S. investor-owned utilities own and operate the bulk of the network in the U.S., so the historical review in this section focuses on their perspective. Ultimately, the basic issues affect all transmission owners alike.

³ The contract path was no myth; it was a handy vehicle to describe commercial rights in the interconnected world. The contract path was a path for rights and money, not electrons.

⁴ The relevant costs of operating a control area were those related to the obligation to provide generation capacity and energy to support network operation, including the costs of:

- reserves (planning and operation)
- energy from operating reserves during system emergencies, especially at times of low system frequency regardless of market price (this energy was returned in kind, usually during cheaper, low-load periods)
- control area losses
- generation redispatch to prevent transmission overloads regardless of cause (service to own load or actions of neighboring utility)

Control area costs also included those related to each utility's obligation to build its share of transmission assets to maintain an adequate network for all participants. In most parts of the country, the costs of operating a control area were proportional to the size of the utility, and state regulators considered these to be prudent and passed them on to the customers.

Not everyone benefited equally from the regulatory status quo. Smaller utilities that were mainly load-serving entities operating within someone else's control area had little leverage when it came to negotiating with the transmission owners. In addition, existing utilities were perceived as having little incentive to invest in the development of new, lower-cost generation.

The successive steps taken to establish competition in wholesale electricity markets upset the regulatory compacts and balances.⁵ The resulting imbalances are the root of the electricity industry's difficulties in addressing the reliability problems that led to the blackout.

In 1978, the U.S. Congress passed the Public Utility Regulatory Policy Act (PURPA) to promote utilization of generation technology that promised greater fuel diversity, efficiency, and, it was hoped, lower costs. This legislation was the first breach in the regulatory compact. From the perspective of the established utilities, the developer of a PURPA-qualified plant had the rights (to sell energy to the utility at avoided costs as determined by the state commissions) but none of the obligations (no limitation on where to do business, no obligation to serve, and no obligation for any of the costs of system reliability) of a utility. Utilities hosting a PURPA generator also had to risk arousing the ire of their customers by seeking rate increases to accommodate the costs of the PURPA contracts while losing an opportunity to increase their own investments and earnings.

The establishment of the first open-access tariffs following the issuance of Federal Energy Regulatory Commission (FERC) Order 888 in 1996 created an even more dramatic breach in the regulatory compact. New industry participants – energy marketers – gained the right to use the grid at embedded-cost-based rates. Utilities were required to provide this service under the same conditions that governed service to their native loads.

Within a short time after open-access tariffs were enacted, the number and size of wholesale transactions boomed. The increase was caused not only by energy marketers but also by the utilities themselves trading power regionally to get lower energy costs for their native loads and to maximize the value of their generation assets. Transmission service was sold mostly on a contract-path, point-to-point basis. The resulting loop flows soon made it very difficult for control area operators to control their systems and created congestion and reliability problems that had never

⁵ This includes the passing of PURPA and the sequence of steps that have been taken by the Federal Energy Regulatory Commission (FERC) and state regulators to open access and deregulate generation.

been seen before. Many portions of the network that had been deemed adequate through 1996 by the North American Electric Reliability Council (NERC) regional councils soon became marginally adequate and even inadequate.

Soon, the control room operators in most parts of the interconnection were facing, on a weekly and even daily basis, system emergency conditions that they had seldom seen before the implementation of FERC Order 888. The industry responded by establishing Regional Reliability Coordinators and creating Transmission Loading Relief (TLR) procedures to deal with the frequent threats of line overloading.

From the perspective of transmission-owning utilities, the increase in the numbers of transactions and system emergencies increased the costs of maintaining system reliability (adequacy and security) while the bulk of the financial benefits of these changes went to the ever-growing number of third parties that did not bear the majority of the costs. This was a definite upset of the traditional cost-benefit balance of utility interconnections.

The establishment of marketing groups and separate generation companies within utilities, along with retail competition and rate freezes, exacerbated the confusion in the industry. At this point, the basic question “who is responsible for system reliability?” began to get some very vague responses.⁶

The attention of the industry – utilities, marketers, regulators and customers – was focused on ensuring fair access to transmission capacity and promoting robust competition in the energy markets, rather than on reliability. In 2001, NERC elected a fully independent board of trustees, and the utility Chief Executive Officers (CEOs) who had traditionally held those board positions backed away from direct involvement with NERC and the regional councils. These CEOs turned their attention to the business challenges posed by the new industry trends.

In short, while the work within the control centers was becoming ever more complicated and stressful, the attention of regulators, customers, and utility management was focused on the market and its needs. The breakup of the old cost-benefit balances was not followed by a clear reallocation of reliability costs and responsibilities among the new set of participants. Rate freezes made it hard to justify the increasing costs of running control areas and the construction of new transmission facilities. Utility marketing departments had a very difficult time

⁶ In some cases, the answer was “transmission operators”, in others “marketers running generation”. Even “the market” was supposed to be accountable for reliability.

accepting the need to comply with NERC criteria that required energy-load imbalances to be promptly restored by either buying energy in the market, at thousands of dollars per megawatt hour if necessary, or dropping firm customer load. In addition to very high costs, the voluntary nature of NERC rules intensified the pressure to evade compliance.

As long-time utility executives have retired, bright young people have been promoted to take charge of transmission operations. However, because of the utility management's growing hands-off treatment of NERC and the regional councils, these new officers more often than not have had no exposure to NERC, the regional councils, or reliability rules. Consequently, they are ill prepared to support the activities of control room operators.

The few well-known and most egregious incidents of bad operation obscured the fact that the rules and network were being challenged on a daily basis. Not surprisingly, the number of TLR events needed to assure the integrity of the network grew steadily, each incident testing the ability of operators and the limits of the network. The specific conditions that led to the blackout of 2003 were only one more bad day in a sequence of steadily worsening days in network operations. The blackout could have happened earlier or later, there or elsewhere.

Conclusions

There have been significant benefits from the introduction of competition in the wholesale electricity market, and the opening of the transmission network to all participants, under similar terms and conditions to those that have been imposed, makes sense. What has been wrong is the attempt to reorganize a very complicated industry one piece at the time without ensuring an adequate set of balances between risks and rewards, duties and rights, regulated and unregulated industry participants.

In other words, reliability problems and threats have not increased as a result of the policies themselves, i.e., the introduction of competitive wholesale markets or new participants in the generation and load-serving parts of the industry; reliability problems have increased because of the way these new policies were implemented. The electricity industry (legislative and regulatory policy makers and industry executives) has allowed an intolerable level of confusion regarding reliability. It does not take much elaboration to trace the roots of the 2003 blackout to that confusion.

Clear Ideas – The Way Forward

Much work has been done in reaction to the 2003 blackout, and, while much has improved, much more work remains. The confusion is not as deep as in the days when Enron led the chorus against the old monopolies, but there is still confusion. The following recommendations can help us move forward to clarity:

1. Security comes first. Even though an inadequate system can be secure, an insecure system can never be adequate.
2. Transmission owner-operators are accountable for system security.
 - a. Only the owner-operators have the means to make the system secure in real time.
 - b. NERC, regional councils, FERC, and regional transmission organizations all have a role in system reliability. However, the public, customers, state regulators, and state governors must ultimately hold utility owner-operators accountable.
 - c. Network reliability is expensive but cheaper than the alternative.
3. NERC's control area concept is not workable anymore. Instead, there must be a logical and clear allocation of reliability functions among the participants in the electricity network.⁷ Costs and responsibilities must be allocated equitably among all participants in and users of the electric system.⁸
4. Reliability rules must be enforceable rather than voluntary. NERC and the regional councils must set enforceable minimum requirements for transmission operations and planning.⁹
5. Given the importance of their role in system security and their mutual interdependence, transmission owner-operators must commit to meet their NERC

⁷ NERC is already proceeding in this direction.

⁸ Who is going to pay for the new infrastructure? Consumers paid for the blackout, and consumers will pay for the infrastructure that is needed to support the market reliably. Let's face it: the most expensive transmission line is the one that isn't there when it is needed.

⁹ The energy bill recently (Aug. 8, 2005) signed by President Bush provides the legal authority needed to make the rules enforceable in the U.S. The implementation of this law in the U.S. and of similar provisions in Canada must now proceed promptly. It has been a long haul and we are not done yet!

and regional council obligations and, beyond that, to a joint effort of continual identification, sharing, and implementation of best practices.¹⁰

6. CEOs of transmission owning companies must re-engage by participating in the boards of NERC and the regional reliability councils. The participation of a few CEOs in these boards will not compromise their independence. It will, however, do a lot to assure effectiveness because the CEO board members will call the attention of the other utility CEOs.
7. NERC should require that all executives in charge of utility operations be certified. This step will not make them operators, but it will assure that executives are fully aware of the reliability rules and their companies' obligations. Then they will be able to support the activities of the control center operators.
8. Although transmission transfer capability is a market commodity, the transmission infrastructure itself is not.
 - a. Utilities bear responsibility for implementing energy policies at the federal and state levels. Open access and competition are only two aspects of those policies.
 - b. Significant transmission construction is needed to adequately support economic development and competitive regional wholesale markets. Transmission needs to be recognized as a public good, not a market good that must be offered by essentially monopoly transmission providers and must be planned and constructed not based on market signals, but instead based on long-term public policy (that policy includes the need to support a competitive electricity marketplace).
 - c. Adequacy, security, universal access to electricity service and support for local economic development are also significant features of federal and state policies that will not be reflected by the signals from the electricity market.

¹⁰ For this purpose, some among transmission owners-operators are discussing the development of a transmission operations best practices organization following the lead of nuclear operators and the practices of the Institute of Nuclear Power Operations. Best practices exceed the minimum requirements of NERC and regional council reliability rules.

Competitive Electric Power Markets and Grid Reliability: Something Has Changed During the Past Decade!

**Kellan Fluckiger, Executive Director
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Electricity – Can't Live Without It!

Electric power's contribution to modern life is unparalleled. Electric power is pervasive in our society, permeating every aspect of the economy and affecting our daily lives both in business and at home. We depend on extraordinarily high reliability in electricity service; interruptions are limited to no more than a few hours per year and have far-reaching consequences when they occur.

This dependence on electricity is starkly evident as we recall the blackout in the eastern part of North America in the summer of 2003. Although the costs are still being sorted out, they are estimated in the billions of dollars. The aftermath of the blackout is fervent activity by public commissions; regulatory bodies; and federal, provincial, and state agencies to identify appropriate actions to prevent such outages in the future.

Not only are we dependent on electricity, but customers' expectations of reliability have changed. Consumers are demanding very high quality power in their homes for electronics and at work for industrial processes. Some industries have indicated that the tolerances of their processes require fluctuations of no more than a few volts and frequency distortions of less than a cycle. Higher quality does not come without a cost. The question is: who should pay these higher costs, the individual customer or society as a whole?

Fundamental Changes

During the past few years, the way in which electricity is provided to customers in most jurisdictions has changed fundamentally. The changes do not speak to the physics of electricity or to how it is delivered in a physical sense, but they affect the institutions, pricing, reliability, and regulation of this essential service.

Previously, electricity was delivered by integrated electric utilities that directly served their customers and owned both generation and transmission. Restructuring has altered the rules that governed control, operation, ownership, and regulation of

the industry so that the traditional integrated utility has been disaggregated. Regions across North America have embraced a market philosophy for generation, wholesale power trading, and retail electricity services. Generation is controlled or owned and operated by private, non-regulated companies. Electric energy costs, instead of being set by regulators, are priced by market fundamentals. Transmission, however, remains regulated as a natural monopoly to ensure open, non-discriminatory access and to protect the public interest.

Key Issues

In order to understand the relationship of industry restructuring and reliability, we first need to understand how generation and transmission and the interconnected network have changed as a result of restructuring. In view of those changes, we can then address the roles of the key players, such as the Independent System Operators (ISOs) who can affect reliability, and the key considerations that affect transmission in particular.

A New View of Transmission

Transmission systems are no longer overhead pipelines to move a certain amount of electric power from generator A to load B. The transmission system now connects many components, including millions of commercial transactions, into a gigantic synchronized machine. There is a greater strain being placed on the system because of the increase in supply and demand. Growth in the digital economy has increased the demand for diversity and higher reliability.

The Electricity Market has Changed - Focus Used to be on Generation

The transition from a regulated-utility model to a competitive-market structure is complex. This is particularly true for electricity because of its physical properties; electricity is not storable, it moves at the speed of light, and it has no substitutes. Moreover, because of the integrated nature of electricity service, -- generators, transmission, distribution, wholesalers, and retailers are all engaged in delivering the product to customers.

A number of changes related to the competitive market have changed the way that generation decisions are made. First, wholesale electricity costs are no longer regulated; prices are now set by supply and demand in a market context. And, second, generation owners no longer have their historic obligation to serve. As private, non-regulated market competitors, they make decisions based on their

financial interest and must compete in the private capital market like any other high-cost, capital-intensive, long-lead-time investment.

In a competitive market, generation investment decisions are made based on future expectations of market performance. This means that the electricity market framework must provide signals that are predictable, understandable, and supportive of future investment in the electricity sector to underpin economic growth. Suppliers, too, need assurance that they can get their product to market, over a reliable transmission system, so they can have the opportunity to compete.

Finally, the framework for load must also be predictable and reflect market fundamentals. Existing and future load customers must be able to make reasonable predictions about price to make informed choices. Load must be assured it will have access to needed electricity supply, including the required levels of quality and reliability. The cost of unreliability to customers, especially industry, is very high. In light of all these issues, a new view of transmission is needed.

Access to Transmission

To support the new market structure, transmission must be readily available and open to all supply and load customers in a non-discriminatory manner with sufficient capacity to constrain neither load nor generation. Transmission remains a regulated monopoly and is the foundation for reliable service. Transmission is now also the facilitator of the competitive market. The cost of transmission must be evaluated not only in light of its contribution to reliability and cost effectiveness but also its contribution to a smoothly functioning competitive market.

The Inter-ties

Transmission development must recognize that each region is part of, and connected to, the rest of the North American electricity grid. Inter-ties are an essential part of a competitive market and a reliable electricity system, both as a means to import power when needed and to export surplus energy, ensuring that the competitive wholesale market functions effectively. Inter-ties are essential to a well-functioning market. The transmission policy and regulatory environment must facilitate open access to larger markets while ensuring that regional needs are met.

Transmission – The Neglected Partner

Transmission is the foundation for reliability and a competitive market. The role of transmission has been amplified by the change to a market-based framework. Therefore, the value of transmission has changed and must be understood in light of transmission's new, broader role.

The Question of Reliability

Today, there are more transactions, players, and variability in system conditions than in the past. Demand for energy has increased year by year as most jurisdictions continue to grow. Suppliers and customers continue to expect predictable service without disruption. Balancing supply with demand has become more challenging as market forces influence when and if a generating unit operates. There are numerous examples of the impact of market forces. One example is that some services provided by generation resources, like power system stabilizers and automatic voltage regulation, which were previously taken for granted, must now be specified and paid for through contracts and agreements. Reliability has become more complex. Today's transmission system must accommodate greater variability in power flows and system voltages than were true in the past. Energy is exchanged based on domestic and regional needs. All these factors increase the challenges of maintaining reliability of the transmission system.

Transmission Delivers Benefits

As the market facilitator, transmission facilitates new generation by providing non-discriminatory and efficient transport to the market. Transmission must be robust and adequate to allow for a fully competitive and functioning market, or customers will not receive the benefits of competition. For generation competition to deliver benefits to customers, every single megawatt of electricity must be able to reach the market. Stranded generation is not in the interest of the customer or the producer.

Congestion is Not a Good Thing

Transmission systems are vulnerable to periodic disruptions. Inadequate transmission creates bottlenecks that compromise reliability and undermine market efficiency. System constraints such as congestion foreclose, disrupt, and increase the cost of power delivery. Congestion on transmission systems creates "winners and losers" as some generators are unable to reach the market with their products. Congestion drives energy prices higher.

Lack of transmission investment is resulting in economic penalties: rising losses and constraints on more economic generators. When *any* congestion exists, even one megawatt, the cost for all energy in the market rises to the cost of the next megawatt that can be delivered. Transmission congestion is simply counterproductive to the interests of customers, and it costs money. Transmission congestion calls for action. Prevention is the cure for transmission congestion.

We've Gone "Short" on Transmission Investments

The timeline for transmission is getting longer, which is exactly opposite to what markets need. The lack of transmission investment has been recognized as being costly relative to the potential benefits it will yield. Whether the costs are assessed in terms of increased line losses, reduced market efficiency, or degradation in reliability, transmission investments still deliver substantial benefits. Customers bear the direct cost burden of congestion, both in the short term by paying higher energy prices and in the long term in the form of costs of deferring transmission additions. Customers also bear the indirect, substantial costs resulting from disturbances or outages. Paying to remediate congestion, instead of building new transmission, is wasteful and not in customers' long-term interest.

A Call to Build

We need to upgrade and make additions to the transmission system – fast. Everyone everywhere is late to the party. Throughout the world, electricity systems face similar decisions to upgrade their transmission to meet growing demand. The lack of investment in new transmission facilities has produced detrimental effects including major widespread service interruptions and substantial economic losses. The impacts of the U.S.-Canadian Eastern outage in the summer of 2003 are well known. Other substantial service interruptions have also recently taken place in Italy, Denmark, Sweden, and England. Timely planning and development of transmission are integral to maintain reliability and prevent congestion.

The Timing Gap

Transmission additions are "lumpy" by nature and take considerable time to plan and build. Because transmission typically takes longer to develop than generation, it is understandable that generation developers may be reluctant to invest if they believe adequate transmission is not in place. Therefore, the institutions responsible for transmission planning must look forward and make assumptions about load growth and generation development to ensure that a robust transmission system is in

place in a timely manner. A forward-thinking transmission policy will declare that it is in the public interest to take ownership of the timing difference between generation and transmission additions.

The electricity industry continues to evolve to find the right set of policies, regulations, economic structures, and incentives to spur the transmission investment that is so sorely needed to ensure system reliability and handle the level of demand and the market forces that will affect the grid of the 21st century.

The Planning View

The power system is a huge interconnected, synchronous machine; an operation in one area can be felt throughout the entire system. In order not to adversely affect our neighbors, we must move from the myopic regional planning approach to a view of the wider interconnection. This is not easy and may not have been a fully functional strategy in the past; however, if we are to move forward with reliable power systems, integrated planning for the overall interconnection is essential.

Putting Off Maintenance

In the competitive environment, companies must attend to the need to maintain their facilities as well as to their bottom lines. The practice of deferring necessary maintenance, such as vegetation management, as a way to generate short-term profit must end; a single tree can cause a blackout.

Advent of the Merchant Power Line

Merchant transmission is an offshoot from traditional transmission projects built by utilities and approved by regulators on a cost-plus, rate-of-return basis. Despite the urgent need for new transmission infrastructure, investment in merchant alternating-current (AC) projects has been slow to materialize. Frustrating the industry is the conundrum that building a new transmission line erodes the very spread that the line was intended to capture.

Other challenges include the uncertainty of regulatory processes and investment recovery as well as the unpredictability of flow patterns in the bulk power system. Changes to underlying checks and balances, such as coordinated operations and planning, which have in the past been the foundation for the reliable operations of regional transmission systems, have also added to the complexities.

In Alberta, a framework, through legislation, has been created to allow merchant transmission projects to be developed, primarily for import or export. These projects are to be considered on a case-by-case basis. Pricing for such projects would normally be paid by the project beneficiaries that are the exporters/importers. However, if residual benefits to the internal grid, such as increased reliability, are demonstrated, consumers may fund system upgrades in a manner consistent with the benefits.

What's the Answer?

The significantly larger number of energy transactions, more and more generation sources and congestion, and changing power flows that were never previously contemplated are evidence that competition has impacted reliability. The sheer volume of energy that the transmission system is being asked to accommodate has an impact. How can we reduce the risk of a blackout like the one in August 2003? The answer is to reinforce our transmission systems by building new and upgrading existing facilities and to improve the way we monitor, schedule, maintain, and operate the grid.

Roles, Responsibilities and Relationships of the Institutions – to the Market and for Reliability

The electric power industry must have in place effective institutions to address transmission's dual role of reliability and commercial market facilitation.

Guardian of Reliability

Although it is tasked with many important responsibilities, first and foremost the ISO/regional transmission organization (RTO) must be the guardian of reliability. This responsibility and authority for maintaining the reliability of the power system needs to be given to the ISO/RTO through legislation.

The ISO Plans

The ISO/RTO is also responsible for planning the transmission system, including creating or implementing criteria, standards, and rules to ensure system integrity and adequate supply to meet demand. In planning the transmission system, the ISO/RTO must respect the fact that jurisdictions are not isolated from each other and that they must, therefore, adhere to the relevant operating standards and policies that govern North America's interconnected electricity systems. These standards and policies apply to every aspect of the physical delivery of electricity.

Established by the North American Electric Reliability Council (NERC) and Regional Reliability Organizations (RROs), the standards are intended to keep the lights on everywhere in the interconnected grid without operational behaviours that are detrimental to others on the system. The real-time and interconnected nature of electricity systems absolutely requires adherence to these standards so that neighbouring systems do not adversely affect others as happened on August 14, 2003. It is patently obvious that mandatory reliability standards are required.

Planning Supports the Competitive Markets

ISO planning must also recognize the needs of the competitive market. Planning for a robust transmission system supports the competitive market in two important ways:

1. A robust transmission system facilitates development of new generation by allowing efficient transport of power to the market. Inadequate transmission is a deterrent to development of new generation. Investors want assurance they can get their product to market.
2. Robust transmission contributes to a level playing field. Non-discriminatory transmission access is fundamental to competitive generation. The transmission system should not determine “winners” or “losers.” All generators, including intermittent sources like wind, should have equal opportunity to compete in the market. Only an adequate, open, non-discriminatory transmission system can facilitate this objective.

ISO Operates Markets

In some cases the ISO is the operator of the competitive wholesale market. In this role, the ISO must be independent and unbiased for the market to function competitively in a fair and open manner. Non-discriminatory operation of the wholesale market is as important as non-discriminatory access to the transmission system. There is a nexus between a robust transmission system and the competitive generation marketplace that needs to be reflected in the duties of the ISO/RTO.

ISO Role in Standard Setting

The ISO/RTO must be a full participant in the development of new or amended reliability standards and must monitor compliance with reliability standards and submit reports to the appropriate agencies.

In practice, the ISO/RTO, transmission facility owners, and others are expected to work cooperatively with the RROs and NERC on setting reliability standards. It is essential that mandatory and enforceable reliability standards become a reality sooner rather than later. Legislators need to be encouraged at every opportunity to enact such standards. In the Western Interconnection, participants have voluntarily entered into a Reliability Management System (RMS) Agreement with the Western Electricity Coordinating Council (WECC) that includes a contractual commitment to abide by WECC reliability rules. This contract approach works well and should be championed as a model for other regions. The RMS can be modified to incorporate mandatory enforcement requirements.

Role of the Regulators

Changes to the electricity industry have altered the role of the regulator. In the former integrated utility environment, regulators were asked to review proposals for new investment, taking need for generation and transmission into account together. There are often trade-offs between generation and transmission investments. Accordingly, transmission was evaluated as a portion of the overall tariff to be charged to customers. In that environment, it was acceptable to trade off generation and transmission because ratepayer dollars were used for both investments. In the wake of electricity industry restructuring, regulators need base their evaluations on the new industry framework, in which generation and transmission investment decisions have been decoupled. Generation has become a business decision for private investors vying to compete in the new marketplace. A “need” assessment for new generation is now a thing of the past. Trade-offs between transmission and generation are, therefore, no longer appropriate. Market forces determine generation additions and investors assume the risk of these decisions.

Transmission needs to be evaluated by the regulators in a new light consistent with the changes in the electricity market. Transmission remains regulated as a natural monopoly to assure both reliability and efficiency. The transmission system functions as a single entity and needs to be managed and regulated in a highly coordinated manner to ensure balance of supply and demand at all times. Building competing sets of wires across the same regions would result in unnecessary and costly duplication. Transmission systems built as a patchwork of control and ownership will never operate as reliably and efficiently as desired.

Regulators Must Take a Long-Term View

A long-term perspective on transmission development is required. It is necessary for regulators to assess and evaluate proposals for new transmission taking into account transmission's role as reliability agent and market facilitator. Regulators must also have regard for how a transmission upgrade or expansion contributes to: improving system reliability, facilitating a robust competitive market, improving system efficiency, improving operational flexibility, maintaining options for long-term development of the transmission system, fostering a desirable investment climate, and providing transmission access to other jurisdictions.

Although regulators must consider cost, reliability and operational flexibility must also be carefully addressed. Transmission is now both the provider of reliability and the highway for electricity commerce. Therefore, evaluations of new transmission must consider these complementary objectives, taking a broad and forward-looking view. The absence of appropriate regulatory mechanisms for cost recovery has led to an underinvestment in transmission in most jurisdictions.

Role of the Policy Maker

It is incumbent on policy makers and governments to be clear about the role of the ISO/RTO in ensuring reliability and about how the ISO/RTO is to work with other institutions in fulfilling its mandate. Policy makers need to identify areas where the ISO/RTO role or responsibility is not clear and promptly enact legislation to resolve the lack of clarity.

Role of the Wire Owners

The wire owners, both transmission and distribution, have a responsibility and need to maintain their systems at a level that ensures safe, reliable, and economic delivery of electricity. This includes all aspects of operation, maintenance, construction, and practices for the assets under their control.

Working Together

The industry has complementary functions that call for effective interaction and cooperation. The goals need to be closely aligned. Their common objectives necessitate that participants share a consistent vision to achieve the best outcome for the interests they serve, both public and private. The reliability of the power system and the competitive electricity market that has been established are a benefit to

participating customers. For these benefits to continue to accrue, we all need to be cooperatively and diligently working together.

Conclusion

Transmission is a small cost and well worth the investment to secure the significant benefits of an unconstrained market. Competitive generation markets will not work with an inadequate transmission infrastructure. As the market facilitator, transmission enables new generation by ensuring non-discriminatory and efficient transport to market. Policy makers need to take the initiative to fill any and all policy gaps that are barriers to reliable transmission systems and robust, vibrant electricity markets. It must be very clear which institutions are the guardians of reliability, and these institutions must be given statutory authority to carry out their responsibility.

We are all in this together, and we have to make it work

Competitive Power Markets and Grid Reliability: Keeping the Promise

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Introduction

The electricity industry in North America has come through a decade of fundamental and far-reaching change. In fact, we are coming up soon to the tenth anniversary of Federal Energy Regulatory Commission (FERC) Order 888, which, along with the 1992 Energy Policy Act, is widely regarded as the defining step in the launch of competitive electricity markets in the United States (U.S.) (FERC 1996).

In Ontario, we were not far behind. In 1996, the Macdonald Committee advised the provincial government to unbundle Ontario Hydro and introduce competitive markets (Macdonald Committee 1996). In late 1997, a government White Paper announced a plan for moving to full wholesale and retail competition in 2000 (Ontario Ministry of Finance 1997). The Ontario market opened in the spring of 2002 but has undergone some major changes, which are described below.

The scope and speed of the industry's transformation has been amazing. Huge companies have been unbundled and reassembled. Ways of doing business have been dramatically changed. Regulatory regimes have been re-engineered. No other industry restructuring compares: not telecommunications, not gas, not airlines.

Another significant transformation is currently under way as the industry moves into a second, distinct phase of market evolution. In "Phase I" governments and stakeholders rushed ahead with enthusiasm, and perhaps some naiveté, to build the first generation of electricity markets. The focus was primarily on technical aspects of market design and the rules, protocols, and software required to implement a market. In "Phase II" we are assessing what we have learned, in a broad sense, and developing strategies to help the markets transition to a more robustly competitive form. In this second phase, we will see *relatively* more attention to issues such as raising reliability standards, making standards enforceable, reducing inter-market seams, improving planning and coordination, securing resource adequacy, and, generally, managing the broader environment in which the market is embedded so that the market is sustained and nurtured.

This paper is part of the U.S.–Canada Power System Outage Task Force’s study of industry restructuring, competitive markets, and grid reliability, and in particular, of how the relationships among these elements should be managed to best serve the public interest. The specific question is: how do we ensure reliability as industry restructuring rolls forward (U.S.-Canada Report, 2003)?

We need to start with a common understanding about what “reliability” means. There are two dimensions to the concept. They are:

- *Adequacy* – there must be sufficient generation to meet peak load and enough transmission and distribution capacity to get it there; and
- *Security* – the system must be operated within studied limits, and according to industry standards, so as to remain stable, protect lives and equipment, and ensure continued electrical service through storms, forced outages, and other contingencies.

The first dimension of reliability is often measured by the criterion that load will not be curtailed more than once in 10 years because of insufficient supply. The second dimension can be measured by assessing the number and severity of power outages caused by equipment failure and/or operator error, the amount of time taken to restore service following transmission and distribution interruptions, and so forth.

This paper takes a historical approach. Part I reviews how reliability was managed in the pre-market period. Part II discusses the current reliability model and some of the general issues it raises. Part III presents 10 lessons that we have learned about restructuring and the introduction of markets; these lessons are fairly broad in scope but directly linked to the reliability question. Finally, Part IV suggests a program for improving reliability in the future and, more importantly, ensuring that reliability remains at the forefront of our thinking as the market evolves.

The Old Reliability Model

As a point of reference, Part I begins with a description of the reliability model with which the industry grew up.

Adequacy was ensured by planning, building, and maintaining substantial generation reserves. Capacity could be built ahead of need. Rarely used peaking plants could be financed because the integrated utilities enjoyed assured cost recovery through regulated rates paid by captive customers. This was the essence of

the model. Typically, utilities maintained installed capacity that was 12 to 25% above their peak requirements.

Security was ensured through generally "conservative" operation of all equipment, and the eventual emergence of industry-wide standards (NPCC 2005). In retrospect, we can say that operational success during these years was cushioned by the fact that most systems had been generously built and contained significant redundancies. Utilities were subject to local regulatory oversight (including, in some cases, direct political control) and operated under a general commitment to "good utility practice."

Utilities were vertically integrated, for the most part, and had an "obligation" to serve their local load.¹ They were originally self-sufficient, or nearly so. Gradually, interconnections were built to facilitate inter-control area trades and support reliability. Long-distance commercial trading increased during the late 1990s with the adoption of open-access transmission, using transmission capacity that was judged to be surplus to the requirements of the native load.

There were no wide-area reliability standards until after the 1965 Blackout when the utilities took the initiative to establish the current network of Regional Reliability Councils and the North American Electric Reliability Council (NERC). The standards that were developed in ensuing years were taken very seriously by the industry, but they remained voluntary.

The Current Reliability Model

Restructuring and the introduction of markets brought about significant changes in the old reliability model.

The demise of the franchise monopoly system meant, among other things, an end to the historic obligation to serve.² Responsibility for ensuring adequacy was, in effect, transferred from the utilities to the market. This has been a critical aspect of the move to competitive markets.

¹ The obligation to serve consists of both an obligation to connect and an obligation to supply. The latter component is of primary interest in this paper.

² The obligation to connect devolved to the unbundled transmitters and distributors. The obligation to supply generally became an "obligation to deliver" to default (or system) customers assuming that supply was physically available.

At first, it was generally thought that the energy market could ensure adequacy on its own. Energy prices would accurately reflect scarcity and would rise to draw in the required amount of investment in generation and transmission. Locational pricing would ensure that investment also went to the places where it was needed most.

This view quickly ran into difficulty, for three reasons:

1. Electricity-sector investment generally dried up in 2001-2003 following the California market implosion, the Enron scandal, and the general collapse of credit markets and the merchant power industry. This experience showed that investment flows are heavily affected by factors beyond just the prevailing balance between demand and supply in a given market.
2. Governments and regulators decided that they could not accept the occasionally high energy prices that the market model clearly implied, even if the price spikes were short-lived and everyone had opportunities to hedge themselves through contracts or changes in consumption patterns.
3. There was growing awareness that the investment and pricing rules of the textbook competition model are for a generic widget industry and may need to be significantly refined in order to work in an industry like electricity where there are distinct peaking and base-load production modes and where the product must be consumed the moment it is produced.

As a result of these three realizations, a great deal of work is being done on how to supplement the energy market and ensure resource adequacy over the medium and longer term. Various capacity markets have been designed, and in some jurisdictions such as Ontario, it has been found necessary to arrange for centralized procurement on a transitional basis. This is discussed in more detail in Part III below.

The new reliability model also involves significant changes related to system security. New organizations – the independent system operators (ISOs) – have been established and given authority for system security. Reliability authorities that are functionally separate from commercial entities have greater influence than they would otherwise, which supports the reliability objective.

The existence of competition is, of course, a new factor in the reliability equation. There are a number of ways that competition can impact reliability. For example, it is sometimes alleged that short-term profit maximization in competitive electricity

markets will lead firms to run their equipment too long and hard or to cut costs in potentially irresponsible ways, thereby impairing reliability. It is also alleged that new trading patterns have greatly increased congestion and that the increase in small-scale renewable and gas generation has negatively affected system "inertia" and stability. On the other side is the pro-competition argument: that competition leads to trade and greater interconnectedness of control areas, thereby boosting reliability, and that more frequent congestion is actually a sign that existing facilities are being used optimally.

These claims must be evaluated empirically, but the task is daunting. We also need to address the issue of benchmarks. It is not easy to compare the reliability performance of market-based systems with that of non-market based systems because there are important differences in the underlying physical assets being operated. It is also not easy to compare the reliability performance of the current period with that of the pre-competition period because many of the specific phenomena affecting reliability (both positively and negatively) would likely have arisen anyway, only more slowly (e.g. the move to gas, renewables, and distributed generation).

More important than all of the above changes, however, is the fact that reliability became in principle a *joint* responsibility of the ISOs and market participants, through licenses, market rules, and industry standards. Large numbers of independent power producers and some independent transmission providers that did not previously exist now had to be brought into the reliability framework. In addition, agreements had to be negotiated allowing the newly independent ISOs to direct the operation of equipment owned by the transmitters. In the new model, the ISOs still have ultimate accountability for system security, but they do not have as much direct "command and control" capability as their predecessors had. Today's controllers have to work with and through their new reliability partners. This raises a number of issues about education, communications, and the enforcement of rules and standards that are addressed in Part III.

The emergence of the new reliability model seems to have been somewhat accidental. There was a great deal of thinking in the 1990s about market design, but reliability was treated almost as a given. Even though "enhancing reliability" was usually mentioned as one of the objectives of industry restructuring, it was never treated as one of the *primary* objectives, and there was little discussion about the details. The pure energy market model of investment showed that adequacy would be taken care of, more or less automatically, and it was assumed that market discipline and transparency would be a real help to the operators as far as the effects on system

security. Moving forward, we need to bring reliability back to a central position in our thinking about the electricity market. That is the theme of Part IV of this paper.

Some Lessons from the Industry Restructuring

But before moving to the "future" part of the story, it is important to spend time on some of the key lessons we have learned from the restructuring of our industry over the past decade. This section identifies 10 lessons that are especially germane to the topic of reliability.

These lessons fall into three main categories that can be called the "three pillars of market evolution":

1. The first pillar, or group of lessons, concerns the need to design markets carefully, build stakeholder consensus, and move forward in a methodical, step-by-step fashion.
2. The second pillar is the need to minimize restructuring risks by building in safeguards. Attention should be paid not only to the market *per se* but to parallel, supporting reforms. For example, strengthening reliability standards and making them enforceable is a critical complement to the introduction of competition and markets.
3. The third pillar is the need for realistic transition measures – a system of off- and on-ramps – so that the industry can move from the old way of doing things and embrace the new. A key example here, which is discussed more fully later, is the need for a backstop mechanism to ensure adequacy in the event that the competitive market alone proves unready or unable to provide enough supply.

In other words, we not only have to get the market right – its rules, procedures, algorithms, and settlement engines – we also have to build the conditions for market acceptance and success. In building and improving markets, we have to ensure that the pace of change does not outrun the capacity to absorb change.

The first three lessons relate to the first pillar of market evolution, the need to design markets carefully.

Lesson 1: The Need for a Balanced Approach

Markets work well most of the time, but they require constant care and may sometimes need to be "paired" with non-market mechanisms. We need to be pragmatic in determining what parts of the electricity sector are amenable to ongoing competitive markets, what parts are amenable to competition but not ongoing markets, and what parts, if any, are not amenable to competition at all. These issues are discussed in general in this lesson and in more detail with specific examples in subsequent lessons.

Ten years ago, the movement to establish competitive electricity markets was building momentum, and the introduction of markets was often portrayed as the panacea that would solve all the problems of the old vertically integrated utility model. Not only would there be an energy market, there would (eventually) be markets in reserves and many ancillary services as well as market-based approaches for managing congestion. Transmission would be provided on a merchant basis. If there were problems in ensuring adequacy through the energy-market-only approach, a *capacity market* could be designed to handle them.

The revolutionary fervour that was evident in the 1990s was probably necessary to ensure that the old utility model was defeated and that a leap to competitive markets occurred in many jurisdictions. But we have now become much more realistic about the role that competition and markets can play in an industry such as ours. Realism has intruded in several ways.

First, we have grudgingly come to accept that in certain cases markets might not work particularly well or even at all. For example, a merchant investment process, based solely on market prices, cannot be relied on for the timely delivery of nuclear power plants and trunk transmission lines. These are massive projects with very long lead times and super-normal risks. There is general agreement in the industry that such projects will usually require some form of financial guarantees as well as a great deal of co-ordinated forward "planning."³

Second, we are coming to terms with the fact that in many cases our markets fall far short of the textbook requirements for robust competition. There are serious market power problems in some markets, with dominant generators holding far more market share than is compatible with even loose definitions of "workable

³ Planning in the "pure" market approach entails little more than publication of a long-term demand forecast. The challenge of "coordinating" investments is left up to the market and the transmission connection process.

competition." We need to work on structural reforms to mitigate market power and to work constantly at eradicating anti-competitive market behaviour. If we do not succeed in these efforts, the market will not deliver the social benefits that it was intended to deliver. If structural flaws in the market are not adequately addressed, the market will ultimately become dysfunctional. There is a much greater appreciation now than there was 10 years ago of how serious this issue is.

Third, we have become more realistic about the broader political environment in which we live. Electricity markets deliver what is widely perceived to be an "essential service." The service, therefore, has to be provided extremely reliably, and its price has to be politically acceptable.⁴ Moreover, the electricity industry is highly "visible" and takes criticism from many directions. The public has strongly held concerns about matters like nuclear safety, facility siting, and environmental emissions, and high expectations that these concerns will be addressed. In the early years, many of the more ardent market reformers chose to overlook these political realities or to see them as somehow unconnected with the success of market evolution. Political constraints, and the multitude of public views and objectives impacting the electricity industry, will have to be taken more seriously as we plot the next 10 years of market evolution.

In Ontario, politics most recently intervened in the form of the *Electricity Restructuring Act, 2004*, which establishes what we call a "hybrid" model in the province (Bill 100 2004). The bill filled a number of perceived gaps in the first generation-market model. Among other things, it created the Ontario Power Authority (OPA) as the guarantor of generation adequacy, giving the authority a mandate to procure power under long-term contracts with the costs to be passed through to consumers. The OPA was also given responsibility for long-term integrated system planning. In addition, merchant transmission no longer figures prominently in the accepted long-term vision for Ontario's electricity sector.

Many of the initiatives in Bill 100 have their counterparts in neighbouring electricity jurisdictions. Resource adequacy mechanisms are being actively explored, and the foundations for wide-area planning are being laid across the entire northeast. Resource adequacy is addressed in more detail later in this paper.

⁴ If this seems obvious, we should remember that not long ago serious people were proposing markets with no price caps or protections at all. As noted later, public anger over spiking prices caused the Ontario Government to freeze retail prices a mere six months after market opening.

All of us who have been involved with the first generation of competitive electricity markets have become more deeply aware of the difficulties in achieving robust competition, and most of us now recognize the need to move ahead carefully, using supportive and complementary *non-market* mechanisms when necessary, often in a transitional manner. Reliability must be fully integrated into our plans for the future evolution of the market.

Lesson 2: The Need for Local Solutions

Every market has to be built with careful attention to local history and politics, the physical and business structure of the inherited supply system, the nature of electricity demand in the area, and the degree of interconnectivity with the system's neighbors. There are always things to learn from elsewhere, but this knowledge has to be filtered carefully. There are no cookie-cutter market designs that can be expected to work in every place, every time. Effective and successful market design depends on serious attention to the details of the system in question.

In Ontario's case, for example, several unique circumstances have definitively shaped the market. They include:

- Comparatively heavy dependence on nuclear power that is provided from comparatively large stations
- Public ownership, at market opening, of more than 80% of all generation capacity, through Ontario Power Generation
- A highly fragmented distribution sector
- A strong government commitment to maintaining a uniform energy price at all locations in Ontario
- Important interconnections with both market and non-market based neighbours
- One hundred years of power at cost as a public good
- Ten years of frozen, subsidized rates prior to market opening

It is also important to note that the Canadian constitutional framework has been different from that in the U.S., which has allowed Ontario to have mandatory and enforceable reliability standards right from market opening.⁵

The need for the type of regional diversity that this paper refers to is now broadly accepted. In the U.S a few years ago, FERC was calling for rapid movement toward a relatively rigid Standard Market Design (SMD) and was promoting the amalgamation of control areas into four super Regional Transmission Organizations (RTOs) for the entire U.S. (FERC 2002, FERC 2003a). FERC has now modified its agenda and timetable, recognizing the need to permit more diversity in how market principles are implemented (FERC 2003b). A more measured and careful pace for market development clearly makes sense, provided we are all following the same basic principles and are committed to eliminating unreasonable barriers to trade.

In terms of the present inquiry about restructuring and reliability, my opinion is that tailoring the first-generation markets to local circumstances supported reliability. Had restructuring involved a single, top down, one-size-fits-all approach, there would almost certainly have been more operating challenges and higher risks of system failure. The markets are evolving toward more compatibility, but we have to move ahead on this issue one step at a time.

Lesson 3: The Need for a Reliability Champion

The introduction of electricity markets has been a paradigm shift in the organization of our industry. Most of us who were involved experienced it as a “revolution.” Building markets was unquestionably a very large challenge, and in Ontario, the Independent Electricity System Operator (IESO) was involved right from the start – in the beginning as the Central Market Operator (CMO) running a fledgling procurement market from within the old Ontario Hydro; then as the Independent Electricity Market Operator (IMO), designing, building, and running the first-generation Ontario wholesale market; and now as the IESO running the wholesale market and working with other agencies to ensure the success of the new “hybrid” system.

Throughout the restructuring, IMO/IESO spoke out strongly in defense of reliability. For us, reliability is the number one priority. During the period from 2000 to 2002, we were adamant that we would not give the “go live” signal for market opening

⁵ Ontario already has in place a statute based scheme for setting and enforcing standards. Under Ontario law, IESO establishes reliability standards and enforces these standards.

unless we were absolutely certain that the transition would be technically successful, and it was.⁶ More recently, we cautioned the government about the reliability implications of trying to close all coal-fired generation plants by the end of 2007, especially the adequacy and security implications of closing Nanticoke, which is a critically-located approximately 3,900-megawatt (MW) facility. The closing of Nanticoke was recently deferred, largely on the basis of the IESO's intervention.

In reflecting on these and similar experiences, we can see that it is important that we – the reliability organization – were a separate and independent entity with direct access to government and regulatory authorities. We had credibility, and, in the end, we were listened to.

I suggest that the voice of reliability is likely to be stronger coming from ISOs, like the IESO, than it would be coming from entities where the (short-term) reliability function is organizationally part of a profit-oriented company, such as an Independent Transmission Operator.

(Lessons 4-7 fit within the second pillar of “safeguards.”)

Lesson 4: The Need for Mandatory Standards

As mentioned earlier, there is continuing uncertainty and, hence, experimentation, regarding how to ensure adequacy in competitive electricity markets. In contrast, there is complete agreement on the importance of standards in supporting and enhancing secure operations. The reliability standards originally developed through NERC are being upgraded and complemented by parallel business practice standards developed by the North American Energy Standards Board (NAESB) (Joint Interface Committee 2002). More importantly, there is strong industry consensus that the voluntary standards of yesteryear have to become mandatory and enforceable and that sanctions have to be meaningful. In Ontario, reliability standards are incorporated into market rules, along with market features, and are legally enforceable.

⁶ The Ontario market, which had been promised for 2000, opened on May 1, 2002. The delay had multiple causes, including uncertainty regarding the recovery of laid-up nuclear capacity, the unreadiness of the retail sector, and a variety of challenges in settling rules and tools. The market rules and software worked admirably, but heat-related price spikes in August, September, and early October 2002 caused the government to freeze retail rates at an unrealistic level. A new government was elected in the autumn of 2003 and passed Bill 100, establishing the current hybrid model in December 2004.

Recently passed reliability legislation in the U.S. will make standards fully enforceable in that country. Work is also underway on establishing a new electric reliability organization (ERO) that would replace NERC and (presumably) provide more pro-active support to the standards process.

Auditing for standards compliance is an important aspect of the reliability framework. Standards have to be monitored and enforced with appropriate levels of deterrence. This is a challenge because a lot of oversight machinery must be built, and numerous jurisdictional issues will have to be overcome along the way.

Lesson 5: The Need for Inclusive Processes

Another important safeguard is having fair, accessible, and transparent processes with rights of appeal. Most jurisdictions consult widely and have either voting or advisory bodies on all aspects of the market rules and market administration. Across North America, a great deal of process re-engineering is going on with a view to improving the effectiveness of the consultation process.

Maintaining an inclusive, cooperative market evolution process is an important support to reliability because it fosters recognition of the mutual benefits of compliance with the rules and standards.

Lesson 6: The Need for Effective Communication

Effective communication is another critical safeguard. Because the main focus of this paper is reliability, let me first address communication at the control-room level.

The August 2003 Blackout was largely about communication. There was a computer failure that hid from operators what was happening on their lines. More important, there was what the investigators called a lack of “situational awareness,” which resulted from insufficient training, insufficient drills, and insufficient understanding of the importance of communicating with neighbouring control areas. *Enforceable* standards on training and communications are among the remedies proposed by the Blackout Task Force.

Although there were communication failures in the 2003 blackout, there has generally been an improvement in the amount of day-to-day communication among control rooms, both to facilitate trade and to improve reliability. For example, ISOs in the northeast now have a much better understanding of what is happening on

each other's systems through the implementation of electronic sharing of day-ahead and real-time information.

Information sharing is also a critical safeguard at the market-participant level. Participants need timely, accurate, and relevant information on which to base their decisions. It is important to emphasize that, when information is late, incomplete, or otherwise deficient, there may be opportunities for some players to try to game the market. Gaming would bring the credibility of the market into question and could also involve behaviour that challenges the ongoing reliable operation of the grid. Therefore, providing quality information is important, not just to those using it, but to everyone who is connected to the grid and counts on reliable service.

Lesson 7: The Need for Consumer Education

The final safeguard we will discuss is consumer education. This obviously fits closely with the earlier points about effective communications and inclusive processes. A base level of consumer education is needed to support conservation and reliability, both in the medium term and when emergency appeals are necessary. More fundamentally, consumer education is needed to drive price responsiveness. Consumers need to be given clear information about short-term electricity prices as part of a package that supports price responsiveness on an hourly and daily basis, so system reliability can be supported through peak shifting or peak shaving. In addition, consumers need to be learning about long-term price trends to drive investment in conservation and demand response.

Probably every jurisdiction has learned that consumer education requires many times more money than is actually being spent. This is particularly true in the retail market, but it is also true in the wholesale market, where changing market rules and changing market-participant personnel make market-participant training a large, ongoing commitment.

In Ontario, we have learned a few painful lessons about communications/education. Our efforts in the retail sector between 2000 and 2001 suffered from an "on-again-off-again" problem as market opening was delayed several times. Our efforts also lacked focus, as various agencies were involved in sending out material, including the government, local distributors, and independent retailers. Finally, and as might have been expected, there were inconsistent messages about what "deregulation" meant for the retail consumer.

The key thing about consumer education is that it must be *meaningful*. It must have resonance for those actually making financial and consumption decisions. Education dollars are not being well spent when the recipients of the education lack the hardware and other tools to participate in the market. We will return to this point shortly.

(Lessons 8-10 relate to the third “pillar” of market evolution: the need for transitional mechanisms, or off and on ramps. We begin to examine this subject by delving deeper into the question of resource adequacy.)

Lesson 8: The Need for a Resource Adequacy “Mechanism”

As explained earlier, concern about adequacy arises once the historic obligation to supply is terminated, and the industry tended to take adequacy for granted in the 1990s, steaming ahead with restructuring in the belief that the energy market would solve the problem unassisted. There was “faith” that the market would deliver new generation and transmission without prices having to go sky high before investors took the plunge and put iron in the ground.

For the reasons given earlier, faith soon evaporated, leading to a long period of debate and experimentation about different ways to address the adequacy question, given the political constraint of energy price caps.

One of the main things we have learned (or re-learned) is that reserves are a “public good,” to use economists’ terminology, and that, accordingly, there has to be a *societal* process for determining what the level of reserves should be. There is simply no way for a decentralized *market* process to arrive at a sensible reserve ratio and then deliver the agreed-upon margin. A pure market-based process that tries to define the “efficient” level of reserve by constantly testing for the minimum (i.e., by letting the lights go out) is simply not sensible or acceptable.⁷

We have also significantly clarified our thinking about how the reserve target can be met, once it has been established.

- One option is to give the dominant supplier a *de facto* obligation to supply by ordering it to build generation. We see elements of this approach in Ontario whenever OPG is instructed by the government to undertake specific generation investments.

⁷ In determining future reserve requirements for electricity generation, some recognition is given to the fact that, on a very infrequent basis, there could be shortages in supply. In practice, day-to-day operation involves taking extraordinary efforts to avoid any supply shortages.

- A second generic option is centralized but competitive procurement, either via auctions such as Capacity Markets, or in which an independent agency enters long-term supply contracts on behalf of the market as a whole. The latter is the primary instrument we are currently using in Ontario, under the new OPA.
- A third generic option is a decentralized procurement process in which entities – Load Serving Entities (LSEs) – are assigned a portion of the reserve requirement and obligated to secure it through contracts with generators. There has been considerable experimentation with this approach.
- Another generic option is targeted assistance to generators who invest in locations and products deemed important by the newly emerging “regional plans.” This category covers miscellaneous actions that governments and regulators might occasionally take to support adequacy, for example, by expediting approvals, assisting with siting issues, providing tax relief, and so on.

The OPA is a new entity in our system, and is independent from the IESO and the commercialized successors of the former Ontario Hydro. It is responsible for contracting for long-term power and is currently doing this based using a request for proposal format (the OPA will also administer the contracts under which the government recently acquired new clean and renewable generation). The OPA is expected to negotiate risk-sharing arrangements in these contracts creating more balanced contracts than the old non-utility generator (NUG) contracts negotiated by Ontario Hydro.

It is widely understood in the Ontario electricity industry that the procurement role of OPA is to be transitional in nature, defined largely by the fact that, within a single decade, Ontario has to replace all its coal-fired generation plants and address the even larger question of nuclear refurbishment / replacement. OPA procurement is done on a competitive basis, and winners participate in our market, so the process is better than having everything built by a single monopoly as in the old days. But investors are still getting some level of "guarantee" from the market, which is something we need to get away from eventually. That said, investors do need assurances that rational market behaviour will bring reasonable rewards, if not through guarantees, then by market mechanisms that are robust against political or regulatory interference.

In short, the OPA was invented as a transitional device to assure the market and the government that there will be enough power to go around. The story is a little more complex, however, because it was also given a mandate as supplier of last resort and a mandate for long term, integrated planning. These do not seem to be transitional mandates; it appears they are intended as permanent features of the hybrid model although the manner in which they are exercised will have to evolve over time. Their purpose is to address perceived gaps in the “pure” market model. One such gap concerns generation mix, which was mentioned earlier.

The electricity industry is unique in that a single product, a megawatt-hour (MWh) of energy, can be produced using several highly distinct technologies, including nuclear, hydraulic, coal, gas, and wind. These technologies differ greatly in terms of their costs, their operating characteristics, and their environmental impacts. We have learned that a pure market-based approach to generation adequacy will not optimize among these alternatives to give the best social result, or, in more technical terms, will only do so under the unrealistic assumption that all “externalities” are fully and properly priced. A decentralized, free-market approach could lead to a generation mix that does not satisfy our operating reliability requirements. For example, it could result in the system becoming unbalanced in terms of its base versus peaking capacity, or becoming overly dependent on intermittent sources, such as wind. So we are led back to the need for long-term system planning. In the “transitional” period that characterizes many of the North American markets, the plans will provide guidance to those administering competitive procurement processes, whatever form the latter may take.

Lesson 9: The Need for Appropriate Tools

We need to ensure that market participants have not only the education, but also the tools they need to participate in the market. There must be a well-planned transition by which they get the physical tools and the training to function in the new market place.

A good example is metering. A decentralized, market-based system requires accurate metering data and efficient settlement processes. In pre-market Ontario, relatively few large and almost no small customers had good-quality interval meters. The Government has now launched a program under which all customers will have “smart” meters by the end of 2010 (Smart Metering Initiative 2005).

Putting appropriate metering in place can be thought of as a transitional step that brings customers into the real world of hourly priced electricity where they have to

take responsibility to either hedge themselves financially against price swings or take steps to be able to curtail use when prices are high.

Metering is very important because, in order for the market to work properly, there must be a large number of price-responsive buyers. Smart metering will likely induce large-volume customers to become more price responsive even if they do not become dispatchable by the system operator. Smart metering at the retail level will encourage conservation and peak shifting if it is accompanied by smart rates, appropriately targeted education, and perhaps a few other incentives. The consequent reduction in peak demands and transmission loading will translate into significant reliability benefits.

Lesson 10: Protecting Consumers

The final restructuring lesson is the transitioning of consumers to the new world of retail choice. Aspects of this issue were addressed earlier under the topics of consumer education, communications, and the need for open and inclusive processes.

The point I want to make here is the need for clear political and regulatory direction regarding how default supply will be dealt with in the medium and longer term. Will there be a default supply, and if so, what will it look like? Will all consumers eventually have to exercise a positive choice even if the result is staying with the same distributor? There has been a huge amount of debate all across North America on whether or not the retail market will ever take off and what it would take to make this happen.

In Ontario, independent retailers have signed up only a very small portion of the total market. Most residential customers are currently paying for their electricity under the Regulated Rate Plan for default consumers; the plan was developed by the Ontario Energy Board and features rates that vary according to consumption and time of year (Regulated Rate Plan 2005). Rates under the plan are intended to eventually recover the full costs of the electricity consumed but will be averaged to protect default customers from daily and weekly price fluctuations. Alberta has recently made the decision not to expose default customers to market rates starting in 2006 but instead will extend its regulated rate for five years, with a blended-price approach that eventually phases customers to the market rate (Alberta Energy and Utilities Board 2005).

The success of the retail market is important to the success of the entire market and to the realization of the efficiency gains, we set out to achieve back in the 1990s. For markets to work optimally – and to be sustainable – we need depth and liquidity, and bringing the retail load “to market” will be a major help. Depth and liquidity, in turn, foster confidence. Confidence leads to investment, and investment leads to more resources and better equipment, which are the technical underpinnings of reliability.

So, even if our restructured electricity jurisdictions end up for the foreseeable future with only a wholesale market, or a wholesale market with a weak retail companion, we need to keep retail competition alive as a goal. In Ontario, we may need to rethink the whole subject, from default rates all the way through to the creation of LSEs, which do not currently exist in our province. We need to get busy on a step-by-step plan for addressing the issue of retail competition.

From Present to Future: Investing in Reliability

The previous section describes a number of “lessons” related to the electricity restructuring experience of the past decade, a decade in which jurisdictions were going through a trial-and-error process of introducing the first generation of market models. Major efforts were made to get the market designs in place, to get the infrastructure up and running, and to work out the kinks, all the while keeping stakeholders engaged in this monumental undertaking.

We were concerned about maintaining the reliability of our systems as we made the changes of the past decade. You can’t take an electricity system down in order to make a change; it has to run smoothly, and the lights have to stay on, while one whole way of doing business is replaced by another.

By the same token, as noted earlier, there was a sense in which the industry took future reliability for granted. Adequacy would be taken care of by the market, and security would probably be helped by the market as well. We were not consciously *investing* in reliability to the degree we should have been. This final section of the paper focuses on to how we need to turn this mistake around: how can we start *investing* in reliability?

The subsections below describe three priorities: standards, infrastructure, and reducing seams and aligning markets for investing in reliability.

Priority 1: Standards

Mandatory reliability standards are essential. Reliability legislation has now passed in the U.S.⁸ This is a historic breakthrough and the culmination of many years of hard work. The symbolic and practical importance of mandatory and enforceable standards cannot be over-emphasized. NERC should be commended for recent improvements in its audit process, specifically the introduction of readiness audits, and for strengthening its Compliance Enforcement Program. These are important steps in making the transition to the mandatory, legally enforceable standards that congress is expected to recommend to the President later this year.

We also must move ahead with the proposed ERO.⁹ There are several important governance and funding issues to resolve, but this organization is pivotal to the future of electric reliability in North America.

We must recognize the importance of local conditions and practices when it comes to setting standards. Although, as noted at the beginning of this paper, local and regional tailoring are very important in the design of first-generation markets, we should keep in mind the ultimate objective of standards that are as encompassing as possible. We need standards that evolve and constantly challenge us, not lowest-common-denominator standards that merely ratify existing practices.

To date, most standards have been produced through industry committees and organizations, usually following an accredited American National Standards Institute (ANSI)-based process.¹⁰ The market system requires that we further examine the process by which standards are produced. For example, although it is essential to have a broadly based, participatory process, we may need to assess how well priorities are being set and whether or not there is sufficient coordination in the development of electricity reliability standards and business practice standards, respectively. And we may need to involve regulators directly in the drafting (as well as the enforcement) of the standards.

Priority 2: Infrastructure

In most areas with which I am familiar, there is a need to address historic shortfalls in transmission investment. While markets were being introduced, transmission investment somehow fell behind. This was due to a variety of different circumstances: the unsettling effects of all the corporate restructurings, uncertainties

⁸ The U.S. President signed The Energy Policy Act of 2005, on August 8, 2005.

⁹ It is expected, but not certain, that NERC will evolve into the ERO.

¹⁰ ANSI certifies the processes used to establish industry-wide standards. Both NERC and NAESB follow ANSI-certified procedures.

regarding where transmission would best be located given a rapidly changing picture of generation location, regulatory risk, the often-interminable approvals process, nagging questions of how to recover the costs of investments, and of course, the ever-present “not in my backyard” (NIMBY) attitude.

This in fact may be the strongest charge against restructuring: not that it changed incentives adversely but that it simply distracted attention from needed investments and shifted “too much” attention to market building. In any event, recognition is growing of the critical role of transmission in supporting wholesale electricity markets. In recent testimony before the U.S. Congress, FERC Chairman Pat Wood III stressed the need for a more modernized and efficient grid, noting that, “Underdevelopment of the transmission grid impedes the achievement of the benefits of competitive markets” (Wood 2005).

In Ontario and a number of other jurisdictions, the need for a “broader perspective” on investment is recognized in the new planning organizations and committees that have been formed to look at integrated planning over the long term. This is a somewhat belated recognition: that adequate generation is actually inadequate if you can’t deliver it to loads effectively, and that the transmission business is not particularly amenable to competition, per se.

Ontario has moved away from a merchant transmitter model in favour of a model in which most (but not all) transmission investments will be recovered through rolled-in rates paid by all customers. Transmitters are required to submit regular plans regarding network investments.

As part of the renewed emphasis on upgrading the transmission network, we will need to consider new technologies that address the specific issues raised by markets and long-distance trade. For example, more investment is needed in wide-area visibility, such as can be provided by phasor measurement systems developed by the Consortium for Electric Reliability Technology Solutions (CERTS). There also needs to be more installation at key locations of “fast-acting” devices to provide better management of energy flows, including unintended loop flows.

Priority 3: Reducing Seams and Aligning Markets

In addition to investing in standards development and infrastructure, we will need to expand our efforts to address trading seams between and among markets. Considerable strides have been made in this area in recent years. Export charges have been eliminated between the New York and New England markets. New reserve sharing protocols have been introduced (Reserve Sharing 2004).

Nevertheless, in many markets, there continues to be an unacceptably large number of intertie trading failures. Trading failures in real time can adversely affect reliability. The sudden loss of a large, planned import is an obvious example. Some of these transaction failures appear to be associated with the introduction of new hardware and software or new market procedures. Such failures can be seen as transitional – metaphorical teething problems – and it should be possible to reduce the problem as we gain more experience and communicate more effectively.

Other trading failures are attributable to fundamental differences in design from one market to the next. Of particular importance to Ontario is the fact that we do not currently have a day-ahead market, as do New York and the Midwest ISO (MISO). This makes it difficult for Ontario to secure energy in tight situations using the real-time market. Our market was quite successful in securing needed imports in the critical summer of 2002, but it is not clear that it would be as successful today. Recognizing the reliability risk, the IESO has armed itself with additional out-of-market capabilities in the event that such control actions prove necessary. And we are actively consulting stakeholders on whether to proceed with a day-ahead market or to develop alternative day-ahead commitment processes.

Another key difference in market design is that Ontario does not have locational marginal pricing as its U.S. neighbours do. There is a single, uniform energy price for all loads in the province. The result is that Ontario needs a fairly complex set of rules for settling congestion redispatches (which may have to be carried over into any comprehensive day-ahead market design). The government has stated clearly that it does not want locational prices, so our near-term market design enhancements will continue to respect the uniform price policy for consumers.

Seams issues must be continuously addressed because energy and reserve trading are critical for ensuring reliability in the market paradigm. It is primarily by sharing reserves through trade that jurisdictions can economize on local generation and achieve their reliability target without “over” building. But the approach depends on having ample intertie capacity and good rules that are as compatible as possible with those of the neighbours. We cannot expect to eliminate all market seams, as that would entail eliminating important local variations, but we can and must invest the time and effort to minimize barriers to cross-border trade and thereby achieve at least part of the reliability gains that restructuring and competition were intended to bring.

It is particularly important that, as each jurisdiction develops its market, full consultation and cooperation with neighbours is maintained to ensure that no detrimental market or reliability risks are inadvertently created.

Conclusion

This paper suggests various links among restructuring, competitive markets, and reliability and observes that we are now in a second phase of market evolution, in which we are consolidating electricity markets and broadening our perspective beyond traditional design issues. We are taking a harder look at questions like resource adequacy, standards, and the potential role for planning. We need to integrate reliability into our evolutionary planning and collectively ensure that reliability is maintained and improved as the industry evolves.

Markets and inter-regional trading are conducive to improved reliability, but there is a lot to do to provide support to the market. The agenda going forward should include strengthening standards, improving infrastructure, and reducing trade barriers. We need to think of these efforts as complementary elements in an overall strategy for enhancing reliability, not as singular initiatives. I conclude by proposing an overarching, industry-wide commitment to "invest in reliability" as one approach for managing the restructuring / reliability relationship in the years ahead.

Our understanding of competition and electricity markets is becoming more sophisticated and nuanced; our markets are gradually taking root and achieving liquidity, despite the many bumps in the road getting to where we are today. As we continue to fine-tune and improve, we need to ensure that the promise of reliability is kept.

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Relationship between Competitive Power Markets and Grid Reliability: The PJM RTO Experience

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Introduction

The August 14, 2003 blackout has become a Rorschach test in which every viewer interprets as evidence to support his or her concerns about the problems in today's electric industry. Some observers have asserted that the blackout could have occurred because the advent and spread of wholesale electric competition has made the grid less reliable. To address this question, the U.S. Department of Energy (DOE) and Natural Resources of Canada have invited the PJM Interconnection and others to comment on the relationship between wholesale electric competition and grid reliability. PJM appreciates this invitation and opens with some general thoughts.

As one of the largest grid operators in North America, PJM serves 51 million people, served by many local transmission and distribution utilities across 13 states and 138,500 square miles, meeting a peak load of over 124,000 megawatts (MW) by coordinating the operation of over 1100 generators and managing electricity flows over 56,000 miles of transmission lines and 3060 bulk power stations. While all of PJM's member transmission companies and generators operate in a competitive wholesale market, some PJM states have moved to retail electric competition while others have retained traditional regulated monopolies. The PJM regional economic dispatch and wholesale power market acts as a regional information conduit that coordinates the operation of these diverse participants to ensure that economically efficient operation is achieved in a robust and reliable manner.

PJM believes that wholesale electric competition enhances, rather than compromises, grid reliability. Competition, supported by regional grid managers such as Regional Transmission Organizations (RTOs), brings stronger information, grid management tools and locational prices that make all market participants partners in reliability protection and reinforce and improve grid reliability. In this paper, we will review the causes of the 2003 blackout, examine grid management tools, operator training, and system planning and analysis, and explain why competition and RTOs are addressing those issues and doing more to help improve reliability and strengthen the grid.

Perspective on 2003 Blackout

To understand the 2003 blackout, we must understand utility industry history, the results of studies that have been done on the causes of the blackout, and the data that are (and are not) currently available regarding reliability.

Utility Industry History

Those who assert that “competition” may have been the root cause for the August 14, 2003 outage appear to believe that the need to maximize profits has caused utilities to defer investments and expenditures necessary to maintain reliability. While such investments have certainly diminished, the advent of wholesale competition in 1992 is only one of several drivers affecting utilities’ business decisions. For the past two decades, North American businesses have faced growing competition every day, competing for their customers’ cash in a global economy, and with other companies for investment and human capital. Operation within a vertically integrated, traditionally regulated framework did not insulate utilities from the financial and competitive pressures buffeting electricity sellers and buyers. Although formal competition between electric generators began with the enactment of the U.S. Energy Policy Act of 1992, utilities in fact entered this broader competition in the 1980s, when their ability and willingness to finance new power plant and transmission investments dwindled with higher interest rates and increased competition for investment capital.

In the 1980s and 1990s, utilities experienced an unprecedented level of regulatory scrutiny, following a decade of rising electricity prices due to rising fuel costs, power plant over-building and price over-runs on many new power plants. Capital and regulatory pressures led utilities to cut back severely on new transmission investments, relying on the generous base installed during the 1960s through 1980s, and the utilities began looking for places to cut back operating as well as capital expenses to hold rates down. This led to extensive personnel layoffs at many utilities – in management and back office operations as well as in previously sacrosanct power plants and T&D operations – at the same time the utilities were investing in computer technologies that promised to make operations more efficient and productive without need for increased staff. These factors and the resulting utility retrenchment set the stage for the US industry’s movement to wholesale competition during the mid-1990s, and laid the groundwork for the current situation.

While the North American electricity industry was changing, customers, technology and institutions were changing as well. Between 1980 and 2002, the American population grew 27%; per-capita electricity use grew by 15%; peak demand across the U. S. grew by 28%; and generation capacity grew by 49% (U.S. Census, Annual Statistical Abstracts). During the same period, computing and communications

technologies exploded with new capabilities and applications, penetrating utility operations from power plant operations to control room analysis, system design and planning, supervisory control and data acquisition (SCADA), field operations, high-speed data transfers and communications, and office computing. These technologies transformed the industry's operational capabilities and worker productivity, causing significant structural shifts in the types of jobs performed and the number of workers at every utility.

The electric industry structure evolved through the 1980s and 1990s in response to these changes in finance, technology, operations, management, and regulation. Utilities were forced to lower expenses and operate more efficiently, and to make choices about how to best use every available dollar. Strong over-capacity in both generation and transmission from investments made through the mid-1980s allowed utilities to reduce capital outlays and cut back design and construction staffs without any major reliability problems. But continuing pressures to hold down rate levels and rate increases in the face of high fossil fuel prices forced utilities to look farther afield for cheaper energy sources. Thus the 1980s saw significant increases in long-distance energy purchases by large integrated utilities, including major imports by New York from Quebec and California from British Columbia, the Pacific Northwest and the Southwest. These cross-regional electricity flows pre-dated the growth of wholesale competition, and established the pattern that utilities were eager to buy electricity from outside their service area, or from non-utility generators, to avoid having to run the political and regulatory gauntlet of building a new local power plant.

Some suggest that the grid today is being used in ways that it was never designed to accommodate and that it is facing unanticipated levels of electricity flow, trade and congestion. This observation is half-correct. It is true that the levels of flow, trade and congestion on the grid are unprecedented – but the grid itself has changed as well. It has evolved with more sophisticated analytical, management and communications tools; faster and more sophisticated controls; and new kinds of materials and electronics. Together, these changes have allowed the industry to greatly increase the grid's transfer capability – even without significant growth in the miles of transmission lines during the past 20 years.

The grid's institutions have evolved as well to deal with the changing environment. Pushed by pressure to improve shareholder returns after the poor performance in the 1980s, the last two decades have seen a number of purchases and utility consolidations, to increase size and achieve synergies and economies of scale in generation, operations, customer service, and more. During the 1970s and '80s, every utility that had a generator was its own control area, with limited flows between regions; as flows across the grid increased due to the growth of generation and demand nationwide, it became clear that there was a need for coordinated grid

management across wider regions to protect reliability. During the 1990s, this need, combined with the need to implement wholesale competition effectively, produced the Independent System Operator, which evolved in turn into the Regional Transmission Operator. Today, RTOs and ISOs perform grid operations, system planning, and market operations in 35 states, serving 175 million Americans and 61% of the United States electrical load.

Causes of the 2003 Blackout

The U.S.-Canada System Outage Task Force Final Report on the August 14, 2003 Blackout concluded that the blackout occurred because FirstEnergy failed to assess and understand the inadequacies of its transmission system, did not recognize and understand the deteriorating condition of its system in real time and failed to adequately manage vegetation growth in its rights-of-way; and because Midwest ISO (MISO) and PJM did not provide effective real-time diagnostic support¹. The report documents inadequate system planning by FirstEnergy and ECAR for several years before the blackout, and shows that because the trees within FirstEnergy's 345 kV rights-of-way were quite old – they were measured at 46 to 60 feet tall; two were 14 and 18 inches in diameter. Thus, FirstEnergy's predecessor company practiced insufficient tree-trimming as far back as 1990, before the start of wholesale competition.

The report further examined seven major blackouts in North America which took place in 1965, 1977, 1982, 1996 (two events), 1998, and 1999, and found that all stemmed from a common set of factors: conductor contact with trees, over-estimation of generators' dynamic reactive output, inability of system operators to visualize events over the entire system, failure to ensure that system operation was within safe limits, lack of coordination for system protection, ineffective communication, lack of "safety nets," and inadequate training of operating personnel. Most of these factors were found in the August 14, 2003 blackout, and similarly affected blackouts in 2003 in Italy, Sweden and London. Thus, we note that these factors affected transmission system operations well before the advent of wholesale electric competition in the United States in 1992, and in system operations abroad.

Data are Lacking to Measure Reliability

Grid reliability is a difficult issue to discuss objectively, because few metrics describe and measure bulk system reliability consistently across the nation. Although there are records for measures such as the system average interruption duration index (SAIDI) and system average interruption frequency index (SAIFI), these measures

¹ The Mid-Atlantic Area Council Administrative Board found that PJM did not violate any North American Electric Reliability Council (NERC) or Mid-Atlantic Area Council (MAAC) reliability standards.

describe reliability on the distribution rather than transmission system. The bulk system measure “Loss of Load Probability” is a planning measure for generation adequacy rather than an actual performance measure; and events such as line outages or “blackouts” can vary significantly in duration, magnitude and human impact. The growth in sophistication and availability of grid monitoring has made it easier to identify the slight variations in grid performance that might have gone unnoticed 20 years ago. At the same time, end-users’ dependence on non-stop electricity availability has grown dramatically with more sensitive equipment and higher demand, so their expectations for reliable service have risen as well. Thus as we analyze system performance indices, we must discuss whether and how reliability has changed over time without benefit of objective evidence about the level and characteristics of reliability across those decades.

The Dimensions of Grid Reliability

Key influences on grid reliability are regional dispatch and scheduling practices, regional RTO coordination, and system operator training.

Regional Dispatch and Scheduling

Large RTOs, including PJM, operate real-time economic dispatch and real-time regional wholesale markets to maintain and enhance grid reliability. In addition, day-ahead scheduling of generation using a regional unit commitment process creates a regional generation operating plan that recognizes transmission limitations and thus enhances reliability.

Real-time Wholesale Market Prices Strengthen Grid Reliability

The economic incentives inherent in an RTO-administered market are integral to and improve system reliability. In contrast to a centrally managed system that requires a single operator to manage and direct every activity on the grid, a competitive market uses clear, transparent, commonly available information about grid conditions to communicate simultaneously with hundreds of market participants. Neither the RTO nor the market participants need to rely solely on monitoring equipment and telemetry to determine when and where the system is stressed; through locational marginal prices (LMPs), every market participant can tell when congestion or supply shortages arise and can tell what an appropriate response would be. Locational prices make every market participant a partner in assuring system reliability, because when participants respond to prices in real-time they are acting in a way that improves system reliability.

RTOs, such as PJM, have learned through actual experience that a competitive price for power, derived through the bids and offers of willing buyers and sellers, will

enhance reliability when the price revealed in the market reflects the physical state of the power grid. The market designs used by RTOs (including PJM) provide that crucial information through a regional dispatch constrained by the demands of the network and communicated freely to all market participants; in other words, through LMPs.

Because the LMP model uses actual system inputs from a large number of points on the system and integrates price bids into an algorithm that provides real-time, transparent information about the system, LMPs make all market participants aware of where power needs to be increased or decreased. For example, if a transmission line is congested, the price on the delivery side is high which signals the need for more generation (or less demand). Therefore, any available generation on the delivery side of the constraint will see the price rising and will respond to alleviate the reliability problem because the price incentive and desired reliability response are consistent. Should this constraint persist over time, there will be an incentive to develop a longer-term response, such as demand response investment or transmission upgrades, to resolve the sustained transmission delivery problem. Because these price signals are transparent, all other parties in the market are able to see the effects and act to bring the resources to bear that would relieve the stress.

The crucial aspect of the market that enables market participants to intervene to improve reliability – and gives them both the tools and the incentive to do so – is the real-time energy market based on economic dispatch, which is itself based on real-time assessment of grid capabilities (i.e. “security-constrained dispatch”). The market is thus receiving information continuously about how and where stress is appearing in the system, and is providing – through the higher locational prices becoming available in constrained areas – an incentive for participants to redirect resources where they are most needed, i.e. where the market has shown them to have the highest economic value.

The research of University of Wisconsin Professor Fernando Alvarado and of Rajesh Rajaraman (both of Christensen Associates) suggests that an LMP market would have revealed the increasing stress in the areas where the August 14, 2003 blackout originated in time for action to be taken to avoid the catastrophic failure. As conditions deteriorated (but before they became irreversible), the market would have revealed extremely high prices in Cleveland and Akron as these areas became stressed and overloaded relative to the carrying capacities of the deteriorating transmission system. These prices would have prompted other market participants and the system operator to explore the reasons for the price spikes, taking economic action to increase available resources to take advantage of the high price

opportunities and to take operational action to determine whether the high prices reflected genuine operational conditions.²

In essence, broad markets using LMPs provide an exceptionally robust system for integrating and making available, to market participants and system operators alike, a vast array of data about the system and its operational conditions. In PJM, for example, the “state estimator” (an algorithm used to evaluate the physical state of the transmission grid) provides information for real-time security analysis that anticipates nearly 4000 credible contingencies at nearly 13,000 monitored elements every minute, and incorporates into prices the resulting potential system configurations to ensure that operations remain consistent with conservative assumptions about grid reliability. The information that allows efficient choice of what resources to run and where to run them at any given moment, is precisely the same information, provided in precisely the same way, that allows the market participants and the system operator to identify and resolve threats to reliability.³

Security-Constrained Unit Commitment and Reliability

In addition to operation of real-time economic dispatch and the real-time regional wholesale market, large RTOs, including PJM, enhance power grid reliability through day-ahead scheduling of generation using a regional unit commitment process. This process provides a regional generation operating plan that recognizes transmission limitations. The PJM unit commitment process uses a state of the art Mixed Integer Programming (MIP)-based scheduling algorithm that ensures sufficient generation resources are scheduled, based on projected system conditions and operating margins, to meet operational reliability standards. This forward-looking scheduling process ensures that sufficient notification is given to generation owners if they are needed to respond to system events. This unit commitment engine ensures that generator operating schedules are coordinated with load forecasts, transmission outage schedules and regional powerflow projections so

² Alvarado and Rajaraman, 2003, “The 2003 Blackout: Did the System Operator Have Enough Power?,” August 18, 2003.

³ PJM’s experience thus confirms the DOE’s assessment, made in its 2002 report “Impacts of FERC’s Proposed Standard Market Design” on p. 57 that

- “Independent (regional) grid operators improve transmission and physical and cyber security by:
- Providing system operators with visibility over a larger portion of the transmission system so that operators can better understand the nature of a system disturbance and respond more quickly and effectively;
 - Giving operators control over more resources in order to coordinate a more efficient response to a disturbance;
 - Allowing operator to see patterns of failure that may be indicative of a coordinated attack on the electric system; and
 - Providing operators the ability to better coordinate operations with transmission maintenance activities.”

system operators know that adequate generation response capability will be available to meet ongoing grid operational reliability requirements.

The regional RTO scheduling and unit commitment systems provide a large-scale regional perspective on upcoming grid operations to ensure that both market participants and system operators are adequately informed of potential operational issues with sufficient notice to respond adequately. The regional perspective also ensures that reliability is not compromised because of a lack of information.

Advanced Technologies Improve Reliability

The Task Force outage report found that significant failures in FirstEnergy's Energy Management System (EMS) and MISO's State Estimator on the afternoon of August 14, 2003, allowed transmission outages and problems to exist and spread, undetected, until it was too late to prevent a blackout. The report calls for improvements in grid management hardware and data collection, a broader geographic and electrical scope for grid operations, and improved visualization tools so that operators can quickly understand grid conditions. Within RTO- and ISO-managed regions, these problems have been addressed and reliability has been enhanced as a result of significant improvements in the quality and timeliness of the technologies and tools used to monitor and manage the grid.

Significant computing, monitoring and communications technology investments, and massive quantities of data, are needed for reliable grid operations. In 2004, the Federal Energy Regulatory Commission (FERC) examined the minimum requirements and best practices for reliability software and hardware, in the areas of network analysis, monitoring and visualization, real-time enablers, operations planning, transactions scheduling, grid history and forecasting (Macedo 2004). For all of the measures studied, the North American Electric Reliability Council (NERC) reliability audit program results confirm that only RTOs, ISOs, and a few very large utilities have invested in development and installation of the sophisticated, complex software tools identified as best practices needed for reliable grid operations; MISO's state estimator was under development when the blackout occurred and has since reached full operation. By contrast, many smaller utilities are still using old, patched EMS, state estimator and contingency analysis software that does not allow precise, near-real-time evaluation of grid conditions and threats.

Technology tools, such as SCADA systems to acquire grid condition data and State Estimators and Contingency Analysis models to use these data to monitor and project the grid's condition, are expensive and require a significant amount of support and maintenance. A change in flows or equipment condition at any one of the thousands of telemetered data points can have significant impacts on many other points across the grid, so the interpretive models must receive updated data every

few minutes and run a fresh analysis. Maintaining these systems in service is a constant process of diagnosis and modification. These systems are supported by an experienced staff of information technology professionals, as well as staff who operate the data collection and interpretive models, and others who interpret the models' results in real time. Large, experienced grid operators have the financial, technological and human resources to acquire, operate and maintain such systems; most smaller companies operating smaller control areas do not. Equally important, the RTOs are designing and driving many of the advances in real-time grid analysis and modeling, working with software vendors to identify performance enhancements and needed operating features to improve reliability over a wide-area region. Highlights of these technology advances are explained below:

Real-Time Contingency Analysis and Generation Dispatch

The PJM Security Analysis application runs every minute, processing 68,000 data points every 10 seconds and evaluating almost 4,000 contingencies. The real-time security analysis tools provide system operators with near real-time information on the potential impact of transmission and generation contingencies to help ensure that unexpected events do not lead to cascading failure conditions. Using the security analysis results, PJM redispatches generators to mitigate any contingency overloads. The redispatch is optimized, using automated real-time dispatch technology, to focus on those generators that will have the greatest impact on the contingency. This real-time generation dispatch optimization, which is carried out within minutes of the discovery of a contingency overload, can only be done this quickly using the sophisticated tools developed by RTOs. The response time for alleviating contingency overload events is significantly reduced using this automated unit dispatch technology which has significantly improved overall operational reliability.

Real-time Voltage Analysis

Regional power transfers can have significant impact on voltage performance during contingency events. PJM has developed on-line voltage analysis software that monitors the voltage characteristics of power transfers by re-calculating regional system voltage characteristic curves every 10 minutes based on current system operating characteristics. The automated calculation of voltage characteristic curves gives power system operators' up-to-the-minute information on reactive power transfer limitations which enables operators to avoid the potential for operating near voltage collapse conditions. These voltage characteristics are automatically converted into power transfer limits that are introduced directly into the unit dispatch system to ensure that the deployment of generation resources to meet demand will be carried out within safe limits. Here again, the transparent information that is made available by PJM to market participants - in the form of powerflows, reactive transfer limits and, most importantly, LMPs - empowers

market participants to assist the power system operators by responding to real-time price signals. This transparent market information means that many extra sets of eyes are keeping watch over system conditions and responding to the price incentives to work in partnership with the RTO in maintaining voltage security on the regional power grid.

Advanced Unit Commitment

In June, 2004 PJM deployed new unit commitment software based on state-of-the-art MIP technology. This algorithm more precisely schedules the operation of generating units to support reliable grid operations. The new MIP-based software engine allows the PJM scheduling system to model generation operating parameters and transmission constraints more accurately and completely than was possible in the past. The deployment of the MIP-based engine has not only improved reliability-based scheduling but it has also reduced scheduling costs by improving the accuracy of the model. This new unit commitment program, which is faster and more accurate than traditional Lagrangian Relaxation methods, is the first of its kind in the industry in a large-scale production application. The deployment of a regional advanced unit commitment engine has significantly increased the visibility of the impact of transmission reliability requirements on the regional generation scheduling requirements. This is accomplished because of the fact that the new unit commitment can directly model system security constraints within the generation scheduling process. The previous methods were based on using reduced sized powerflow models. This increased visibility has increased forward reliability coordination across the region which ensures that operators have more alternatives to maintain grid reliability in real-time operations.

Visualization Technology

Large RTOs are addressing the challenge of creating visual displays that can address the magnitude of the grid that RTOs manage and the speed of grid condition changes. Visualization to support real-time grid operation requires new displays that show relevant information to the operators without overwhelming them with too much information. The technology to create displays and paint the big picture of grid conditions is generally available. But the issue of reducing the data to create a useful, complete visual display is an inexact science and flies in the face of the operator's traditional desire to have access to the maximum amount of data. The large RTOs and largest reliability coordinators are making progress in addressing this need. PJM is using new projection technology to facilitate the display of the information to the operators. PJM is also working with software vendors to integrate Geographic Information System (GIS) technology with the power system information, to create a spatially dynamic visualization and decision support tool for better real-time decision-making to protect grid reliability.

Outage Planning and Coordination

The regional scope of the PJM market provides much more comprehensive outage coordination for generation and transmission equipment than is possible in a more balkanized system. PJM has implemented internet-based outage coordination software that ensures coordination of outages over the entire market region which provides a much higher level of outage coordination than can be achieved in smaller, more fragmented systems. Regional outage coordination is important to ensure that unsafe and unreliable operating conditions are avoided through advanced coordination.

Applications Scale and Scope

Grid operators' limited, local view of grid conditions contributed to the 2003 and other blackouts. Smaller control areas do not observe enough of the grid – generation or transmission – to identify and understand all the factors that could affect conditions and contingencies within their footprint, and small operators cannot control all of the grid elements (e.g., through regional power plant re-dispatch) that might alleviate an emerging contingency within their footprint. When a small control area observes only localized conditions, it may craft sub-optimal solutions that do not fully address regional operational problems with high reliability value solutions or high economic value solutions.

One of the biggest advantages of RTO grid management is that it solves the wide-area visibility problem because the RTO coordinates the controls in a wide regional area. PJM's state estimator model contains close to 13,000 busses, with data fed by SCADA systems that span 74,366 metered data points across 56,070 miles of transmission lines and 13 states. PJM, MISO and the other RTOs have worked to expand their operators' real-time visibility beyond the RTO's immediate footprint, reaching two substations out into neighboring regions.

The challenge of successful system operations is to gather the appropriate data and create analytical tools to help operators distill those data into meaningful information about system conditions so that operators can quickly grasp and effectively act to mitigate any operational problem. Data analysis and visualization techniques are critical to this task.

Preserving reliability requires that each operational entity be able to "see" beyond its immediate borders. The analytical tools require data from beyond the operators' territorial limits to ensure that the analyses for the areas inside the territory are accurate. Given this necessity, the RTOs have created the means to exchange the data and feed it into their respective models.

Regional RTO Coordination

As electricity markets are operated over increasingly large areas, managing the interactions of those markets at their borders becomes critical to both reliability and efficiency. The 2003 blackout occurred in part because of insufficient, ineffective information exchanges and operator communications between FirstEnergy, MISO, American Electric Power (AEP) and PJM, while MISO was in early stages of development. The combination of real-time market operations with sound communications and data protocols between RTOs and utilities should limit the recurrence of the 2003 communications problems.

Locational prices that are consistent with transmission constraints on both sides of RTO borders are essential incentives for market participants to act in ways that reinforce reliability. The coordination mechanisms implemented by PJM and surrounding RTOs and Reliability Coordinators give operators real time access to system conditions data for neighboring areas. Access to this information on a minute-by-minute and second-by-second basis allows the system operators conduct security-constrained economic dispatch for each region, producing energy prices that reflect transmission constraints in neighboring areas, thereby supporting reliable operations. Exchange of additional data in the planning and operating timeframes also enhances grid reliability by supporting coordinated planning and operations activities through detailed operating and reliability coordination agreements.

Enhanced operator information through data transfer protocols

The cornerstone of coordination between RTOs and Reliability Coordinators is the exchange of reliability and market data. PJM and MISO have been exchanging various types of data since fall, 2004, when coordination between the two systems began. The two RTOs exchange data that include long-range planning data to coordinate planning models, shorter-term operational planning data to coordinate transfer capability calculations, and two-second EMS data used by system operators in minute-to-minute security-constrained economic dispatch of the two systems.

The real-time data exchanged by PJM and MISO allow the system operators to jointly manage constraints that are affected by flows and generation dispatch from both RTOs. Joint management of mutually impacted transmission facilities is made possible by a protocol for the exchange of data that is necessary for operators to monitor and control flows on transmission facilities in each RTO's footprint. In real time, the RTOs exchange actual flows on coordinated transmission constraints, as well as the instantaneous cost of redispatch to relieve each constraint, so operators can achieve the efficient dispatch across both systems. This dispatch coordination ensures consistent pricing for constraints that are near the RTO borders and provides

the correct incentives for market participants to act in ways that support reliable operations.

Enhanced reliability tools through joint operating agreements

The coordination mechanisms that have been implemented between PJM and MISO are made possible through a Joint Operating Agreement (JOA). The JOA details the responsibilities of each RTO in the coordination process, the data exchange that supports reliability and market coordination, and the settlement that takes place between the RTOs as a result of redispatch for constraints in each other's systems.

The market-to-market coordination between PJM and MISO that is specified in the JOA was implemented as of April 1, 2005 and has already demonstrated significant operational and economic benefits. For example, joint dispatch coordination with MISO for the Wylie Ridge flowgate with MISO has provided PJM operators with more reliable real-time transmission constraint control capability and has saved more than \$4 million in transmission congestion control costs in a one month period.⁴

The JOA also provides for the coordination of scheduled transmission and generation outages between the RTOs, such that potential reliability concerns caused in one RTO by outages in the other RTO are appropriately mitigated. Coordinated real time operations activities in addition to the coordinated dispatch described above are also governed by the JOA, including interchange scheduling checkouts and joint emergency procedures. The JOA also provides for coordinated regional transmission expansion planning, including cost allocation for transmission upgrades required for reliability and that benefit load in both RTO footprints.

Coordination between PJM and MISO has evolved to the point where the transparent locational prices in the two markets react to the coordinated dispatch for mutual constraints. Because of the regional scope, such coordination is also possible with Reliability Coordinators for systems where markets do not yet exist. PJM, MISO and the Tennessee Valley Authority have established a Joint Reliability Coordination Agreement (JRCA) for data exchange, coordinated control of transmission facilities that the combined systems affect, and reduced reliance on the NERC Transmission Loading Relief (TLR) procedure.

The TLR procedure is an emergency procedure that was created to control loadings on transmission facilities through the curtailment of control area to control area transactions. TLR is less reliable than redispatch because it takes longer to negotiate the relief between system operators and implement the relief (up to an hour for transaction curtailments to take effect), and the curtailments may not provide the

⁴ Savings are calculated by comparing joint dispatch results to individual dispatch scenarios.

needed relief. Redispatch, in contrast, targets the generators that have the greatest ability to provide the required relief on the constrained transmission facility at the lowest cost, and can respond to dispatch instructions often in a matter of minutes.

Another important reliability-protecting measure of the JRCA is its coordination of ATC/AFC calculations for transmission reservations, to make sure that transmission service is not oversold and over-congested. The JRCA also establishes coordinated regional transmission expansion planning, to ensure that system planning for reliability adds value and improves reliability within and across each of the partner regions.

Operator Training

One of the principal causes of the 2003 blackout was that the operators at FirstEnergy and MISO were inadequately trained to recognize and deal with multi-contingency and emergency conditions. In contrast, RTOs and Reliability Coordinators invest significant time and resources to train operators and operations support personnel in all aspects of system operations and emergency condition management, including effective communications between control rooms and operators.

Highly qualified and trained personnel are critical for reliable operations, because the systems are so complex and the consequences of operational errors are potentially so great. Some of the most effective emergency training involves simulation, i.e., practicing operational actions under near-real conditions. For the large RTOs, operational simulators are used to create near-real operational conditions so that operators can practice without the negative consequences of errors in actual system operation. PJM's simulation training incorporates videotaping and debriefing sessions in which a shift team can review their actions, understand any errors made, and reinforce critical understandings about the grid and their operational responsibilities.

Following the 2003 blackout, NERC increased its requirements for operator training to include at least 32 hours per year of training with drills in system emergency response, including realistic simulations, for each staff person with responsibility for real-time operation or reliability monitoring of the bulk electric system. PJM's operators are required to take 32 hours of Emergency preparedness training per year and PJM provides the same level of training to member company operators. Thus, PJM and its member companies are in compliance with the increased NERC operator training requirements. PJM has one complete team of operators on training shift each week. This training shift is part of the normal shift rotation of operators, so operators are scheduled for training every sixth week. The training shift focuses on scenario based training using the power system simulator. This ongoing level of focus on operator training ensures that the PJM system operators are adequately

prepared to respond to system events. This level of training occupies 16% of each operator's work year which emphasizes the level of commitment that the RTO applies to training and preparedness.

Competent, well-trained operators can run a reliable regional grid because they work under a system of operational procedures and protocols that guide their actions in real time, based on sound analysis and system assessments. Although operators are the most visible aspect of the operational capability, a technical staff stands behind the operators providing analysis, documentation and support. The operators must have confidence in the tools used and the strength and depth of the support staff's skill is critical in building the confidence and trust in the tools. RTOs have the technical staff to support this type of effort, which ensures reliable grid and market operations.

Regional Planning Supports Reliability

One of an RTO's most important tasks is conducting regional planning to understand the reliability and economic needs of the regional grid and coordinate and direct the implementation of the regional plan so that needed infrastructure is built.

Like other RTOs, PJM works with its stakeholders to conduct holistic, integrated system planning. PJM's process examines and evaluates all system drivers and potential solutions to identify the most efficient, effective means to meet the reliability and economic needs. The PJM planning process identifies transmission system upgrades and enhancements to satisfy the operational, economic and reliability requirements of the PJM RTO. The process applies planning and reliability criteria over a five-year horizon to identify and resolve transmission constraints and reliability concerns. It considers a wide range of factors to ensure that all potential solutions, including generation, transmission, and demand side are integrated to produce a regional transmission system that supports robust competitive markets and reliable operations.

The PJM Transmission Owners' Agreement obligates transmission owners to build projects that are needed to maintain reliability standards and that are approved by the PJM Board. This assures that needed transmission enhancements are constructed on a timely basis to ensure transmission system reliability. Between 1999 and 2004, PJM's planning process has approved and directed more than \$1 billion in new transmission investments.

All of the adjoining RTOs work together to be sure that transmission expansion in one system is compatible with reliability and market issues in the neighboring region. Before the establishment of RTOs, there was little system planning to address regional flows and needs – utility planning addressed system expansion to connect

distant generators to loads, and to serve internal load growth. RTOs and companion multi-state planning organizations are the first to conduct regular, intensive planning to address region-wide and cross-regional needs.

PJM has committed to adapting the current regional planning process to resolve challenges that have been identified across the industry. PJM is developing methods to extend the current planning process out to 10 years and to adapt the transmission planning criteria to evaluate transmission infrastructure requirements based on the need to support wholesale market efficiency while maintaining and enhancing grid reliability criteria.

Generation Interconnection Planning Process

Another important responsibility for RTOs is to process requests for the interconnection of new generator facilities. This includes managing the queue of interconnection requests and analyzing the system impacts of each proposed generator. Generation developers are provided with the information necessary to directly interconnect their projects with the transmission system, as well as the network upgrades that may be required to maintain the reliability of the transmission system after the interconnection of their generation. This analysis is conducted on a non-discriminatory basis so that all new generation has an equal opportunity to interconnect with the transmission system.

PJM posts interconnection study results on the RTO website to allow all potential developers the opportunity to determine the optimal locations at which generation can be connected to the transmission system. LMPs give market participants information to determine where new generation projects will be most valuable. The combination of an open, non-discriminatory interconnection process and use of LMP has proven successful in attracting new generation to the market. Since the inception of PJM's generation interconnection process in 1999, more than 16,000 MW of new generation have been interconnected to the PJM system to enhance reliability and support robust, competitive markets.

All of the RTOs are wrestling with the question of how to ensure future resource adequacy so that future system needs will be met with both generation resources to supply energy for growing loads and demand-side resources that reduce or shape loads relative to supply to improve reliability. PJM has developed a Reliability Pricing Model which provides a holistic approach to evaluating resource adequacy requirements. This model provides a mechanism to evaluate infrastructure investment needs for transmission, generation and Demand response solutions on an equal basis to satisfy future reliability requirements and resource adequacy requirements.

Large Wholesale Markets Support Regional Reliability

The benefits that markets administered by RTOs can bring to consumers should not be viewed as substitutes for the reliability or as requiring consumers to make a trade-off between high levels of reliability and high levels of economic efficiency. On the contrary, the economic efficiency and information transparency of competitive wholesale electricity markets enhance reliability by ensuring that the “real” costs and benefits of actions taken within the system are revealed, and by creating a level of interoperability and information flows that provides system operators with important information about the “real time” and longer term reliability of the system.⁵

Economic Benefits

Large markets administered by RTOs produce substantial economic benefits for consumers. Consumers will realize benefits in systems in which the least expensive resources available to serve consumers are selected from a geographically broad area, and in which those resources are competing against one another for the chance to operate for every hour of the year. Larger market size means that, for any particular hour, there will be a wider variety of resources available to serve increments of load. Systems (such as PJM) that cover a wide geographic area can benefit from the diversity of conditions within that area: when one city broils in heat, and demands high levels of production, another within the market is likely to have lower demands, thus allowing the two together to be served by fewer resources than the sum of what each would require separately. Moreover, when systems combine their resources, the diversity of resources will likely increase as well, providing the system as a whole with hedges against shortages or price increases in any one fuel.

These benefits are most likely to be fully realized where an independent RTO administers a competitive market and enforces non-discriminatory practices. Vertically integrated and geographically separated systems may seek to favor their own resources. By contrast, the RTO’s sole market objective is to ensure that every resource has an equal opportunity to provide the energy and other products needed to supply customers’ needs and preserve reliability. Moreover, RTOs are indifferent to the kinds of resources that can be used: demand response, distributed generation, energy brought from remote locations over regulated or merchant transmission, energy produced by any fuel under any form of ownership or with any relationship to any other part of the system are all evaluated instantaneously against one another and selected based on their economic merit and their ability to provide the product

⁵ The FERC has recognized these advantages. For example, in FERC Order No. 2000, Notice of Proposed Rulemaking, Docket No. RM99-2-000, the Commission described the advantages of markets administered by RTOs for reliability (NOPR at 44), congestion relief (NOPR at 50), transmission planning (NOPR at 53), and limiting market power (NOPR at 63).

where and when needed. Under a competitive market structure, therefore, an RTO can ensure that, at any given moment, the entire system is operating at its highest efficiency, thus keeping the costs of electricity as low as possible for consumers within the RTO's footprint. The regional oversight of the RTO ensures that the economic efficiency that is realized through power transfers does not adversely impact regional grid reliability. The RTO economic dispatch model ensures that power transfers are managed within reliability constraints which in turn ensure that economic benefits are not created at the expense of reliability.

The structural independence of RTOs is an important element of ensuring these benefits. PJM operates under the guidance of an independent board of directors, who are not subject to the control of any one of the economic interests participating in the market; indeed, market participants are precluded from sitting on the PJM (and other RTO) boards. This structure ensures that the loyalty of the RTO is to the market as a whole, and to the economic efficiency that can be achieved for the citizens within the RTO territory, rather than to any particular pecuniary interest.

The effects of this degree of independence are apparent in the activity of the RTOs in promoting demand response and facilitating the introduction of "green" and other alternative forms of power into the system. Because RTOs have no financial stake in any particular form of supply, but are motivated only to ensure that the full economic value of what a supplier can bring to the market can be recognized by the participants. As a result, RTOs do not suffer the ambivalence about new sources of supply or the emergence of effective demand response that is sometimes observed in entities whose profits may suffer if their own production or "throughput" is reduced. Thus RTOs have moved to provide for new forms of demand participation in the wholesale market. PJM, for example, is currently proposing to extend its economic load response program; to allow demand to participate more extensively in capacity markets; and to give demand response a chance to capture the value it can provide in the reserve and regulation markets. With respect to renewable forms of generation, PJM (like the New England ISO) is implementing a system for the tracking of the attributes of generation, thus permitting the development of a liquid market for renewable resources that facilitates that various states' objectives concerning the supply portfolio. PJM has also developed operational and market rules that permit intermittent resources (like wind) to realize their economic worth without the penalties or impediments that characterize many systems outside RTOs. Finally, the RTOs, because of their regional scope and independence, can work as partners with the state commissions to ensure that the interests of the broader region can be accommodated while respecting the sovereignty and legitimate separate interests of the individual state. Thus PJM, like other RTOs, is facilitating the emergence of regional state committees (e.g. the Organization of PJM States) where policy issues of common regional interest can be reviewed and practical solutions can be developed.

The economic benefits of large RTOs have manifested themselves in a variety of ways. For example, within PJM:

- Generation is more efficiently operated under the competitive market than previously; the average generation forced outage rate has been reduced from more than 10% to approximately 7% since the market was put in place.
- PJM has been able to reduce its reserve margin requirement from 18% prior to market operations to 15% currently while maintaining the same reliability standards, which represents a significant savings to customers.
- A number of sources support the considerable savings that have been made available to PJM retail customers. According to the 2003 study from the Center for the Advancement of Energy Markets (CAEM), PJM customers saved more than \$3 billion from 1998 to 2003. PJM's independent Market Monitor notes, in the recently published PJM State of the Market Report, that the average price of a megawatt-hour of electricity in 2004, after adjusting for increases in fuel costs, declined by more than 4% when compared to the price in 2003. The Energy Information Agency of DOE reports that from 1995 to 2003 *retail* prices in RTO areas fell while prices in non-RTO areas rose.
- The implicit economic access of consumers to the broader wholesale market has directly resulted in generation production cost savings. These savings have been significant where utilities have joined RTOs. For example, AEP's study of the benefits as a result of its joining PJM revealed a nominal net benefit of \$188 million for the years 2004-2008.

RTO Markets Enhance Future Reliability

RTO markets provide important information about system conditions in a transparent manner that enhances future reliability over time through sustained economic signals. As described above, the integration of economic and operational information provided by markets administered by RTOs provide significant benefits to the real-time reliability of the system. In a closely analogous way, the same integration and information provides vital information – which might otherwise be masked – about how generation, transmission, and demand resources might best be used going forward to ensure that the efficiency and reliability of the system is continuously enhanced.

Without the transparency provided by LMPs, it may be difficult to determine whether an efficient mix of generation, demand and transmission has been achieved. For example, in the absence of transparent market prices, the dispatch of units “out of merit” (i.e. asking a more costly unit to produce more while a less costly unit is left

idle) may allow an operator to say that there is no transmission congestion in the system. This ability to mask the true cost of the system, often built into the more opaque operations of vertically integrated utilities operating outside of broader markets, is lost when markets are put into place. The reason is straightforward: when suppliers of generation see opportunities (in the form of higher prices elsewhere), they will try to sell their power where they will gain the greatest economic benefit. To the extent that not enough “cheaper” power can be brought into the area with higher prices, a constraint emerges, requiring those inside the constraint to pay a higher price than those outside and creating “congestion” on the system. While this congestion is revealed by the economic signals created by the market, all congestion has a reliability component in the sense that even economic congestion reveals that the resources available in a particular area are under more strain (either economic or in terms of their number and size) than those in the system as a whole. Thus, by identifying the areas in which economic congestion is emerging, the market gives a preview of areas where, if load increases or generation within the constrained area falters, reliability may be jeopardized.

As important as identifying areas where reliability may become a problem over time, markets also help provide both the incentive and the mechanism for resolving the reliability issues. An investor searching for a place to locate a new generator, for example, will be guided by the price “separation” that locational pricing models reveal. Similarly, a utility or merchant transmission enterprise will choose to build new transmission in areas where constraints have been an issue because new transmission in these locations can relieve or reduce the constraint and reap the economic benefit doing so. Finally, higher prices in some areas, again revealed by a market in which the prices reflect the operational characteristics and location of all available resources, will provide a stimulus for firms seeking to capitalize on the inherent value of demand side management to focus their efforts on areas that have been identified as “most” in need of such efforts.

This is not to say that RTOs have already successfully integrated all these possibilities into their markets. As recent litigation before FERC and discussions among stakeholders reveal, there is not yet general agreement on the particular manner in which the information created by markets can be translated into a successful market that will provide the right incentives for the full panoply of resources to anticipate (and not merely react to) future needs. Nevertheless, the structural independence of RTOs provides an ideal forum for exploring and evaluating the mechanisms for how long term reliability (and economic efficiency) can be achieved. The sole interest of the RTOs is to ensure that reliability is maintained and that the market works: RTOs do not benefit from the relative success of one firm, or one kind of resource, at the expense of any other. Moreover, only the RTOs have, at this point, the geographic perspective that precisely matches the geographic boundaries of the market. Thus, while a properly designed market will

provide the information, tools and incentives for ensuring both near and long term reliability, the uniquely evenhanded perspective of the RTO at the center of the market will help tease out, and bring to FERC for approval, the solutions that are likely to work best.

Large Scale markets provide economies of scale

Consumers of electricity seek both high levels of reliability and reasonable prices. Large scale markets administered by RTOs can help address these sometimes conflicting objectives by providing economies of scale, and thus lower costs per consumer, for ensuring reliability. This phenomenon is reflected in the data that show that while PJM has expanded during the past few years, and substantially increased the number of customers served by the PJM market and by the operations staff of PJM Interconnection, the cost of providing the market and operational services has continued to drop, and now stands at about 39 cents per MWh (equal to about 24 cents a month for the average residential consumer).

While RTOs strive to ensure that they provide their services at the lowest cost possible, there are significant inherent economies of scale and scope in RTOs that cover large geographic areas. For example, a substantial portion of an RTO's budget is for the software and hardware required to dispatch resources and monitor the transmission system; these costs do not increase proportionally to size; the cost per transaction, and per customer served, declines as the same system increases in size. Similarly, because all RTOs must have fully redundant systems, having one "extra" system to serve all or part of 13 states is obviously more efficient than having a separate "extra" system in each of the component utility territories.

Because operational costs in large markets served by RTOs can thus be reduced relative to the costs faced by their balkanized cousins, the savings thus achieved can be used both to reduce consumer payments for electricity and to improve reliability. In short, consumers in a large RTO get more for less.

Conclusion

FERC has recognized that wholesale markets, especially if they span a broad geographic area, can bring enormous savings to consumers. PJM's experience demonstrates that these savings can be achieved while enhancing, rather than diminishing, the reliability and security of the electricity system. The immense amount of operational data transparency that has been achieved through the PJM RTO market has made each market participant a partner in proactively preserving reliability by following the incentives that are created through locational energy price signals. Since the locational prices are a byproduct of the security-constrained economic dispatch, these prices are entirely consistent with reliable operation and

provide incentive not only for reliable real-time market operations but also for future grid reliability management.

The large scope of the regional RTOs has enhanced and accelerated development of advanced technology to increase the ability of system operators to proactively avoid unsafe and unreliable operating conditions while more efficiently operating the power grid. Interregional coordination among the RTOs has enhanced interregional data sharing which has substantively mitigated information gaps that contributed to the 2003 blackout.

Regional RTO markets have evolved to produce economic efficiency and enhanced reliability in short-term and mid-term operations. In the energy legislation that has been recently enacted, the DOE has been charged with identifying transmission corridors for upgrades that will address transmission congestion and increase the flow of power through regions. The regional RTO markets provide transparent regional information that will assist the DOE to directly address these issues in the coming years. PJM stands ready to support this effort and will continue to actively work to address the fundamental long-term infrastructure investment concerns that exist on a national level.

Reliability Risks during the Transition to Competitive Electricity Markets

**John P. Hughes, Vice President - Technical Affairs
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Introduction

The Electricity Consumers Resource Council (ELCON) is a U.S. association representing large industrial consumers of electricity. The organization was founded in 1976 to promote the development of coordinated and rational federal and state policies to assure an adequate, reliable, and efficient supply of electricity for all users at competitive prices. Since ELCON's inception, its member companies have represented virtually every segment of the manufacturing community.

ELCON is a long-standing advocate of competition in the electric power industry although we believe that the transmission system is an essential facility that must remain regulated. Owners of transmission facilities should be compensated by charging rates based on cost of service. ELCON believes that competition and reliability are mutually beneficial to the extent that a reliable grid is absolutely necessary to support competitive wholesale markets and that the potential innovation and product differentiation made possible by true, two-sided competition can only enhance reliability.

Nonetheless, ELCON has serious concerns that grid reliability may be at risk during the transition to competition because the widespread application of market-based rates is encouraging anti-competitive, opportunistic behavior before adequate market or regulatory safeguards are in place. Such behavior has the potential to test the limits of the reliability standards developed by the North American Electric Reliability Council (NERC), its successor organization, or regional reliability councils, jeopardizing the security of the bulk power system.

Examples of these risks include (a) strategic maneuvers of incumbent utilities to maintain market share, discriminate against potential competitors, or take advantage of indecisive federal policies; (b) unintended consequences of state restructuring policies that allow utilities to over-earn their revenue requirements; (c) unenforceability of NERC reliability standards [until such time as a new Electric Reliability Organization has been certified]; (d) gaming of flawed market designs and inadequate market power mitigation; and (e) financial distress of merchant generators.

These risks are of great concern to ELCON's members and other members of the industrial sector in the U.S. and Canada. Arguably, any one of these risks or a combination could trigger transmission loading relief incidents (TLRs), local outages, or another widespread blackout, yet all of these risks are preventable. In response to the August 2003 blackout, ELCON prepared a report summarizing the economic impacts of that event.¹ It is worth repeating from that report the following point:

From a public policy perspective—in the U.S. or Canada—it really does not matter if the total economic damages are \$4 billion, \$6 or \$10 billion, or anywhere in between. The point is that this type of event is unconscionable to the extent that a single utility's failure to properly trim trees is deemed the "root cause" of the August 14 Blackout (ELCON 2004).

ELCON members were severely impacted by the August 2003 blackout and share NERC's concerns that, until now, the failure of the U.S. Congress to enact reliability legislation was itself a continuing threat to reliability. As this paper will demonstrate, in the absence of the deterrent effect of mandatory reliability standards with penalties, and complementary market rules for mitigating generation and transmission market power, economic incentives exist that will encourage other forms of opportunistic behavior that may one day be the "root cause" of other outages. Regrettably, public concern regarding these risks to grid reliability may be seriously eroding public support for competitive electricity markets.

Strategic Maneuvers of Incumbent Utilities

Wholesale market designs in the U.S. are incomplete and bogged down in contentious independent system operator/regional transmission organization (ISO/RTO) stakeholder processes, ongoing proceedings before the Federal Energy Regulatory Commission (FERC), and a growing list of judicial challenges. Meanwhile, incomplete, loophole-laden market rules are encouraging anti-competitive, opportunistic behavior.

Incumbent utilities may be gaming the transition to competition by attempting to use outmoded and unenforceable reliability standards and practices as well as regional variances to preserve market share or thwart competition. They may also be taking advantage of FERC indecision regarding policy on ISO or RTO formation. For example, the native load exemption in FERC's *pro forma* open access transmission tariff (OATT) and other flaws in Order No. 888 may create opportunities for undue discrimination and barriers to wholesale competition that can affect reliability. In a

¹ TLRs are a rationing scheme developed by NERC to manage flows on significant transmission paths called "flowgates." TLRs are used only in the Eastern Interconnection and apply to both U.S. and Canadian flowgates.

recently initiated Notice of Inquiry on information requirements for available transfer capability (ATC), FERC said:

The lack of standardization and coordination of ATC cannot only result in unduly discriminatory behavior, but can also on occasion affect reliability. As the LTATF [NERC's Long-Term AFC/ATC Task Force] recognized, inaccurate ATC values can lead to Transmission Loading Relief actions [or curtailments in the Western Electricity Coordinating Council (WECC)] if they result in transmission flows that exceed line limits (FERC 2005a).²

In another example, on May 2, 2005, Northern Indiana Public Service Company (NIPSCO) filed a complaint with FERC against the Midwest ISO (MISO) and Pennsylvania-New Jersey-Maryland Interconnection (PJM) asserting that loop flows resulting from the integration of Commonwealth Edison (ComEd) and American Electric Power (AEP) in PJM were overloading NIPSCO's transmission system (NIPSCO 2005). In fact, within hours of AEP's integration, the MISO security coordinator called a Level 6 ("Emergency") TLR on the NIPSCO system. Prior to FERC approval of ComEd and AEP's proposals to join PJM, FERC had NERC review the reliability consequences of the integration, particularly with respect to the so-called "Swiss cheese" configurations of the two RTOs. NERC's Operating Committee determined that the integration would have no adverse impact on reliability. In light of the NIPSCO complaint, it seems clear that the process by which NERC performed its analysis of the ComEd-AEP integration may be flawed, and that the potential reliability consequences of the integration were not adequately revealed.

The decision by ComEd to join PJM and not MISO, thus creating a large hole in the middle of MISO's footprint, is controversial. Midwest utilities such as ComEd have traditionally had a fuel mix dominated by nuclear and coal-fired units. Under PJM's locational marginal price (LMP) dispatch rules and that region's greater reliance on natural-gas-fired capacity, higher-cost natural-gas-fired units "clear the market" in an increasing number of hours providing substantial windfall "infra-marginal" revenues to owners of nuclear or other lower-cost-based loaded units. This is a clear example of economic incentives effectively trumping good utility practices for operating the interconnected transmission system to ensure reliability.

² AFC/ATC is the NERC acronym for "available flowgate capability" and "available transfer capability." Both are commercial measures of the remaining capability of a transmission facility available for sale after all existing uses or commitments are accounted for.

Unintended Consequences of State Restructuring Policies

Beginning in the early 1990s, states with high electricity rates launched a series of initiatives to restructure their electric utilities. Stable fuel prices (helped by “\$2 gas”), declining interest rates, and the distractions caused by pending restructuring legislation gave many utilities good reason to avoid new rate-case proceedings. And one by one as states implemented various restructuring mandates, retail rates were typically frozen after a nominal reduction. Regulatory lag also works to the advantage of utility shareholders when a utility avoids new capital investments while undergoing aggressive operations and maintenance (O&M) cost-cutting measures.³

In testimony before a house subcommittee, former FERC Chairman Pat Wood said:

Utilities seeking to build new transmission face a number of hurdles. Most traditional, vertically integrated utilities with retail service obligations must go before their state commissions to seek retail rate recovery for any investment they make in new transmission. This can involve opening up all of their costs as well as their entire rate structure for reevaluation, a step few utilities desire. Often utilities are subject to retail rate moratoria, which can jeopardize their ability to recover any investment in new transmission from retail customers during the period of the retail rate freeze (Wood 2005).

Thus, state policies may create powerful economic incentives to reduce reliability-related maintenance costs (e.g., tree trimming), or to under-invest in T&D facilities necessary for maintaining reliability.

For example, on August 12, 1999, ComEd, which is now an Exelon company, experienced a major blackout in downtown Chicago and the nearby Westside neighborhood. The episode – the second that summer – was a major embarrassment to the company’s relatively new chief executive officer (CEO), John Rowe. In reaction to a growing political backlash resulting from the outages that at one time threatened the utility’s franchise, Rowe called the company’s performance “absolutely, totally unacceptable” and immediately appointed a committee to study the company’s problems and recommend solutions. The company’s state regulatory body, the Illinois Commerce Commission (ICC), also requested an investigation several days later. It should be noted that the state legislature had ordered the company’s rates cut by 20% and subsequently frozen beginning in 1997.

³ For example, some utilities adopted “predictive maintenance” in place of traditional “scheduled maintenance” as a basis for timing O&M expenditures. Under predictive maintenance, transmission and distribution (T&D) facilities are replaced based on algorithms that predict when failure will occur. Maintenance is then done “just in time” (Burns 2003).

On September 15, 1999, ComEd issued its report, *A Blueprint for Change*, which was filed with the ICC, other Illinois public officials, and consumer groups. According to the report's executive summary, "[t]he major findings reveal serious issues in the transmission and distribution system, especially in the areas of system maintenance, planning, and design" (emphasis in the original). In essence, the company had let its infrastructure deteriorate by a combination of under-investment and deferred maintenance.⁴

On June 8, 2000, the ICC issued the first part of its independent assessment of the ComEd blackouts, repeating the findings in ComEd's *Blueprint for Change* but in considerably stronger and more focused language. The summary of findings in the report said that ComEd:

...failed to budget enough money for necessary capital improvements and maintenance. Even ComEd's failures in the areas of load forecasting and planning can be traced to a corporate desire to minimize the money spent to improve the transmission and distribution (T&D) system. In many respects, ComEd was in a reactive mode of operation, often waiting for parts of its T&D systems to fail before taking any action and only attempting to improve the worst parts of its T&D systems (ICC 2000).

The ICC study provides some evidence that ComEd's unwillingness to properly maintain its infrastructure pre-dated 1997, the year in which the retail rate freeze took effect, and may have started in 1991, roughly the beginning of the recent era of industry restructuring and the same time at which many utilities began to cut costs in anticipation of competition. The infrequency of public scrutiny of the utility's revenue requirements and the likelihood that the utility was also over-earning its revenue requirement (with a rate freeze or not) were powerful economic incentives to continue to engage in this behavior.⁵

⁴ According to the ComEd report, in the fall of 1998, and after being on the job only since March 1998, Rowe reportedly questioned whether the company's T&D budget was sufficient to address customer needs and asked the T&D division to present a budget that allowed for "substantial performance improvements." The company expanded its three-year (1999-2001) capital budget for T&D improvements by \$307 million and its tree-trimming program by \$30 million—but it was too little, too late. After the August 12, blackout the company would spend an additional \$100 million for construction, operations, and maintenance in 1999 and would commit a total of more than \$1.5 billion in 2000 and 2001 (ComEd 1999).

⁵ The ICC study noted that in 1995, two-thirds of ComEd's management compensation incentives plan stressed cost reduction. And, in 1997, the company's incentive goals for the T&D organization had only one quantitative goal, which was a measure of O&M expense per customer (ICC 2000).

Unenforceability of NERC Reliability Standards

According to NERC, for the past few years, the Eastern, Western, and Electric Reliability Council of Texas (ERCOT) interconnections have been experiencing frequency excursions in the order of 50 millihertz or more. There is also a general trend upward in the number of such excursions.⁶ The causes of some, but not all, of the excursions are known.⁷ The known causes may highlight the fact that NERC reliability standards have not yet been developed to capture new generator operating practices that support competitive wholesale markets. The unknown causes are more troubling and have generated very concerned debate at recent NERC Operating Committee meetings.

In 2001, NERC General Counsel David Cook testified before the U.S. Senate Governmental Affairs Committee:

NERC is seeing **increasing violations** of its reliability rules. As I mentioned earlier, the grid is generally operated in a first contingency mode, that is, so that the grid can withstand the loss of its largest element and remain stable and secure. Last summer there were a number of instances where operators allowed facilities to remain loaded above their known security limits for extended periods of time, placing the grid at prolonged risk of major failure. Some entities have made the economic judgment that it is less costly to them to violate the rules than to follow them. We have seen entities improperly “leaning on,” or taking power from, the Interconnection, causing unscheduled and unmanageable flows and potential voltage problems. As the limits of the system are reached and transactions must be curtailed, we are beginning to hear suggestions to relax the reliability rules to allow higher flows to occur. In an interconnected system, however, taking increased risks to allow some entities to realize short-term economic gain affects not only the system where the limit occurs, but also all the systems in the same Interconnection. For example, in the 1996 outages in the Western Interconnection, customers far away from the initiating problems were interrupted for significant periods of time (Cook 2001) (emphasis in the original).

More specifically, the unenforceability of NERC standards encourages control-area operators that are part of vertically integrated utility holding companies to take liberties with the standards to discriminate against competitors (e.g., TLRs) or use the

⁶ See June 8-9, 2005 Operating Committee Agenda, Item 14 (“Interconnection Frequency”) at <http://www.nerc.com>.

⁷ For example, the “16 Hour On-Peak” and “8 hour Off-Peak” Day-Of and Day-Ahead products create predictable excursions.

balancing function for economic gain at the expense of other control areas in the interconnection. Merchant generators may also be encouraged to be loose with the rules if they know such acts are immune from regulatory scrutiny or financial penalties.

Gaming of Flawed Market Designs

The California power market debacle in 2000 is a landmark case study on how a flawed market design with inadequate market oversight and market power mitigation can lead to a “feeding frenzy” with catastrophic consequences to consumers and reliability. The important lesson from the California blackout that is relevant to this paper is that economic incentives will induce physical and economic withholding in the absence of adequate market rules and oversight. Both were severely missing from the California ISO (CAISO) and California Public Exchange (CAL PX) markets.

Since the California debacle, and in reaction to it and other market failures, FERC has been trying to promulgate market rules and regulations that provide the necessary oversight, monitoring, and mitigation. But the process has been slow and challenged by unrelenting “pushback” from the producer side of the industry. For example, a comprehensive rulemaking on market-based rate authority, of which a four-prong test for market power is to be the final outcome, is still in its earliest stage.⁸

FERC’s “organized market” paradigm for wholesale competition may also be creating unintended disincentives to new transmission investments necessary for maintaining reliability (ELCON 2005).⁹ The implementation of LMP-based markets was intended to provide a superior form of “congestion management” compared to previous approaches. Instead, congestion is only increasing in these markets. An additional complication for getting new transmission facilities sited and constructed is the lack of a bright-line test for distinguishing incremental investments that are needed for reliability from investments that are needed for economic reasons. This has created an ugly political battle over cost responsibility that is preventing both kinds of facilities from being built.

The markets of the organized markets are predominantly short-term in nature, i.e., most power that is not otherwise committed to some form of legacy contract is usually offered in the day-ahead and real-time markets. Liquid forward markets have failed to emerge. This unintended consequence of FERC’s market design paradigm increases the market’s vulnerability to reliability-related risk (ELCON

⁸ The four prongs are: (1) generator market power, (2) transmission market power, (3) barriers to entry, and (4) affiliate preference.

⁹ Technically, the term “organized markets” applies only to FERC-approved U.S. ISOs and RTOs. However, Ontario’s Independent Electricity Market Operator (IMO) has many of the features of the U.S. organized markets.

2005). Specifically, the organized markets impede the formation of liquid forward markets that may contractually bind generators to certain reliability-related performance requirements. Even though the transmission system in the organized markets is independently operated, market participants that are transmission owners can increase the revenues of their affiliate generators by maintaining (or even increasing) congestion.

In testimony before the senate in 2001, NERC's General Counsel David Cook warned:

...NERC is seeing **more congestion** on the grid, for more hours of the day. Last summer in the Eastern Interconnection there were substantial transfers of power from north to south. Cooler temperatures in the north meant that surplus generation could be sent to the south where the temperatures were hot and natural gas prices were high. On many days security coordinators had to invoke NERC transmission loading relief procedures to curtail transactions that were overloading transmission facilities between north and south. For generation sellers, these curtailed transactions resulted in lost business. Buyers were forced to replace these transactions with higher priced power, or in some cases, to cut off power to certain "interruptible" customers. In addition, what do not show up are the transactions that merchants or marketers decided not to engage in because of the likelihood they would be interrupted. Today, we know that those same transmission facilities are fully subscribed for the coming summer, meaning we could see a repeat of last year's pattern if we experience similar weather conditions and fuel prices (Cook 2001) (emphasis in the original).

FERC and the ISO/RTO market monitors have attempted to address the higher reliability-related risk of the organized markets by imposing real-time "circuit breaker" mechanisms and other out-of-market interventions. However, such mechanisms make the markets more opaque, complex, and vulnerable to new unintended consequences.

Financial Distress of Merchant Generators

Divestiture of utility generation [including reliability must-run (RMR) units] has put these generators outside the state regulatory oversight that has historically been more responsive than federal regulators to reliability concerns because local politicians confront the risk of outages more directly.¹⁰ Past FERC statutory

¹⁰ An RMR unit is a generator that a system operator can call upon when necessary to provide energy and ancillary services essential to the reliability of the transmission network, i.e., some generating units "must run" at

authority over reliability was questionable at best. While the new U.S. energy law attempts to give FERC such authority over reliability, there will still be a lengthy transition period before the full effect of the law is implemented and tested.

Many merchant owners of divested assets paid a substantial acquisition premium for the units. These owners assumed that many utility-owned generators in the competitive era would be uneconomical and therefore subject to retirement. Some of those owners also assumed that "\$2 gas" was more or less permanent. Both assumptions were wrong; the merchant sector in general is now financially distressed, and some companies have sought protection from creditors under U.S. Chapter Eleven bankruptcy rules. While the market rules of the ISOs and RTOs that operate LMP-based auctions are quite lucrative for the owners of baseloaded nuclear or coal-fired plants, they are not as lucrative for natural-gas-fired units on the margin, which has created other forms of opportunistic behavior.

RMR units have operating characteristics that make them more like transmission assets than are a pure merchant generator's assets. This makes it tough to "price" the product of RMR units in LMP markets so that the owners of RMR units can receive adequate compensation. FERC and the ISO/RTOs have been experimenting with a variety of out-of-market contracts and other methods to compensate RMR owners in response to threats by some owners of RMR units to retire or mothball their units unless they receive ample compensation. Fearing the dangerous consequences if such threats are carried out, ISO/RTO management is more than willing to give these owners whatever they want. In addition, some distressed merchant generators are claiming RMR status and attempting to bypass the market and get compensation through the more lucrative RMR contracts. According to Platts (2005), about 20% of the generation in the ISO-New England market either operates as RMR or is seeking RMR status.

For example, on April 29, 2005, Consolidated Edison Energy Massachusetts, Inc. (CEEMI) filed an RMR agreement with ISO-New England containing CEEMI's revenue requirement for providing cost-based generation service from the 107-megawatt (MW) West Springfield plant in central Massachusetts. Parties in the region that represent loads oppose the agreement because, unlike other RMR units, the West Springfield plant is not located in a "designated congestion area," "load pocket," or region facing a "well-defined transmission constraint." On June 10, 2005, FERC issued a deficiency letter citing the fact that CEEMI failed to demonstrate a need for the contract (MMWEC 2005).

certain times to protect the transmission system from voltage collapse, instability, and thermal overloading. The term is used in both the U.S. and Canada.

In another example, Milford Power Company LLC is also seeking an RMR contract with ISO-New England. The Milford plant is a recently constructed, two-unit, 555-MW, combined-cycle facility that uses natural gas as its fuel. It was built as a “merchant” base-load facility and began commercial operation in 2004. According to a party representing load:

The [Milford] project was financed and constructed in clear contemplation that it would operate within a competitive market for electric generation under market rules that expressly provided only for compensation for capacity under the then-existing regional installed capacity market (“ICAP”). The risk of investment in a merchant facility like Milford is borne by its investors. By contrast, Reliability-Must Run (“RMR”) agreements, which are regulated, “cost-of-service” contracts, shift the risk of investment away from investors and back to captive ratepayers (CMEEC 2005).

While such false claims of RMR status, if proven, are largely driven by the economic incentives of flawed market design, there is a real reliability risk associated with the growing aberrant behavior of distressed market participants.¹¹

Other Examples of Opportunistic Behavior

Other examples of some market participants’ opportunistic behavior that threatens the reliability of the grid are:

Barriers to Demand Response – There are widespread barriers in all markets (regulated or restructured) to demand response as an additional operational tool for maintaining reliability. Voluntary load shedding, especially during near-emergency conditions, is an economically and politically efficient means for rationing capacity.

Reduction in Grid Operator Control because of Data Confidentiality – Unregulated suppliers attempt to minimize grid operators’ access to operational data on the suppliers’ generators under the pretense that such information is market sensitive. As a result of these confidentiality practices, grid operators lack full information on all available resources even though this information is essential in an emergency when seconds count. In other countries with restructured power markets, merchant generators are required to be forthcoming with operational data (including market offers and bids) with no apparent sacrifice of market efficiency.

¹¹ During a severe cold spell in New England in January 2004, some generators with firm natural gas contracts sold their supplies on the spot market rather than produce power. The resulting increase in unit outages caused an electric reserve deficiency, prompting ISO-New England to urge conservation and issue a potential blackout warning (FERC 2005).

Failure of Market to Rebundle Generation and Transmission Services – Thus far, competitive suppliers in restructured markets have not offered rebundled generation and transmission services that capture the economies of scale and scope of the vertically integrated industry. The absence of rebundled services may lead to fragmentation of authority when grid reliability is on the line.

Proposed Solutions

On August 8, 2005, President Bush signed the Domenici-Barton Energy Policy Act of 2005 into law. Subtitle A in Title XII (“Electricity”) authorizes the certification of a new Electric Reliability Organization (ERO) in North America to establish and enforce mandatory reliability standards subject to FERC oversight (in the U.S.). The President is also urged to negotiate international agreements with the governments of Canada and Mexico to ensure compliance with reliability standards and the effectiveness of the ERO in the three countries.

Congress also gave FERC additional authority to police market power abuses and impose stiff penalties. The penalties are intended to be sufficient to deter harmful behavior and mitigate any economic incentive to breach reliability standards. With this new law, there is at least a reputable presumption that FERC now has both the authority and responsibility to ensure that market power is not exercised in the competitive wholesale markets for the sake of reliability and honest market operation.

But the enactment of these provisions is only an essential first step for addressing the concerns raised in this paper. Given that market rules and reliability rules are, for all practical purposes, inseparable, several additional actions are necessary at the federal level in the U.S. to address the transitional risks to grid reliability described in this paper:

1. The U.S. Congress directed FERC to complete within 180 days of the law’s enactment a rulemaking establishing the criteria for ERO certification. It is essential that this rulemaking preserves the intent of the law and is not used to preserve the fragmented lines of authority the currently exist between NERC, regional councils, RTOs and transmission owners. The development and enforcement of reliability standards must be done on a “top down” basis with plenary authority for both functions residing with the ERO subject to the oversight of FERC and its Canadian counterparts. Any deference or delegation of these functions must not be an excuse to preserve some market advantage or allow opportunistic behavior.
2. FERC should reform the market design of the RTO-administered organized markets to eliminate economic incentives to under-invest in reliability-related

facilities or to defer maintenance and other operating expenses related to reliability.

3. FERC should initiate a thorough investigation of the economic impediments to new transmission investments. This investigation should address why FERC's current incentives for new transmission investments – that have since been codified in the new energy policy act – are not effective. FERC should consider requiring as a condition to future merger approvals that the merged companies upgrade their transmission network to mitigate congestion. In addition, FERC should consider a condition of future approvals of market-based rate authority that the company upgrades the transmission network to mitigate any potential by the company to exercise market power.
4. States should review their policies and regulations to remove any disincentives to prudent investments in and expenditures related to reliability and demand response.
5. FERC should complete its ongoing rulemaking on market-based rate authority of which a four-prong test for market power is to be the final outcome. [The four prongs are: (1) generator market power, (2) transmission market power, (3) barriers to entry, and (4) affiliate preference].
6. Structural remedies such as the creation of stand-alone transmission companies, which minimize any incentive to sacrifice reliability for economic gain, should be undertaken.

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Ensuring a Reliable North American Electric System in a Competitive Marketplace

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Introduction

Maintaining the reliability of the North American bulk electric system depends on the complicated and technically sophisticated activities of balancing electricity supply and demand and managing the flow of electricity throughout North America's interconnected networks. These activities require close cooperation among and adherence to minimum standards by all network participants.

For almost four decades, the North American Electric Reliability Council (NERC) and its member regional reliability councils have worked in close cooperation with industry stakeholders to provide essential standards and guidelines to promote the reliability of North America's power grid under a voluntary system of compliance with reliability standards. Due to changes within the industry, the voluntary model of maintaining reliability is no longer adequate. A new model is needed to ensure the continued reliability of the electric system in response to the restructuring of the industry to accommodate competitive markets. This model must ensure that the system functions reliably regardless of market structure or the degree of competition that is introduced in any part of that system.

During the past 20 years, the transmission system has had to support increasing uses, partly as a result of the restructuring of the electric industry to support wholesale generation markets. Before the introduction of competitive markets, utilities voluntarily complied with reliability standards to ensure that the lights stayed on. Traditionally structured utilities saw that it was in their interest to comply with these standards and were able to recover the costs of compliance through regulated rates. In an increasingly competitive electricity market, however, cost recovery is no longer assured, thus straining the voluntary system of maintaining reliability.

In addition to changes resulting from restructuring, the grid has had to accommodate a significant increase in electricity demand during the past two decades without a corresponding expansion of the physical transmission infrastructure. Construction of new transmission has been inhibited by the uncertainty associated with financing and cost recovery as well as local resistance to siting and building new transmission facilities. In some areas of North America, increases in generating capacity have surpassed the ability of the transmission system to simultaneously move all of the

electricity that can be produced to where it is needed. Moreover, the increase in market-based electricity transactions flowing across the grid has increased grid congestion, which has resulted in the curtailment of commercial transactions because of insufficient transmission capacity. The results of all of these changes are increased loading on the system and tighter transmission operating margins.

The increased demands placed on the transmission system require the grid to be operated closer to its reliability limits more of the time than was the case in the past. Although operating closer to the limits of system capability does not necessarily threaten the reliability of the system, these conditions require that system operators have appropriate skills and training to maintain the necessary level of situational awareness to operate their systems reliably. Today's advanced analytical tools allow system operators to assess system conditions and maintain reliability even on a constrained system much more accurately than has been possible in the past. But maintaining reliability also requires system operators to understand and follow NERC and regional reliability standards at all times. If operators adhere to NERC reliability rules, the transmission system can be operated reliably regardless of the demands placed upon it. But it is clearly no longer sufficient to rely on voluntary compliance with those rules. To ensure reliability in the future, NERC rules must be mandatory for all users of the bulk electric system.

Developing a New Reliability Model

In 1997, NERC assembled the "blue ribbon" Electric Reliability Panel to recommend the best ways to set, oversee, and implement policies and standards to ensure the continued reliability of the North American grid in a competitive and restructured industry. NERC imposed no limits on the panel's recommendations.

The panel concluded that the introduction of competition in the electric industry and open access to transmission systems required the creation of a new organization with the technical competence, unquestioned impartiality, authority, and respect of market participants necessary to set and enforce reliability standards for the bulk electric system (Electric Reliability Panel 1997). The panel found the following:

- The voluntary system through which NERC and the regional reliability councils had ensured reliability for many years would not suffice in a restructured future where a larger, more diverse group of competitors would replace traditional, vertically integrated utilities.
- Reliability rules must be mandatory, enforceable, and applied fairly to all participants in the electric industry.

- An independent, self-regulatory organization that set and enforced reliability standards would be more flexible, more effective in marshaling technical competence, and more open to new technology than would a government agency or agencies, but the new organization would require general oversight, approval and backstop support from appropriate government agencies to ensure compliance with reliability standards as well as adequate funding.

The panel concluded that, because jurisdiction over reliability in the United States was not clearly defined, changing from a strictly voluntary to a mandatory reliability system would require federal legislation. In response to the panel's recommendations, NERC and a broad coalition of industry, state, and consumer organizations developed and advocated a legislative proposal to create a self-regulatory electric reliability organization (ERO) to develop and enforce mandatory reliability rules. That proposal was included in *The Energy Policy Act of 2005*, which was signed into law by President Bush on August 8, 2005.

Reliability Legislation and the ERO

The reliability section of *The Energy Policy Act of 2005* authorizes the creation of an ERO that spans North America, with Federal Energy Regulatory Commission (FERC) oversight in the United States. The legislation recognizes the international character of the grid by ensuring that Canadian and Mexican interests in the system's reliability are fully considered.

The legislation amends Part II of the Federal Power Act to add a new section 215 that would make compliance with reliability standards for the bulk electric system mandatory and enforceable. The legislation applies to the facilities and control systems necessary to operate an interconnected electricity transmission network and to generating facilities needed to maintain system reliability. It does not address facilities used in the local distribution of electricity.

Under the legislation, reliability standards that provide for reliable operation of the bulk electric system will be approved by FERC. The standards will include requirements for the operation of existing system facilities and the design of planned additions or modifications to existing facilities to the extent necessary to provide for reliability. The legislation does not include any requirement to enlarge existing facilities or construct new transmission or generating capacity. The overriding intent of the legislation is to ensure that the elements of the bulk electric system are operated within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of the system will not occur as a result of a sudden disturbance or unanticipated failure of system elements.

The legislation gives FERC jurisdiction over the reliability of the bulk electric system in the United States. For purposes of reliability only, FERC would have jurisdiction over all owners, operators, and users of the system, including state and municipal entities, rural electric cooperatives, federal entities, the electric reliability organization certified by FERC, and any regional entities that receive delegated enforcement authority.

The legislation states that FERC may certify one electric reliability organization to develop and enforce reliability standards. The ERO must:

- be independent of owners, operators, and users of the bulk electric system;
- provide stakeholders with fair representation in the selection of directors;
- ensure balanced decision making in ERO committees;
- provide reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing reliability standards and managing ERO affairs;
- follow fair and impartial procedures in ERO enforcement actions;
- equitably allocate reasonable dues, fees, and other charges among end users for ERO activities;
- file any changes to ERO rules of procedure with FERC before they take effect; and
- afford a rebuttable presumption that reliability standards proposed by an interconnection-wide regional entity are appropriate.

Before a reliability standard can become effective and enforceable, the ERO must file the proposed standard with FERC. FERC may approve the proposed standard if it determines that the standard is “just, reasonable, not unduly discriminatory or preferential, and in the public interest.” In making its decision, FERC must give due weight to the technical competence of the ERO or any regional entity organized on an interconnection-wide basis but cannot defer to the ERO for an assessment of the effect of the standard on competition. If FERC rejects a standard, it must remand the standard to the ERO for further consideration; FERC cannot modify the standard.

The ERO may impose penalties on entities whose operations affect the bulk electric system if, after notice and an opportunity for a hearing, the ERO finds that an entity violated a reliability standard that is currently in effect. Any penalty must bear a reasonable relationship to the seriousness of the violation and must take into account

any efforts to remedy the violation in a timely manner. A penalty may not take effect until after the ERO files a notice and the record of the penalty proceeding with FERC, which may affirm, modify, or set aside the penalty.

FERC may order compliance with a reliability standard and impose a penalty on an owner, operator, or user of the bulk electric system if FERC finds that the entity has engaged in, or is about to engage in, activity that violates a reliability standard. FERC may also take action against the ERO or a regional entity with delegated enforcement authority to ensure compliance with a reliability standard or any FERC order pertaining to the ERO or regional entity.

The ERO may delegate its enforcement authority in a particular area to a regional entity. The regional entity must meet the same criteria as the ERO, except that the regional entity may have an independent board, a balanced stakeholder board, or a combination balanced stakeholder and independent board. In addition, the delegation agreement between the ERO and the regional entity must promote effective and efficient administration of bulk electric system reliability.

Before a delegation agreement can take effect, it must be approved by FERC, which may modify the agreement. The legislation contains the rebuttable presumption that a proposal for a delegation agreement with a regional entity organized on an interconnection-wide basis promotes the effective and efficient administration of system reliability. FERC may include in its regulations a provision for directly assigning enforcement authority to a regional entity, consistent with the legislation's requirements for a delegation agreement.

The ERO must assess and periodically report on the adequacy of the bulk electric system; however, the ERO does not have the authority to set or enforce mandatory standards for resource adequacy. The legislation gave neither the ERO nor FERC the authority to require the expansion of generation or transmission to ensure resource adequacy.

The reliability legislation reserves to the states reliability matters related to the local distribution system. The legislation does not preempt state authority to take action regarding the safety, adequacy, and reliability of electric service within that state so long as the action is not inconsistent with a reliability standard. If a dispute arises regarding whether a state action is inconsistent with a standard, FERC would consider the matter and may stay the state action pending a determination.

The legislation directs FERC to establish a regional advisory body on petition from at least two-thirds of the states in a region that have at least half their electric loads served within that region. Each state is to have one representative appointed by the governor. The regional advisory body may give advice to the ERO, FERC, and the

regional entity on matters coming before them. FERC may defer to the advice from a regional advisory body if it is organized on an interconnection-wide basis.

FERC's implementing rule must include fair processes for identifying and resolving conflicts between a reliability standard and a function, rule, order, tariff, rate schedule, or agreement accepted, approved, or ordered by FERC that is applicable to a regional transmission organization (RTO), independent system operator (ISO), or other transmission organization. Until the conflict is resolved, the affected entity is to continue following its tariff or rate schedule. FERC must complete its implementing rulemaking within six months of enactment of the legislation.

The legislation requires the ERO to take appropriate steps to gain recognition in Canada and Mexico. It urges the U.S. president to negotiate international agreements with the governments of Canada and Mexico to ensure compliance with reliability standards and the effectiveness of the ERO in Canada and Mexico.

Until FERC implements its ERO rulemaking and approves NERC as the ERO, and until NERC gains corresponding recognition from regulators in Canada, NERC will continue to work with the regions, government, and industry to use all means possible to ensure compliance with reliability standards under the current voluntary system.

Maintaining Reliability in a Competitive Environment

In anticipation of federal legislation, NERC has taken a number of significant steps to implement the recommendations of the Electric Reliability Panel, including the appointment of an independent board of trustees; establishment of a compliance enforcement program; adoption of a fair, open, balanced, and inclusive standards development process; and revision of its committee structure to allow for full and open participation while retaining necessary industry expertise. These and other changes have positioned NERC to apply for and step into the role of the ERO with little change to its day-to-day activities or disruption to the industry with regard to maintaining reliability.

Functional Unbundling and the Functional Model

Historically, control areas were established by vertically integrated utilities to operate their individual power systems in a secure and reliable manner and meet their customers' electricity needs. Operators of traditional control areas balanced load and generation, implemented interchange schedules with other control areas, and ensured both supply adequacy and transmission reliability within their boundaries.

Beginning in the early 1990s with the advent of open transmission access under FERC Order No. 888 and the subsequent restructuring of the electric industry to facilitate competitive power markets at both federal and state levels, the functions performed by traditional control areas began to change to reflect newly emerging industry structures. One key change that resulted from industry restructuring and that had reliability implications was the “unbundling” of some reliability functions typically performed by a single, integrated utility; many utilities either were required or chose to unbundle their functions into separate generation, marketing, and transmission functions, or even into stand-alone companies.

Recognizing that control areas may no longer function as the only entities responsible for maintaining reliability across North America, NERC worked with the industry to develop a model that defined the functions necessary to ensure reliability in the changing marketplace, regardless of the market structure that was ultimately put in place. Under the NERC Functional Model, entities operating at the bulk electric level, such as vertically integrated utility control areas, RTOs, ISOs, independent transmission companies, and merchant generators must identify the reliability functions that they perform and register those functions with NERC.

Developing and Implementing Reliability Standards

One of NERC’s major initiatives following the 2003 blackout was a thorough revision and refinement of its operating policies and planning standards into a single set of reliability standards. NERC used the Functional Model to rewrite its standards, which were based on the control area model, as a single, comprehensive set of reliability standards that apply to all entities that perform the various reliability functions once performed by a single control area.

NERC implemented its revised reliability standards on April 1, 2005, which industry stakeholders overwhelmingly voted to approve earlier in the year. NERC also completed the first round of registrations under the new reliability standards, using the Functional Model as a guide. Registered entities are now monitored for compliance with NERC standards through the NERC and regional compliance enforcement programs. NERC is developing additional standards to address issues identified in the 2003 blackout investigation, including vegetation management and system operator training standards.

Ensuring Compliance with Standards

NERC established its Compliance Enforcement Program in 1999 to promote greater compliance with NERC and regional reliability standards under the voluntary system, and in anticipation of the reliability legislation that would make compliance with the standards mandatory and enforceable. The program is designed to

encourage all market participants to understand and adhere to the standards necessary to preserve the reliability of the interconnected bulk electric system.

The Compliance Enforcement Program assesses compliance for a select number of reliability standards each year. In conjunction with NERC, each region has implemented its own regional compliance enforcement program. NERC oversees each region's compliance review and enforcement process; each region is responsible for reviewing and enforcing compliance with its members. NERC and the regions continually strive to improve the program because of its essential role in ensuring compliance with NERC standards.

NERC publicly discloses all confirmed violations of its reliability standards after due process has been followed with the affected entities. In ensuring transparency, NERC must accommodate legitimate confidentiality concerns regarding market sensitive information, critical infrastructure information, and personnel information. In addition, NERC and the regional reliability councils provide fair procedures and due process to achieve fair decisions and guard against premature, incomplete, or inaccurate disclosure.

Compliance enforcement is separate from the review process. The results of the compliance reviews are forwarded to the compliance enforcement process, which administers awards for achieving compliance and determines the level of sanctions or penalties for non-compliance with NERC standards. Awards and sanctions for compliance and non-compliance, respectively, are administered under both NERC and regional enforcement processes. Absent legislative authority for enforcement, NERC has relied on simulated enforcement actions to sanction noncompliance with its standards.

NERC relies heavily on the regions to enforce the NERC standards with their members, including the administration of awards and penalties. Entities that are monitored under regional compliance review and enforcement processes are not subject to additional compliance reviews, enforcement sanctions, or penalties from NERC. Regional appeals and alternative dispute resolution processes are available to resolve issues associated with compliance actions. If resolution cannot be achieved at the regional level, NERC serves as the industry backstop to hear appeals and resolve disputes.

Taken together, the Functional Model, the revised reliability standards, and the compliance enforcement program greatly improved NERC's ability to monitor and assess industry compliance with its reliability standards both in the absence of and in anticipation of reliability legislation.

Implementing the Blackout Recommendations

The 2003 blackout prompted NERC and the industry to take additional steps to improve reliability. Since the blackout, NERC, the regional reliability councils, and their members have worked to strengthen reliability by aggressively and successfully pursuing both NERC and the U.S.-Canada Power System Outage Task Force recommendations to improve reliability. Many of these recommendations have been implemented, and the remaining ones are well on the way to completion (NERC 2005).

Immediately following the blackout, NERC required all reliability coordinators, control areas, and transmission operators to provide at least five days per year of training and drills in system emergencies for each staff person with responsibility for real-time operations. NERC is developing a program to improve the ongoing training and performance of system operators. The program is designed to ensure that all system operators have the training and expertise necessary to ensure reliability.

NERC implemented a reliability readiness program to audit all entities that have reliability responsibilities; the audits identify areas of excellence in operations and areas in need of improvement. This program does not measure compliance with reliability standards but is designed to ensure that entities responsible for reliability have in place the tools, processes, and procedures to operate reliably. NERC completed more than 50 audits of the largest operating entities in North America in 2004; the program will review all relevant entities on a three-year cycle.

In 2004, NERC adopted guidelines for reporting and disclosing the findings of readiness audits and compliance violations. This action committed NERC to disclose the results of NERC and regional reliability council readiness audit reports and compliance reports. NERC believes that such transparency is vital if stakeholders, regulators, and the public are to have confidence that NERC and the industry are doing all that is necessary to ensure a reliable bulk electric system. Disclosure allows NERC to shine a “bright light” on compliance violations in a way that was previously not possible and should help to further encourage industry compliance with NERC and regional reliability standards. Consistent with this principle, NERC posts on its website final readiness audit reports, summaries of compliance reports from regional reliability councils, and NERC’s own compliance activities. Since the third quarter of 2004, NERC compliance reports have included all confirmed violations of NERC and regional reliability council standards once investigatory, decisional, and appeal processes have been completed. The reports note each violation, identify the names of the organizations involved, and characterize the relative seriousness of the violations. Although disclosure reporting is a relatively new development, it will be possible to use the data that NERC

collected prior to the passage of reliability legislation to document changes in the level of compliance or noncompliance with reliability standards once the legislation is implemented and compliance with NERC standards becomes mandatory.

NERC regularly evaluates the effectiveness of the compliance program and incorporates recommended improvements each year. In 2005, NERC will publish four quarterly reports that disclose the identity of entities confirmed to have violated NERC standards, regional standards, or both. These reports will identify trends and focus on emerging problem areas in standards violations. Certain violations will be reported to NERC within forty-eight hours and communicated to the board-level Compliance Committee. A primary goal for the 2005 program is to promote consistency among the regional compliance enforcement programs. Consistency is necessary to ensure that participants are monitored and assessed equally across all regions. To accomplish this goal, NERC will continue to work closely with the regional compliance programs to identify opportunities to improve and promote consistency.

In addition to the initiatives discussed in this paper, NERC is working with the industry to assess, develop, and implement a broad range of technical improvements that will allow for enhanced system modeling, monitoring, control, and communications. NERC is also developing a program to assess the overall reliability performance of the bulk electric system over time. The cumulative effect of these activities will be to enhance reliability across North America.

Assessing the Role of the Regions

In 2005, the regional reliability councils completed a study on the role of the regions (NERC 2005a). The regions used the language in the proposed reliability legislation described above to establish the fundamental principles necessary for organizations that perform reliability assurance functions and services. These principles include: open and inclusive membership, fair and balanced governance, independence, compliance, and establishment of rational organizational boundaries.

The report found that all regions currently conform to the principles of open and inclusive membership and compliance. Most regions also conform to the governance, independence, and organizational boundary principles. Mitigation plans are in place in the Southeastern Electric Reliability Council (SERC) to conform to the governance and independence principles, and in the Southwest Power Pool (SPP) to address issues associated with independence. The East Central Area Reliability Coordination Agreement (ECAR), Mid-Atlantic Area Council (MAAC), and Mid-America Interconnected Network (MAIN) look to achieve full conformance through the creation of one large regional reliability council.

On June 15, 2005, ECAR, MAAC, MAIN, and the Midwest Reliability Organization (MRO) formed the ReliabilityFirst Corporation to create a new, larger electric reliability council in the mid-Atlantic and central United States. ReliabilityFirst's goal is to preserve and enhance service reliability and infrastructure security for the interconnected electric system in its region. Upon approval by NERC, ReliabilityFirst will replace ECAR, MAIN, and MAAC. After the formation of ReliabilityFirst, the MRO and its members may consider merging into the larger organization.

The key functions of ReliabilityFirst are the development of regional standards for reliable planning and operation of the electric system and nondiscriminatory compliance monitoring and enforcement of standards in its region. The formation of ReliabilityFirst is the next step in a consolidation process that began in late 2004 and that resulted in execution of a memorandum of understanding by ECAR, MAIN, MAAC, and MRO in May 2005. The target date for implementation of the project is January 1, 2006.

Critical Infrastructure Protection

Maintaining the security of the electric system against physical and cyber attack is another key component of reliability that has received increased attention since September 2001. NERC is the designated Information Sharing and Analysis Center (ISAC) for the electricity sector. NERC works closely with industry and government agencies in Canada and the U.S. to improve the overall physical and cyber security of the electricity sector against constantly changing threats.

NERC has created a compendium of best practices for protecting critical facilities against a spectrum of physical and cyber threats. The *Security Guidelines for the Electricity Sector* address topics such as vulnerability and risk assessment, business continuity, physical and cyber security, and protection of sensitive information. NERC adopted a temporary cyber security standard in 2003 and is working on a more comprehensive, permanent cyber security standard that will replace the temporary one.

Conclusion

The initiatives discussed in this paper represent significant steps that NERC and the industry have taken to improve reliability in a competitive and restructured electric industry. Taken together, these actions will go a long way toward maintaining the reliability of the bulk electric system. NERC and the industry recognize that, with or without legislation, we must do everything we can to ensure that the lights stay on.

Despite the progress being made on the reliability front, no one disputes the fact that compliance with NERC reliability standards must be mandatory and enforceable for

all owners, operators, and users of the bulk electric system. Now that the president has signed the *Energy Policy Act of 2005*, NERC can put the last piece of the reliability puzzle into place to ensure that reliability is maintained, regardless of industry structure, the level of competition, or the number or types of entities participating in the marketplace.

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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.

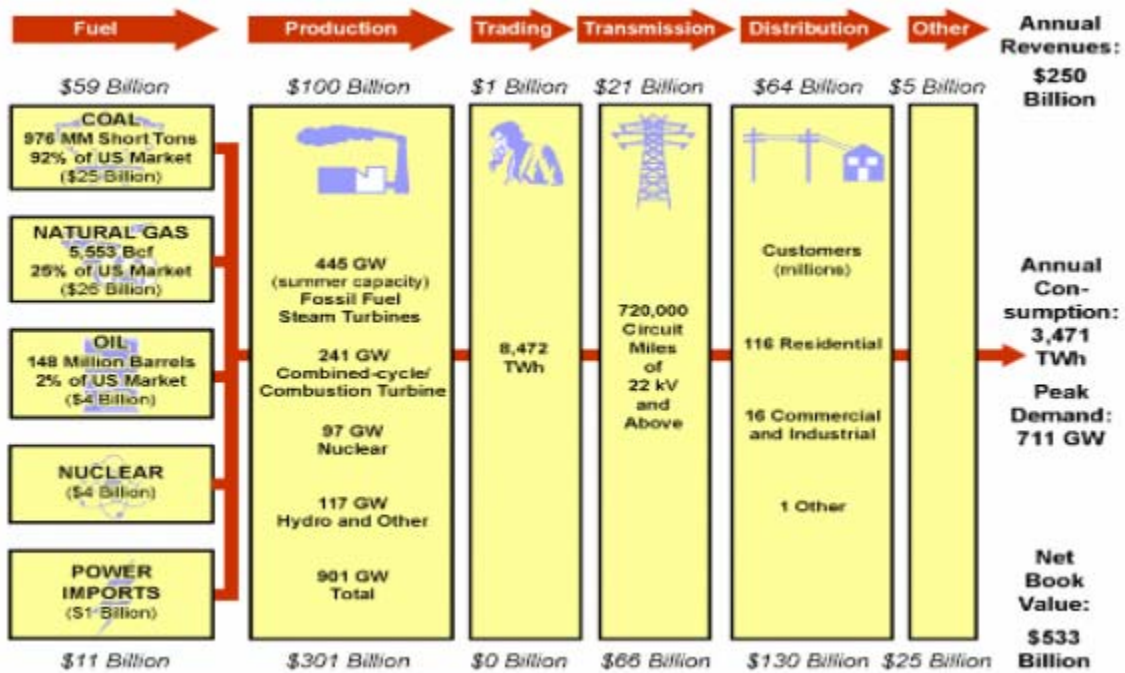


Figure 1. The U.S. electricity business value chain in 2002 (source: Cambridge Energy Research Associates)

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 (too 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.

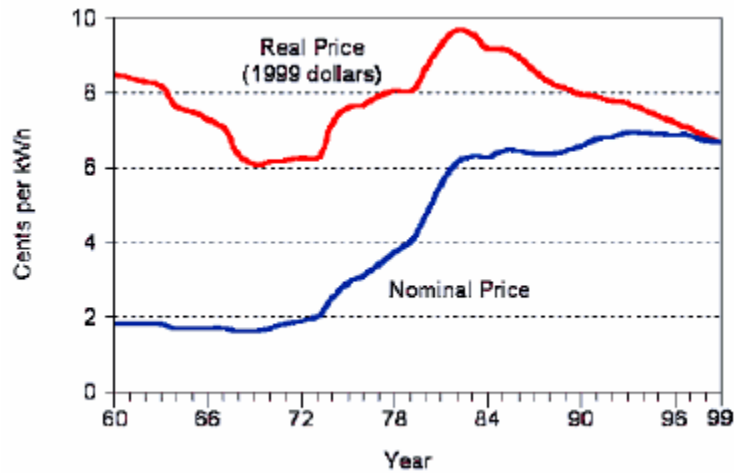


Figure 2. Average retail price of electricity sold by electric utilities from 1960-1999 (Source - U.S. Department of Energy, Energy Information Administration).

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 than 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 system 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

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 so it will survive to operate another time.”

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.

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. 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

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.

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 provisions³.

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.

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

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.

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.

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.

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

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 3 and 4). Both thermal and voltage constraints on transmission have been experienced in locations that were previously rarely congested.

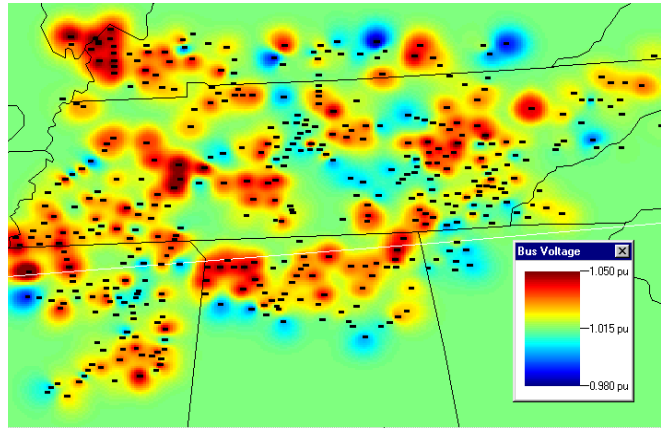


Figure 3. Normal peak-load voltage profile on the TVA system (July 1999)

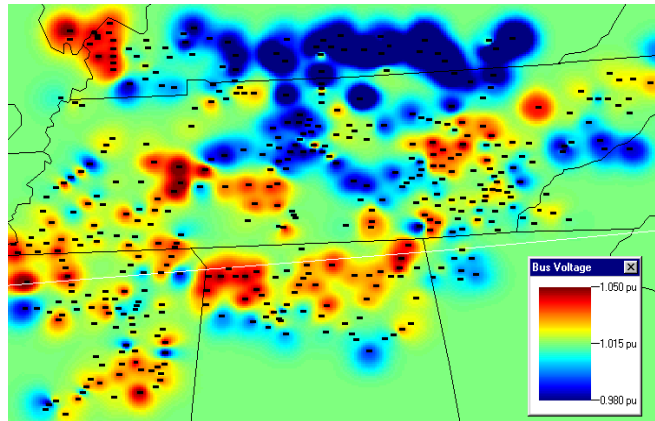


Figure 4. The voltage profile with 8,000 megawatts (MW) of loop flow (August 1999)

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 2.)

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.”

Table 2: 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%

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.

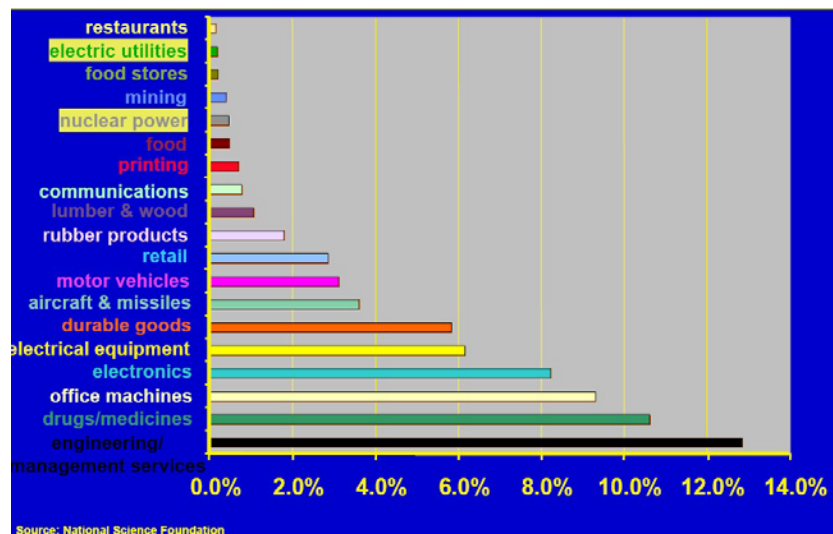


Figure 5. Research funding expenditures by industry (Source: National Science Foundation)

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 2005⁴. The NRC mission

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.

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 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 deployed⁵, 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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Alberta Electricity Industry Restructuring: Implications for Reliability

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Introduction

Alberta's electricity market has undergone significant restructuring during the past 10 years and will continue to evolve during the next five years. This paper discusses the restructuring of the Alberta electricity market and its implications for system reliability.

The remainder of this paper contrasts the restructured market and new institutional structures, roles, and responsibilities with the previous vertically integrated utility model. We discuss what has worked well and where there are still challenges that must be addressed to consolidate the benefits of restructuring without compromising reliability and safety. Finally, we summarize the key elements that should be considered to ensure that reliability is not negatively impacted by restructuring.

Description of the Alberta Market

A significant part of Alberta's large generation is located in the central to northern part of the province whereas the industrial and residential loads are located in the central to southern part of the province. Consequently, transmission plays a critical role in market efficiency and effectiveness.

Generation

- Current installed capacity is about 12,100 megawatts (MW) from 167 generating units.
 - More than 3,800 MW of new generation has been added since 1998, representing a 35% increase.
 - 50% of the existing generation is coal fired, 40% is gas fired, and the remainder is from hydro, wind, and biomass.
- Interconnections with British Columbia and Saskatchewan provide additional capacity of 800 MW and 150 MW respectively.

Transmission

- Alberta has more than 21,134 kilometers (km) of transmission lines and more than 519 substations; transmission lines are primarily 240 kilovolt (kV) for the backbone of the system and 138 kV for regional transmission
- There are significant planned or approved capacity additions including 500-kV upgrades in the main North-South corridor between Edmonton and Calgary. Recently approved projects add up to more than \$450 million with a total of nearly \$1.5 billion planned during the next 10 years.
- Major transmission facility owners (TFOs) are:
 - AltaLink – approximately 11,600 km of transmission lines, approximately 260 substations, serving 85% of Alberta’s population
 - ATCO Electric – approximately 8,900 km of transmission lines

Distribution

- Alberta has more than 165,000 km of distribution lines.
- Major Distribution Facility Owners are:
 - FortisAlberta – 57%
 - ATCO Electric –35 %
 - ENMAX – about 4%
 - EPCOR – about 3%
 - Other municipalities

Retailers

- Six retailers currently provide service to residential (three) and farm/rural electrical associations (three).
- Twenty-two retailers provide service to large commercial and industrial users.

Customers

- Peak demand in 2004 was 9,236 MW, up from 8,967 MW in 2003.
- Total customers in 2003 were about 1.34 million: 80% residential, 6% farm, 11% commercial, and 3% industrial.
- Total usage in 2003 was about 48,345 gigawatt hours (GWh): 16% residential, 4% farm, 23% commercial, and 58% industrial.

Market Liquidity & Price

- There were 244 Power Pool participants in 2004, quadruple the number in 2000.
- Total energy traded in 2004 was 130,520,430 MWh, which is approximately three times the energy load, demonstrating the liquidity of the market.

	1999	2000	2001	2002	2003	2004	2005*
Average Pool Price (\$/MWh)	42.74	133.22	71.29	43.93	62.99	54.66	45.90

* First-quarter average for 2005

Pre-Restructuring Market

Prior to restructuring of the Alberta electric industry, more than 90% of the province's electric power was generated, transmitted, and distributed by three vertically integrated utilities (TransAlta Utilities, ATCO Electric, and EPCOR). All aspects of their businesses were regulated – generation, transmission, distribution, and retail. Customers purchased a bundled service from whichever utility served their area of the province.

The provincial energy regulator, The Alberta Energy Resources Conservation Board (ERCB) provided general market oversight and dealt with environmental issues. They also were responsible for providing permits and licenses to construct and operate new energy facilities. The Alberta Public Utilities Board (PUB) oversaw economic regulatory matters including rate base, revenue requirement, utility earnings, energy prices, and rates.

The vertically integrated utilities planned and operated all segments of their businesses in their assigned service areas. This arrangement enabled integrated system planning; generation and transmission were developed together, which allowed for optimization of development sequencing. Economic dispatch was simple and transparent, accomplished through inter-utility cooperation and based on lowest variable cost.

Post-Restructuring Market

The provincial government began consultations on restructuring in 1990, leading to the Electric Utilities Act (EUA) in 1995 and subsequent amendments in 1998. These changes were directed at providing for customer choice and introducing competition to the generation and retail sectors. A competitive generation market began operating in 1996. Independent bodies, including the Power Pool and Transmission Administrator, were formed to enable market access and ensure the provision of adequate and reliable transmission facilities for participants. Licensing of retailers and codes of conduct were established in 2000, followed by the sale of Power Purchase Arrangements (PPAs)¹, which led the way to consumer choice for retailers commencing January 1, 2001. Transmission and distribution systems remain regulated under the jurisdiction of the Alberta Energy and Utilities Board (EUB) or other municipal authorities. In 2003, the Alberta government further amended the EUA, combining the Power Pool and Transmission Administrator to create a single independent system operator (ISO) to manage the power market, system operations, planning and load settlement.

¹ PPAs are one of the mechanisms used by the Alberta government to introduce competition to the supply of thermal electric power from generating units built during regulation (before 1995). The PPAs were auctioned in 2000 and gave buyers the rights to formerly regulated generating capacity. Unsold PPAs are managed by the Balancing Pool. In 2002, through the Market Achievement Plan, the Balancing Pool transferred about 2,000 MW of unsold PPA electricity capacity to market participants by means of short-term contracts.

Industry players altered their strategic directions in response to the opportunities that arose from changes summarized above. For example, TransAlta decided to focus on generation and divest itself of its regulated transmission, distribution, and retail. Many new players entered the generation business. In addition to creating a new level of functional independence of market participants, restructuring also resulted in significant changes in the system’s former integrated planning and operations. Figure 1 depicts the relationships among the TFOs, EUB, and the AESO.

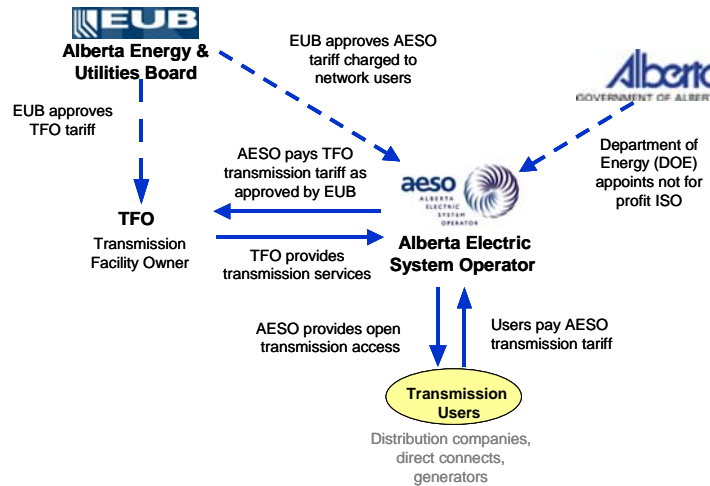


Figure 1. Transmission In Alberta

EUB – In 1995 the Alberta government merged its two independent energy regulatory arms (the ERCB and PUB) into one body, The Energy & Utilities Board (EUB). The EUB continues to provide regulatory oversight for the transmission and distribution sectors of the electricity industry. The EUB also plays a critical role in the review and approval of ISO facility needs applications and the TFO facility permit applications. In addition, the EUB oversees economic regulatory matters, including rate base, revenue requirement, utility earnings, energy prices, and rates.

AESO – The Alberta ISO is the Alberta Electric System Operator (AESO).

The ISO is tasked with guiding the planning and operation of key elements of Alberta’s electricity industry, including:

- Operation of a fair, efficient, and openly competitive power pool, including establishing and enforcing ISO rules to guide operation of the pool and financial settlements;

- Dispatch of electric energy in an economic manner to satisfy the requirements for electricity in Alberta ;
- Direction of the safe, reliable, and economic operation of the interconnected electricity system, including providing system access and transmission planning and arranging for system expansion and enhancement as needed ; and
- Regulation and administration of load settlement, including establishment of rules on load settlement processes, procedures, standards, and performance incentives.

Key Elements of Alberta’s Approach

Several elements of Alberta’s current restructured electricity market are critical to the efficient and effective operation of the Alberta grid.

Market Design and Supply

In a competitive market, generation developers decide to invest in new power plants based on forces such as price, market size, environmental and social issues, transmission system access, and a myriad of risk factors including regulatory and potential government intervention in the market.

Alberta’s Power Pool market features a real-time energy-only market with a single market clearing price for all buyers and sellers. No day-ahead market or capacity market exists in Alberta. Generators have open access to the transmission grid and only pay location-based loss charges; load customers pay postage-stamp wire costs. This market design encourages the development of low-cost generation, such as coal and cogeneration; however, this market presents a difficult environment for developing peaking capacity. The real-time energy-only market design is conducive to wind generation as wind generators have access to the Pool for their output without firm pre-delivery commitment. The Pool market is an ideal structure for the large-scale cogeneration operators in the Fort McMurray region as they can buy from the Pool when their load exceeds their generation and sell to the Pool when their generation exceeds their load. Finally, Alberta’s thermal-dominated system has a natural synergy with the hydro systems in British Columbia and the Pacific Northwest. Existing and future interties with those systems play a critical role in capturing these potential benefits.

Nearly half of the electricity in Alberta is currently generated by coal-fired plants, with increasing capacity fueled by natural gas, including highly efficient cogeneration. Renewable (hydro, biomass, and wind power) plants generate the remainder of Alberta's supply.

Alberta's competitive market has helped mitigate the increased cost of thermal generation (natural gas in particular). Competition has spurred innovation and efficiency as producers are facing competition for sales. Because the electricity market ensures that generators with the lowest bids are dispatched first, the result has been an increase in the diversity of the generation mix and downward pressure on electricity prices in spite of higher natural gas prices.

New generation investment in Alberta has kept pace with the needs of one of the fastest growing economies in North America. As shown in Figure 2, more than 3,800 MW of new generation has come on line since 1998, a capacity increase of more than 35%. In addition, generation from renewable sources, including hydro, wind, and biomass (wood) has increased by almost 45% from 900 MW to more than 1,300 MW.

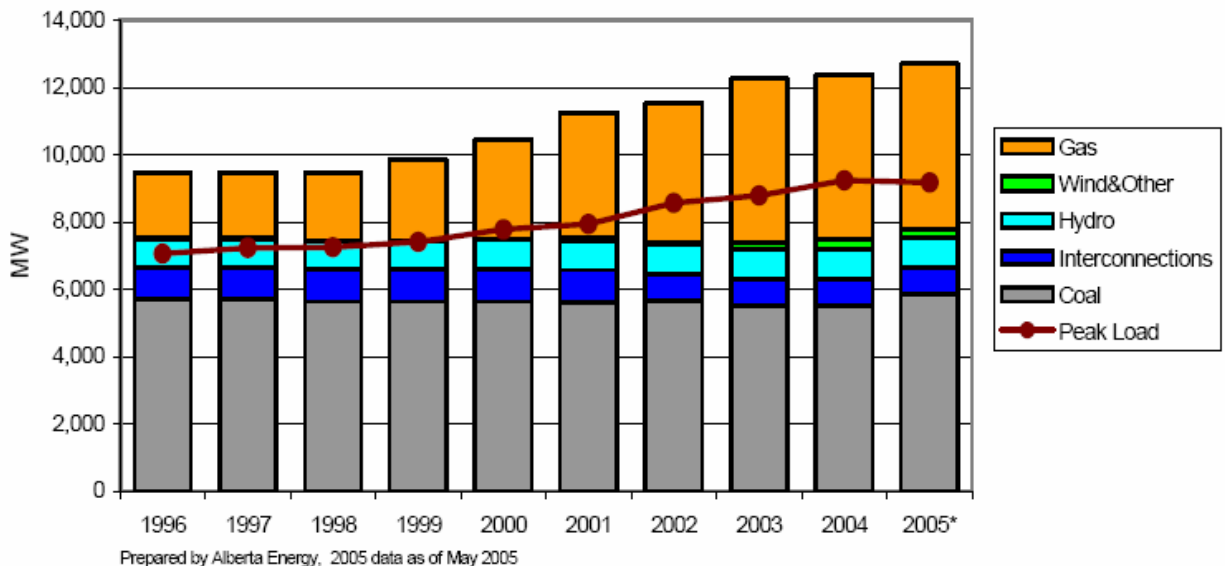


Figure 2. Growth in Alberta Installed Capacity

In a competitive market, there is no longer a centralized planning function to facilitate generation development at a given location and in a given timeframe. Instead, market forces dictate which generating plants will proceed and where they will be sited. Therefore, it is important that the ISO's transmission development plans be flexible, adaptable, and timely as well as economic and prudent.

Generators can develop major power plants in time periods as short as one to four years; however, the lead time for a major transmission expansion can be between five and eight years. Flexible and adaptable transmission development plans are needed to connect the most likely generation developments, to meet demand reliably, and to facilitate a competitive wholesale market. The ISO's role is to ensure that adequate transmission is available for new generation when that generation is ready to come on line and to serve growing demand for power in a reliable and timely manner.

Expanded Role of Transmission in the Market

After more than 20 years without a significant upgrade to Alberta's main transmission system, the province is positioned to move forward with much-needed transmission development. Transmission has a new role in the electricity industry beyond the historical role of safety and reliability; transmission will reduce customers' costs by increasing system efficiency, enhance market effectiveness, expand access to the lowest-cost generation, and protect customers from price volatility by accessing the most diverse, lowest-cost generation available.

To fully realize the goals of deregulation, customers will need to have access to the lowest-cost generation sources, reliance on expensive Transmission Must Run² (TMR) generation must be reduced, supply diversity and synergy through interconnections with other regions to be developed and barrier to transmission investment reduced.

In some circumstances, transmission will save customers more than the costs of the development through increased efficiency on the province-wide grid. In addition, the value of transmission improvements may exceed the value of grid efficiency savings by ensuring that the lowest-cost generation can access the market.

However, to enable critical investment in the transmission system, three barriers to investment have to be removed:

1. *Encouraging non-conflicted, independent transmission service providers.* Independent transmission service providers, have no internal competition for investment capital. They can therefore bring forward transmission solutions without the risk of

² Transmission Must Run (TMR) allows the ISO to manage transmission constraints by dispatching generation out-of-merit order. Typically, the ISO has to enter into a contract in which generators make capacity available for the ISO, from either existing or new plants, in exchange for pre-agreed compensation over the contract term.

adversely affecting the profitability of other business lines within the same organization.

2. *Creating clear, focused government policies on the development of transmission.* Policies like the Alberta Transmission Development Policy (TDP) help stabilize the development process, securing investors in all sectors of the industry.

3. *Strong regulatory leadership.* Regulators have the ability to create a stable investment climate by ensuring competitive equity returns for transmission facility owners, enhancing bondholder security, and collaborating with transmission owners to provide appropriate technological incentives. Regulators must recognize the vital new role of transmission and secure it for both today's and tomorrow's electricity consumer.

Electricity Policies

During the past two years, the Alberta government has codified important guiding principles and policy for transmission development. In late 2003, the government approved a new TDP to encourage timely, cost-efficient investment in transmission infrastructure. This policy was supported through a set of regulations under the EUA in August 2004.

Key directions from the TDP include the following:

- The transmission system should be planned to eliminate congestion under normal operating conditions.
- The ISO can initiate transmission facility additions for the purpose of facilitating a competitive market.
- Transmission Must Run (TMR) generation is not to be used as a substitute for transmission.
- Existing intertie capacity for imports and exports should be restored to their original design levels.
- Merchant transmission proposals to be dealt with on a case by case basis.
- Time limits were set for regulatory approvals, to shorten transmission lead time.

- The ISO is authorized to proactively design the system.
- Postage-stamp tariff should continue.
- A direct assignment process to be used for new transmission development, rather than a request for proposals (RFP) process.

This cornerstone document, along with regulations, provides specific direction to the ISO, EUB, and TFOs for hastening prudent development of the transmission grid. Recently approved transmission projects demonstrate the commitment to the policy. For example, the ISO has received approval for a new 500-kV transmission project (\$350 – \$450 million) to significantly increase transmission capacity in the North-South transmission network to enhance reliability, reduce losses, relieve congestion on the backbone of the Alberta grid, and improve intertie capability. The second major project is a \$90 – \$100 million upgrade to the Southwest system to secure reliability and facilitate the connection of up to 1,100 MW of new wind generation in that region.

In June 2005, the Alberta government released a document entitled *Alberta's Electricity Policy Framework: Competitive – Reliable – Sustainable*. This electricity policy framework paper also demonstrates the government's commitment to the reliability of the Alberta grid. Key points of this policy framework include:

- Interties play an important role in long-term adequacy; and the ISO is instructed to evaluate new interties in its 20-year outlook.
- Imports should be treated the same as intra-Alberta generation and be allowed to set pool price.
- The ISO is to develop long-term metrics to monitor supply adequacy with respect to generation and transmission status and appropriate generation reserve margin.

Alberta's policies recognize that transmission interconnections with neighboring jurisdictions are essential to a well-functioning power market as they support reliability, price stability, generation development, and continued economic growth in Alberta. Albertans benefit from these interconnections, which permit the import or export of power as needed. Additional intertie capacity may play a significant role in long-term adequacy by allowing greater exports from Alberta, which would

stimulate generation development in the province, placing downward pressure on Alberta electricity prices, and enhancing system adequacy.

Implications of Restructuring & System Reliability

Restructuring of the Alberta market resulted in a number of implications to the reliability of the transmission system in both the short and long-term. These issues are dealt with in the following sections.

Transmission Investment Lagging Generation Development

Very little expansion of the main transmission grid has taken place during the past 20 years, as shown in Figure 3. During the early stages of deregulation (1996), the primary focus was on generation. Utilities were still vertically integrated, and there was internal competition for capital. The focus of industry restructuring was on ensuring that new generation was built as there was a generation shortage at the time, and market prices reached unprecedented levels in 2000 and 2001. This situation was exacerbated by unclear policies and accountability regarding building of transmission, an issue which was given little attention until the generation market had been running for several years.

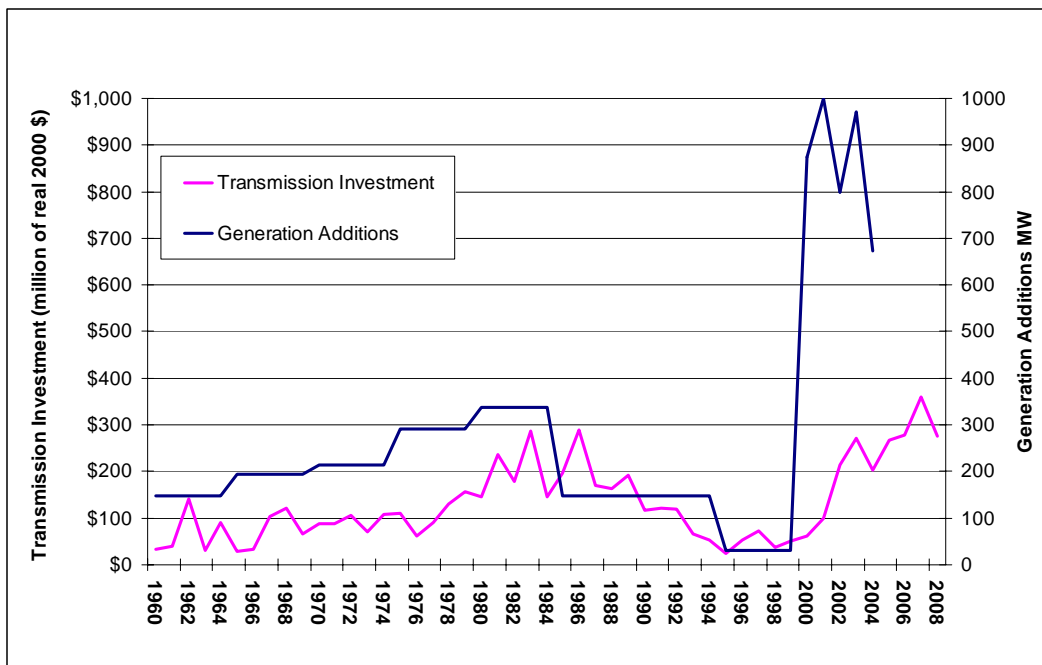


Figure 3. Transmission Lags Generation

The impact of inadequate transmission was not well understood from either a reliability or a market perspective, and the focus was almost entirely on cost with no regard for the benefits of transmission or market impacts of congestion. The debate often centered on locational marginal pricing and the need to ensure that appropriate economic tradeoffs were made between transmission and generation. Much concern was expressed that transmission would be overbuilt. This viewpoint did not recognize the significant costs of inadequate transmission. From a pragmatic standpoint, overbuilding is not an issue given the degree of independent oversight by both the ISO and EUB, the degree to which existing systems are in need of upgrading, and the challenges of siting new transmission with consequent long lead times.

Real-Time Reliability Issues

Generally speaking, the real-time physical operation of the power system – delivering power from generation to load – is more or less the same before and after restructuring. In this sense, restructuring has not had substantive impact on short-term reliability. However, restructuring has created a more complex environment in which operators have to deal with a wide range of operating conditions driven by not only the physical system but also by commercial transactions of both load and generation market participants. This situation has greatly increased the risk to short-term operational reliability. This risk is exacerbated by the fact that no major transmission upgrades have been undertaken during the past two decades and, as a result, the existing transmission system is being operated closer to its physical limit.

The current demands of a tight, complex system are a challenge for an industry that is accustomed to operating a transmission system that is not so close to its limits. In addition, customer expectations have increased, and reliable electricity supply has become more and more critical. There is little doubt that robust, mandatory, enforceable rules and procedures are essential and the enactment of reliability legislation by the US Congress is of assistance. If the operating rules are not clear and enforced then there will be a risk of pushing the system limits in critical situations.

Long-Term Reliability Issues

Long-term reliability issues include the need to eliminate congestion on the transmission system, the need to plan for transmission development rather than relying on the market to facilitate it, and the need to streamline the transmission development process.

Interplay Between Transmission and Generation

The elimination of congestion on the transmission system is critical to the development of the lowest-cost generation. The high cost of suboptimal generation being developed in response to transmission constraints is a substantial burden to customers that can be avoided if congestion is eliminated. Three examples in Alberta are:

- Restricted development of low-cost cogeneration potential in the Fort McMurray oils and area because of lack of transmission infrastructure;
- Development of uneconomic TMR and other Southern Alberta generation because of constraints on the North-South Transmission System; and,
- Exhaustion of the existing system capacity under normal conditions in Southern Alberta, which means that remedial action schemes will be relied on to support the operation of existing generation in that region in order to avoid overloads that could approach 175% under single-contingency conditions. Market participants have expressed strong interest in developing additional wind generation in this region; however, no further generation development can be accommodated until the transmission system is expanded.

The reliance on subsidized out-of-merit TMR generation needs to be eliminated in all but the remote regions of the grid. Using generation that runs out of merit to support the transmission system rather than building new transmission is a failed experiment in Alberta. TMR is not an effective or reliable substitute for transmission, has negative impacts on the market, and is not cost effective. TMR should only be used in very limited circumstances and should never be seen as a long-term solution. This has been recognized in Alberta and enacted in law through the Transmission Regulations under EUA.

Most stakeholders now acknowledge the expanded role of transmission in market effectiveness and efficiency; an enhanced transmission system is needed so that the most economic generation can access the market. Many projects can be justified on the basis of loss savings and improved efficiency alone. Building new transmission is key to increased reliability at a time of increasing customer expectations and dependence on electricity supply.

Planning

Comprehensive central planning that optimizes generation and transmission cannot take place in the restructured Alberta power sector. However, Alberta has learned through experience that the market alone cannot decide transmission development. In the initial stages of industry restructuring there was a tendency to believe that the market could “work it out,” which led to delays and uncertainty in the planning process. An example of this was the belief that locational marginal pricing would provide the right signals for the timing and location of needed generation. However, because of congestion and uncertainties, would-be investors in generation would not commit to long-term projects. Similarly, TFOs would not commit significant capital to construct transmission infrastructure based solely on price signals arising from locational marginal pricing. The Alberta experience clearly points to the need for proactive transmission planning that considers various generation scenarios.

Project Development

In Alberta, one of the approaches in opening up the market to competition was to allow any participant to compete for the development, ownership, and operation of new transmission in any geographic area. Alberta’s experience in using such an RFP process to develop transmission projects has proven that this mechanism is not appropriate for transmission projects located in existing regulated service areas. The RFP process created delays in the development of much-needed transmission additions, and these delays affected reliability. The RFP process was expected to encourage competitive bids that would lead to lower capital and operating costs and the entry of new market participants. However, rather than achieving these benefits, the RFP process negatively impacted reliability. TFOs were already bidding out 70% to 80% of the capital requirements of projects and were geographically positioned to be the lowest-cost operators, and no new market participants emerged. Alberta has abandoned the RFP process and returned to a process through which the projects are assigned to the incumbent regulated TFO.

Roles & Responsibilities

It is critical that the roles and responsibilities of agencies implementing policies and projects which can impact reliability are clearly delineated, do not overlap, and are well understood and accepted by each agency. Gaps in responsibilities or overlapping roles are a source of delay or inability to move forward on critical reliability initiatives. Unfortunately, there was a lack of clarity about roles and responsibilities during the initial stages of Alberta’s market restructuring. All stakeholders must have a fulsome opportunity to contribute views and input. Once the process of collecting input is complete, a decision must be made

expeditiously. Deference should be given to agencies that have the expertise and responsibilities, and no further detailed reviews should be required by other agencies. In a recent major facility hearing, Alberta policy makers were clear on this point: to ensure that reliability is protected, deference must be given by other agencies to the ISO on technical planning and design issues. The EUB continues to play a key role in regulating the TFOs and the ISO tariff as well as ensuring prudent costs of transmission. Increasing clarity regarding roles and responsibilities combined with clear policy direction and a more transparent stakeholder process are now creating the environment in Alberta in which implementing agencies such as the ISO can lead effectively.

Key Elements of Success

The following is a summary of key elements that should be considered when restructuring to ensure that reliability is not negatively impacted.

Need for Clear, Simple Transmission Policy

The Alberta TDP, which, among other things, mandates the elimination of congestion is a good example of a clear, simple, pragmatic policy. The TDP and the supporting regulations [Alberta Department of Energy, Transmission Regulation, 2004 Section 24 (a)] indicate that in reviewing the Need Application, EUB must “have regard for the principle that it is in the public interest to foster (i) an efficient and competitive generation market, and (ii) a transmission system that is flexible, reliable, efficient and preserves options for the future.”

Policies must clearly articulate requirements including eliminating congestion, avoiding use of TMR as a surrogate for transmission, and putting a time frame on the review and appeal process so that applications are handled expeditiously, allowing stakeholders to have strong input but ultimately ensuring that a decision is made in a timely manner. Timeliness of policy direction is critical during restructuring so that delays in needed transmission development, as happened early on in Alberta, are avoided. In an optimal situation, the transmission policy would lead the restructuring process.

Well-Coordinated Roles and Responsibilities

It is important to ensure that no overlaps or gaps exist among implementing agencies and market participants. The agency or market participant best able to effectively carry out an activity should be tasked with the responsibility and given deference to carry out this task. For example, the ISO has the expertise to perform technical review and planning for standard load and supply interconnections. Review of the technical merits by other agencies has little value. The regulator has a key role in overseeing costs and landowner and environmental issues. Well-articulated roles and responsibilities are needed to ensure that all agencies are aligned.

Balancing Stakeholder Concerns with the Need for Critical Decisions

Stakeholders must have an appropriate opportunity to provide input and express concern. However, stakeholder concerns and lack of consensus cannot be an excuse for lack of decision making. Consensus is rare, but critical decisions must still be made in a timely fashion. When the broad public interest is at stake, timely decisions are needed, in spite of lack of consensus, to capture cost-effective opportunities and avoid impacting the reliability and security of electricity supply.

Planning Requirements in a Competitive Market

Planning a transmission system where a competitive generation market exists requires walking a fine line. Planners cannot take on a traditional central planning role and make decisions about which generation will go forward and where it will be located. Rather, planners must develop a proactive plan for adequate transmission to enable the marketplace to function effectively. Consequently, planners must make some assumptions about where generation is likely to develop based on fuel source locations and high-level generation economics in order to determine the general location and sequencing of generation development to manage the long lead times of transmission. Shortening transmission lead times, and in particular the time required to obtain regulatory approvals, is a positive step in helping address the issue.

Regulatory Balance and Certainty

Given the need for large capital investment to expand inadequate transmission systems, the ability to attract capital is critical. Rates of return must be competitive with those of other jurisdictions and industries. Regulators must find the right balance between cost to customers and broader market benefits. Consistent, fair treatment from a regulatory perspective is critical to both investor confidence and

customers. Minimizing regulatory lag and facilitating negotiated tariff settlements and incentive-based regulation are positive steps.

No Congestion

A key issue is how to address congestion. One approach, which has been tried in some jurisdictions, is to implement a sophisticated and complex congestion management scheme. Another approach is to build transmission to eliminate/avoid congestion. Alberta has chosen the latter. This approach improves reliability, removes a key barrier to generation development, and is critical to enabling a successful restructured market. Alberta's policy is to eliminate 100% of congestion under normal operating conditions and 95% of congestion under abnormal conditions. Overall, Alberta has recognized that transmission is a low-cost, high-value proposition when considering both customer costs and reliability.

Conclusions

In the short term, although a complex and tight transmission system has certainly increased the risk of outages, restructuring has not had substantive impact on the real-time operations of the Alberta grid. In the long term, the question of restructuring's impact on reliability remains unanswered. In Alberta, restructuring initially resulted in a delay of new and required transmission, so that transmission has lagged significantly behind the new generation that has been added to the system. The result has been that the transmission system is operating very close to its physical limits with little or no margin for error. Although experienced operators have kept the system running, the risk of decreased reliability or outages is greater than ever before, and much-needed transmission upgrades are still several years away.

Alberta's current policy framework provides the direction and impetus to expeditiously address this heightened risk. Alberta has embraced the fact that transmission has a new role in the electricity industry beyond its historical role in safety and reliability; transmission reduces customers' costs by increasing system efficiency, enhances market effectiveness, expands access to the lowest-cost generation, and protects customers from price volatility by allowing access to the most diverse, low-cost generation available. Alberta has recognized through experience that transmission is a low-cost, high-value proposition in a restructured market. Recent facility approvals are evidence of this recognition being translated into reality. Enhanced and clarified planning roles for the ISO mean that Alberta is now poised to enable a proactive planning approach for transmission.

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Sinister Synergies: How Competition for Unregulated Profit Causes Blackouts

John Wilson

Executive Summary

Because the U.S.-Canadian Power System Outage Task Force did not address the primary underlying cause of the August 2003 blackout – deregulation (the pursuit of unregulated profit) – this paper is written as a first step toward a major study, one that addresses the effects of deregulation on reliability, as recommended in the Task Force's final report. Rather than focusing on the underlying cause of the deplorable state of the electricity system, the Task Force reports addressed only some of the low-level symptoms.

This paper is an overview of a large, very important issue: how unregulated profit reduces electricity-system reliability. The paper discusses the make-up of the electricity system and the system's importance to our security, safety, health, and economic well-being. The paper also points to what makes the system unreliable. It is important to keep in mind that the electricity system, unlike other systems, can fail nearly simultaneously across large parts of the continent and must, therefore, be treated prudently.

Although deregulation works well in some areas, leading experts, theory, studies, and experience show that the electricity system is not one of them. In March 2004, Former Canadian Deputy Prime Minister John Manley's Ontario Power Generation Review Committee stated, "We cannot rely solely on markets to solve our problems: no jurisdiction in the world had ever done so successfully." Surveys by the South Korean Tripartite Commission (government, labor, and business), Senior Research Fellow Steve Thomas, and Dr. Mark Cooper all support this assertion (Cooper 2003, 2002; Thomas 2004, 2004a, 2004b, 2003).

Trying to force unregulated profit into the electricity system will over time ruin the system and result in much higher prices and more blackouts.

A deregulated environment pushes producers to focus more on the short term and high returns than their regulated counterparts do. Higher costs and the need for greater profits have pushed deregulated power producers to cut costs drastically and to invest where high, short-term returns are more likely rather than focusing on reasonable long-term returns with reasonable cost savings and reliability. In

addition, deregulated electricity markets with their complexity, bidding, inelasticity, peakiness, etc. afford participants many opportunities to manipulate, game, and cut corners to increase profits. Higher costs and the need for higher profits combine with deregulated market conditions to provide both motive and opportunity for a culture of bad behavior. This bad behavior has cost consumers billions of dollars and resulted in increased blackout risk.

This paper demonstrates that we need a major study, such as that recommended by the Task Force, to examine what has happened in deregulated and regulated environments and also in situations where we can look at electricity systems both before and after deregulation.

Allowing the pursuit of unregulated profit in our electricity system causes major problems, including: changed focus, reduced resources, increased complexity, decreased planning and coordination, reduced transparency, on-the-fly implementation, and conflicting interests. These factors increase both the price of electricity and the risk of blackouts for consumers.

Changed Focus

Our electricity system used to be driven primarily by reliability, low cost, and regulated profit. During the past 15 years, unregulated profit has become the driver for large parts of the system. This has motivated participants to focus more on short-term goals and has resulted in reduced cooperation among them.

Reduced Resources

In deregulated parts of the electricity system during the past 15 years, there has been a *prima facie* reduction of money, people, knowledge, training, maintenance, rehabilitation, replacement, research, and the like where they are most needed. We can readily see that these issues demand investigation.

Increased Complexity

In deregulated environments, electricity supply and transmission become much more complex than in regulated ones. There are more participants (generators, retailers) and more transactions (bids, contracts, pools, futures, reserves, etc.). The rules for such situations need to be extensive and they are. Unfortunately, they are inadequate for preventing manipulation, gaming, and corner cutting.

Decreased Planning and Coordination

There is a large increase in complexity in deregulated systems compared to regulated systems because of increased numbers of participants, transactions, and relationships. This increase requires a much greater degree of planning and coordination to achieve the harmonious behaviour needed for the same level of reliability that can be achieved in an equivalent regulated system. In deregulated markets to date, this additional planning and coordination has not been forthcoming.

Reduced Transparency

Motivation and opportunity contribute to bad behavior and reducing the chances of getting caught greatly exacerbates the situation.

Regulated electricity companies are compensated for their investment and performance by regulators using rate hearings with interveners. These companies' costs are examined and their programs are explored and questioned. Regulated companies are much less likely than deregulated ones to take large, inappropriate risks because regulated companies are striving to make reasonable returns rather than rolling the dice for big profits. In addition, they need to demonstrate their concern for reliability and to justify costs.

Regrettably, deregulated companies do not have to justify prices or explain costs to the public. This allows individuals within these companies to take inappropriate risks and/or ignore reliability for personal or company gain. They can bet to win big and escape with the cash. Mergers and acquisitions, asset sales, bankruptcies, and movement of executives from one company to another increase the chances that the problems created by those who take risks will have to be handled by others. Unfortunately, at the end of the day, consumers are on the hook for this bad behavior because neglecting reliability over time increases prices and blackout risk.

On-the-Fly Implementation

Using complex systems in new situations without appropriate testing, pilot projects, risk management, gradual implementation, and backup procedures is a recipe for failure.

There is no one standard for a deregulated system. Everywhere deregulation has been introduced, it is unique. In addition, all deregulated systems have been radically changed over time. Britain is an example. After more than 15 years, the

British are still making radical system changes in response to big problems that keep arising in their deregulated power system. Thomas details the history of this ongoing fiasco in his 2004 paper “The British Model in Britain: Failing Slowly.”

Conflicting Interests

Individual electricity suppliers can dramatically increase their profits by reducing supply. Although motivation, opportunity, and a lack of transparency can lead suppliers to maliciously manipulate the system, there are also cases where a supplier's justifiable self-interest can make this happen. This occurs when there is a direct conflict between the common good and a supplier's desire to both protect an investment and increase profit.

For example, there are usually many reasons for either taking a generator out of service or leaving it in service. Repairing damaged equipment as quickly as possible prolongs its life and protects the investment in the equipment. When this is done during periods of peak load, not only is the investment protected but profit for operating generators is also driven much higher.

In a deregulated system a supplier may err on the side of self-interest and shareholder profit. In a regulated system the primary supplier often errs on the side of protecting overall electricity reliability if the risk of equipment damage is not too great.

Sinister Synergies

This paper highlights some of the effects of deregulation on electricity system reliability and demonstrates that there are situations in which the pursuit of unregulated profit can increase blackout risk. The effects of deregulation produce a sinister synergy – an overall blackout risk that is greater than the sum of the risks produced by each component.

When you don't know what you're doing and don't have enough resources to do the job, things can go from bad to worse. If you're also being pushed to quickly grab big profits, then there is a significant possibility that big problems will occur.

Conclusions and Proposals

We need to recognize how important the electricity system is, what the consequences of its failure are, and what is needed to keep it reliable, i.e., blackout-resistant. Like

the National Aeronautics and Space Administration (NASA), we need to put a hold on launches that can't be carried out safely because, in addition to the immense economic damage a blackout causes, it puts lives at risk just as a NASA launch does. I recommend that we put any further deregulation initiatives on hold until we have a better and more detailed understanding of how deregulation is really affecting our electricity system. Only then can we make reasonable decisions about the direction in which we should be moving.

I propose that, to understand the effects of deregulation, an independent investigation, as recommended in the Task Force's final report, be carried out. Only through a broad and in-depth look at deregulation and how it affects our electricity system can we understand and then address this important issue.

Introduction

I am writing this paper for the U.S.-Canada Power System Outage Task Force study on competition and reliability because the Task Force has not yet addressed the primary underlying cause of the August 2003 blackout. Unfortunately, the papers that the Task Force has invited and the workshops it has held also fail to adequately address this cause (Campbell et al 2005).

However, I hope the Task Force's study of this issue will be a first step toward establishing an adequate investigation of both the primary, underlying cause of the August 2003 blackout and, more generally, of how competition for unregulated profit increases blackout risk. I hope we will begin to understand the increased blackout risk that the pursuit of unregulated profit has introduced to our electricity system.

Our electricity system is one of the most complex creations ever made by man (Hirsh 1991). It is composed of large numbers of people, equipment, organizations, and institutions located throughout Canada and the United States. This system supplies the lifeblood of our society. It operates under changing electrical loads and in difficult environments. When it fails and blackouts occur, some people lose their lives and others their livelihoods, and the economy sustains overall damage.

Today, our electricity system is like a house – a rundown house with used paint cans and rags in the corners. On a hot day, a fire starts in a pile of rags, and a defective smoke alarm doesn't work. Serious damage results. The question asked is: "What was the cause?" Was it the rags, paint cans, hot day, and defective alarm, or was it what put the house into such deplorable condition? The primary, underlying cause of the

damage is the reason that the house was in such a poor state. This cause needs to be addressed if we want a more fire-resistant house.

Our electricity system is run down because of competition for unregulated profit. Instead of working to keep our electricity house in good condition, system participants have been chasing big, Enron-sized dollars. This situation is an unprecedented change from that of previous decades in both the U.S. and Canada when regulated profits were based on investment and performance, and participants were focused on providing low-cost, reliable electricity.

Unfortunately, the word "deregulation" – another name for unregulated profit – appeared only once in the hundreds of pages of the interim, final, and follow-up reports of the Task Force. In detailing causes of the August 14, 2003 electricity blackout, the reports took no notice of the fact that the blackout occurred in the Northeast U.S. and Ontario, the part of North America that is most deregulated. Instead the reports claim that phenomena such as human error, untrimmed trees, and lack of training blacked out electricity to almost 50 million people, but fail to explain what led to the human error, untrimmed trees, and lack of training. In addition, the reports neglect to mention the warnings that governments received about the blackout risks of deregulation (from, for example, the North American Electricity Reliability Council) and ignore the conflicts of interest of Task Force Electricity System Working Group members (as I noted in my previous presentation to the Task Force) (AP 2003; NDP 2003; Wilson, 2003).

Although these workshop papers can help us begin to look at how the pursuit of unregulated profit reduces electricity reliability, they cannot take the place of a thorough independent investigation, as recommended in the Task Force's final report and in this paper. Only through a broad and in-depth look at deregulation and how it affects our electricity system can we address the critical question of deregulation's effect on reliability.

Today, many people in government and in energy companies who make decisions about electricity are not fully aware of how the electricity system functions, how important it is, what the consequences of failures are, and what is needed to keep the system blackout-resistant. This understanding is necessary for making good decisions.

This issue is too important to our security, our safety, our health, and our economic well-being to simply point the finger at low-level problems, have a few papers written, and hold two workshops. We need to radically reduce the risk of future

blackouts. By thoroughly investigating the detrimental effects of electricity deregulation, we can take the first step toward understanding and addressing the problems it causes. We need to examine the bad behavior and conflicts of interest that the pursuit of unregulated profit brings to our electricity system.

Because of the size of the issue I am addressing, this paper can be only an overview of how competition for unregulated profit reduces reliability. The main conclusion is that the evidence clearly indicates the need to investigate the effects of deregulation on a much larger scale and in more depth than has been done so far. In addition, we should put further deregulation plans on hold until we know whether or not we are headed in the right direction.

The paper begins with a background section that describes relevant aspects of the electricity system, the system's importance and the consequences of its failure, and what makes it unreliable. The next section explains why competition for unregulated profit – deregulation – doesn't work in electricity systems. This section of the paper also explains why deregulation provides motivation and opportunity for the bad behaviour and the conflicts of interest we have seen in our electricity system. Next there is an overview of the detrimental consequences of trying to deregulate electricity profits, which includes explanations of how deregulation changes people's focus, reduces resourcing, increases complexity, decreases planning and coordination, and diminishes transparency. Subsequent topics are on-the-fly implementation and conflicts of interest, followed by a section that comments on how these problems combine synergistically to increase blackout risk. Finally, conclusions and proposals are offered along with a short list of selected references.

Background

To begin, we need to describe the electricity system and understand the importance of reliable electricity in our lives and the consequences of its absence (a blackout) as well as what makes the electricity system unreliable.

The electricity system

Our electricity system is made up of people, equipment, organizations, and institutions located across the U.S. and Canada. Generating stations produce electricity, transmission systems carry it at high voltage to major users, and distribution systems then move it to smaller consumers, such as your home. Designers, operators, researchers, maintenance staff, and many others need to work effectively and in harmony to keep the lights on. Boilers, turbines, towers,

conductors, switches, breakers, transformers, and a multitude of other pieces of equipment need to operate properly to keep us warm in the winter and cool in the summer. Many organizations and institutions need to establish criteria, monitor operations, audit compliance, forecast future requirements, plan for possible problems, and perform other functions to keep prices low and prevent blackouts.

The importance of reliable electricity and the consequences of its loss

Electricity costs are much higher than the amounts people see on their bills. The amount on a bill is like the tip of an iceberg. The biggest part of electricity costs is made up of money consumers pay to help other people pay their electricity bills – the large, unseen part of the iceberg floating below the water.

For example, a consumer helps other people pay their electricity bills when s/he buys a cup of coffee, a loaf of bread, or car, or when s/he stays in a motel. All the suppliers of those goods and services need to pay their electricity bills. Unlike other products, electricity touches every sector of the economy.

Electricity increases cause cost-driven inflation that drives up interest rates. These increases force consumers to pay more for credit card purchases, bank loans, and mortgages. When Ontario opened its deregulated electricity market in 2002, the provincial electricity increase for August of that year (a hot month) added 0.2% to the Canadian Consumer Price Index for that month, raising the cost of living from Newfoundland and Labrador to British Columbia.

U.S. and Canadian tourism, business, farming, and manufacturing depend on low-cost, reliable electricity. Without it, jobs will leave our countries and our living standards will fall, with the potential for serious economic devastation. We can't afford these titanic losses.

Because electricity cost increases cause damage everywhere, most people are unaware of the extent of the damage. Many of us recognize that it is getting harder to get by, but we don't always know why. Much more of the electricity iceberg becomes visible when blackouts happen. Blackouts increase the risk of crime, put lives in jeopardy, damage public and individual health, and harm the economy.

One only needs to look at the looting, shutdown of security systems, and strain on law enforcement that has occurred during past blackouts to understand the threat to security that blackouts pose.

Lives hang in the balance during blackouts as hospitals and those at home on life support depend on the successful operation of back-up equipment. Unfortunately, back-up equipment, even when regularly tested and used properly, is not as reliable as the electricity system, which uses redundancy, extensive instrumentation, and standby equipment to keep electricity flowing. As a result, major blackouts cause deaths. In August 2003, for example, a young Ontario man who needed air conditioning because of extensive skin grafts died when the blackout plunged him into extreme heat. During the same blackout an elderly woman burned to death when she tried to use candles to see in the dark.

Public health suffers when blackouts cut off drinking water as was the case during the August 2003 blackout. People in tall buildings and major parts of big cities were without water on a very hot day. As we learned during the Chicago heat wave and blackout of July 1995, high heat without water and the cooling provided by electricity is a recipe for disaster. Blackouts can also take away needed heat during a cold winter.

In addition to leaving medical clinics without power, people trapped in subways and elevators, and emergency vehicles without gas or stuck in traffic, blackouts can be extremely costly. Medicine and food spoil, hotel room door-locks and electronic toilets become inoperable, airports close or clog, gas pumps don't work, banking machines and cell phones shut down, financial and business transactions are halted. The August 2003 blackout and its fallout cost Canada and the U.S. many billions of dollars. Estimates of the cost of California's electricity nightmare and its fallout run as high as \$60 billion U.S.

What makes the electricity system unreliable?

If a person, piece of equipment, organization, or institution does not get what it needs or otherwise fails to perform properly, the risk of blackouts increases. In 2000, when electricity traders and plant engineers in California shut down generators to create shortages of electricity and drive up electricity prices, blackouts occurred. In August 2003, when operators made errors, they contributed to turning the lights out in much of Northeastern North America.

Government and industry decision makers can make mistakes, and industry employees can fail to perform their work properly, resulting in increased blackout risk. Deregulation has caused some of these failures. It results in people losing their focus; not having the resources they need; lacking appropriate knowledge and skill; failing to plan and coordinate sufficiently; failing to perform proper maintenance,

rehabilitation and replacement; working without sufficient transparency; and experiencing conflicts of interest.

If the Shoe Doesn't Fit

The pursuit of unregulated profit works well in some industries but very poorly, if at all, in others. Trying to force unregulated profit into the electricity system will over time ruin the system and result in increased numbers of blackouts and much higher prices than are found in regulated systems. Deregulation leads to a culture of bad behavior and conflict of interest. Leading experts, theory, studies, and experience have all demonstrated this.

For example, Professor Myron Gordon, a world-recognized authority on utility rate of return, has noted that the pursuit of unregulated profit among restaurants works very well because: (1) there are many restaurants from which to choose, (2) it is easy to switch frequently among them, and (3) it is possible to curtail the luxury of dining out if industry-wide price gouging occurs. He points out, however, that this is not the case when it comes to electricity. We can see that virtually none of us have electricity choices when price gouging occurs, as it tends to in deregulated markets. Therefore, Gordon says, there is no justification for deregulation in the electric power industry except for the special interests of people who hope to profit exorbitantly at the expense of consumers (Gordon 2001).

Dr. Mark Cooper, Director of Research for the Consumers Federation of America, writes that detailed analysis shows surcharges of 25% or more in deregulated electricity markets. He demonstrates that eliminating this market manipulation and making markets competitive would drive the cost of electricity even higher in these deregulated markets than it would be in comparable situations with regulated profits (Cooper 2003, 2002).

The work of Gordon, Cooper, and others such as Senior Research Fellow Steve Thomas of the University of Greenwich, U.K. and Professor Sharon Beder have shown that the pursuit of deregulated profit harms electricity consumers (Beder 2003). This research demonstrates that both in theory and practice there is no justification for deregulated electricity.

To date there is not a single credible example of deregulation that has worked as expected nor is there one that has reduced the cost of electricity to residential customers. In March 2004, Former Canadian Deputy Prime Minister John Manley's Ontario Power Generation Review Committee stated, "We cannot rely solely on

markets to solve our problems: no jurisdiction in the world had ever done so successfully." Surveys by the South Korean Tripartite Commission (government, labor, and business), Thomas and Cooper, as well as statements by the Ontario government, support this conclusion (Thomas 2004, 2004a, 2004b; Cooper 2003, 2002).

Even hard-line competition ideologues are beginning to understand that an inelastic, volatile, transmission-constrained, peaky, unstorable, capital-intensive essential should not be subject to markets. Translated into plain language, this means: it takes significant time to build generation and run conservation programs; it costs a lot of money to borrow the money to build generation/transmission; power peaks at certain times – daily, seasonally; it's hot/cold in Toronto when it's hot/cold in New York; you can't economically store electricity or readily move it around; and an essential service like electricity shouldn't follow the financial business boom-bust cycle.

Power producers in a deregulated electricity market have much higher costs and need much bigger profits than do companies in a regulated environment. This is because deregulated risks are greater than comparable regulated risks. Greater risks mean that money lenders and shareholders expect more money (return on their investments) and they expect it faster. In addition, deregulation entails increased costs for hedging, transactions, middlemen, executive salaries, gaming, manipulation, and the like.

Deregulation pushes producers to focus more on the short term and on high returns than is necessary in a regulated environment. Higher costs and the need for greater profits have pushed deregulated power producers to cut costs drastically and to invest where high short-term returns are more likely rather than focusing on reasonable long-term returns with reasonable cost savings and reliability.

In addition, deregulated electricity markets, with their complexity, bidding, inelasticity, peakiness, and so on, afford participants many opportunities to manipulate, game, and cut corners to increase profits. Higher costs and the need for higher profits combine with the conditions in deregulated markets to provide both motive and opportunity for a culture of bad behavior. Human nature, being what it is, means there will always be some who will take advantage of others if given an opportunity. This kind of behavior increases blackout risk.

Americans and Canadians want low-cost, reliable electricity, not a blackout-prone system that unnecessarily funnels money into the pockets of big energy and finance

companies and their executives, middlemen, and the politicians in cahoots with deregulation advocates.

Unfortunately, unlike the highway system, the electricity system can fail nearly simultaneously over large parts of the U.S. and Canada. Individuals and businesses that can afford it can buy into gated electricity communities with expensive back-up power. However, the rest of us – the majority – are stuck with high prices and a greater risk of blackouts. Most hospitals, schools, small businesses, small farms, and many industries will suffer.

Consequences of Competition for Unregulated Profit

This paper presents arguments and uses examples to demonstrate that we need a major study of the impact of deregulation on electricity-system reliability. There are no sharp defining lines because the relative propensity for good and bad behavior means that better and worse behavior will be more concentrated in some cases rather than found in one place and not found in another. There are no good guys and bad guys, just motivation and opportunity for good and bad behavior. This is why Canadian and American consumers need an evaluation of all the pros and cons. They need a study that examines broadly and in depth what has happened in deregulated and regulated situations and also in situations where we can look at both the before and after. They need the independent study that their Task Force recommended.

Allowing the pursuit of unregulated profit in our electricity system causes big problems, including: changed focus, reduced resources, increased complexity, decreased planning and coordination, reduced transparency, on-the-fly implementation, and conflicting interests. These behaviors increase both the price of electricity and the risk of blackouts.

Changed Focus

The primary drivers of our electricity system used to be reliability coupled with low cost and regulated profit. During the past 15 years, unregulated profit has become the driver for large parts of the system. This change has motivated participants to focus on short-term goals and has resulted in reduced cooperation among companies.

For example, rehabilitation of Ontario's electricity system was put on hold in the rush to deregulate the system. Both the transmission system and many of the generation facilities were at or near the ends of their useful lives because of a lack of adequate

investment over the preceding 15 years. Nevertheless, consumers were forced to invest billions of dollars to introduce a deregulated system that is generally benefiting energy and finance companies rather than consumers. The money spent on introducing deregulation could have been used instead to modernize the system and reduce Ontario's blackout risk.

Deregulated company executives pay more attention to the short term and less to the long term than executives of regulated companies. A big drop in profit or share price can cost an executive in a deregulated company his or her job while an unmeasured decline in long-term reliability will go unnoticed. Many people are motivated to perform based primarily on what is measured and what is compensated for, which results in a tendency to neglect long-term goals such as reliability. Although some individuals employed by Enron are extreme examples this type of bad behavior, there are many others in dozens of other companies whose performance in this respect has been anything but stellar.

Deregulated electricity companies compete with one another for market share, investor money, and other advantages. This means that they gain and lose at one another's expense. Therefore, they are less likely to cooperate with one another than regulated companies, which do not compete with one another. When system participants take their eyes off reliability goals to chase profit, problems result because the electricity system is a large, complex entity whose components must work in harmony rather than in opposition for the system to operate reliably.

In contrast, regulated companies can make reasonable returns by doing a good job over the long term without having to sacrifice reliability for short-term profit. They are also more likely to cooperate for the common good because it is not detrimental to their self-interest.

Reduced Resources (going to the right places)

In deregulated parts of the electricity system over the past 15 years there has been a *prima facie* reduction of money, people, knowledge, training, maintenance, rehabilitation, replacement, research, etc. where these elements were (and are) most needed. Although a large independent study is necessary to detail these reductions, we can readily see some of the issues that demand investigation:

- Deregulated generation, especially the purchase of existing plants, has attracted investment that could have been used to build new generation and to improve transmission to enhance reliability.

- Deregulated companies are averse to building new generation that will drive down consumer prices and, therefore, their profits. This phenomenon has produced generation shortages in many deregulated markets and a corresponding increase in blackout risk. For example, Britain had to hastily call for more supply to keep the lights on through the winter of 2003-04 (Thomas 2003). Even with imports at maximum, Ontario has also teetered on the edge of forced cuts to keep its lights on (Brennan 2005; Brennan and Ferguson 2005; Campbell 2005; IESO 2005).
- Nearly 200,000 U.S. and Canadian electricity workers have been laid off since the advent of deregulation with most of the layoffs taking place in deregulated areas (PEST 2005; OH et al 1993-2005). For example, to get ready for playing in a deregulated market, Ontario's transmission company, Hydro One, and the province's primary generator, Ontario Power Generation, indiscriminately cut nearly one-third of their workers within a short time. These worker reductions were made even though the transmission system and eight nuclear reactors required massive rehabilitation. This foolish short-term gain cost electricity users billions of dollars in long-term costs and increased blackout risk.
- The knowledge and skill that comes from working with experienced people is at an all-time low in the electricity industry in the U.S. and Canada because of rapid layoffs of workers before the workers can transfer their knowledge and skills to others. In addition, executives and boards have been replaced with people who have little or no electricity experience. Ontario Power Generation, in addition to laying off large numbers of workers, replaced many of its executives and board members with people lacking adequate experience. This is one of the reasons why the company's nuclear rehabilitation program floundered for years with schedule delays and billions of dollars in cost overruns (Epp et al 2003; OH et al 1993-2005). These delays increased blackout risk in Ontario.
- The effect of the cuts in workers and the loss of knowledge and skill were apparent as consumers waited a week for the Ontario power system to get up and running after the August 2003 blackout. Workers struggled in particular with isolation problems affecting the Toronto subway system and equipment problems at nuclear reactors.
- Hydro One, one of the largest transmission companies in North America, currently has a board of directors on which no member has extensive

electricity transmission experience aside from the company's CEO and one union-worker representative (Hydro One 1993-2005). The company also recently terminated an agreement with its engineers and other professionals that mandated the use of mediation-arbitration and elected instead to use strike-lockout to settle disputes. This short-term thinking resulted in more than 1,000 engineers, scientists, supervisors, computer specialists and other professionals going on strike rather than accept wage and benefit reductions. This situation increased blackout risk in Ontario. On May 27, 2005, with the system being operated by management, 2,300 MW of load was dropped with cascading outages to 500- kilovolt lines. This problem was caused by operators closing in on a short circuit (Struck 2005; Daly 2005). This event had the potential to create a major blackout.

- Getting ready for and operating in a deregulated market has moved long-term goals to the back burner. Maintenance, rehabilitation, and replacement are woefully inadequate as representatives of both the Ontario government and Hydro One have admitted. The transmission system is in sad shape, and massive amounts of generation rehabilitation as well as many new plants are required within the next two decades. One only needs grade-school math to know that, on average, major transmission system components are aging at a disastrous rate. Some components have already exceeded their life expectancies. Over time, large networks require more and more maintenance, rehabilitation, and replacement. In Ontario, introducing deregulation put this work on hold, which has led to an increased risk of blackouts.
- Research and development work has decreased significantly with the introduction of deregulation and the resulting short-term focus. We can see this with a glance at successive shrinking budgets of the Electric Power Research Institute (Silverstein 2002). We see it again when observing how researchers at the former Ontario Hydro were downsized and the entire division out-sourced to save money in the deregulated market (OH et al 1993-2005). Failing to consistently explore the long term is a recipe for increasing price and blackout risk.

Increased Complexity (manipulation, gaming, and corner cutting)

In deregulated situations, electricity supply and transmission become much more complex than in regulated environments. There are more participants (generators, retailers) and more transactions (bids, contracts, pools, futures, reserves etc.) in deregulated environments. The rules for such situations need to be extensive and

they are; unfortunately, however, they are inadequate for preventing manipulation, gaming, and corner cutting.

Numerous individuals took advantage of the complexities of deregulation in California with a myriad of scams with which we are now all too familiar. There are undoubtedly many additional and as yet undiscovered loopholes and other ways to fleece consumers. In addition, the number of companies that renegotiated contracts signed when California was under duress, the number of companies that were forced to return billions of dollars, and the damning testimony and other evidence revealed by court cases and hearings clearly demonstrate that we are not talking about a few so-called bad apples here (Sinclair 2005). People working in energy corporations and financial firms and audit companies as well as traders and plant engineers failed to perform ethically. Widespread bad behavior that led to blackouts was fueled by opportunity and motivation.

The California experience is not unique. Studies compiled by Cooper show that one deregulated market after another has seen excess surcharges of 20% to 400% instead the lowered prices that competition is supposed to produce (Cooper 2003, 2002). This is because most markets are composed of a handful of major generators along with some minor ones. Generators bid supply every 30 to 60 minutes with the knowledge of demand to within 1 or 2%. They know the supply available to each major bidder. They understand the transmission constraints and often have good information on required maintenance outages. Imagine being able to play the stock market with this kind of information. The situation is like that of card players who have full knowledge of the cards each player holds and the order in which each player will likely play them. They are playing against the house and know in advance how the house will bid every hand. These players interact together 24/7 for years. They don't need to talk to one another to consistently win big as consumers lose. They only need to continue to play in this one-sided game.

If this setup isn't bad enough, each player also has a so-called ace in the hole: the ability to take generation out of service at just the right time to drive supply lower, an action that radically increases profits because of higher purchase prices and reduced producer fuel costs. Unfortunately, it also increases blackout risk. In California in the year 2000, so many people were playing their aces that rolling blackouts were needed on a Sunday, a day with very low demand.

Several utilities (San Diego Gas & Electric Co., Pacific Gas & Electric Co., Southern California Edison) have requested that forecast demand not be disclosed to prevent market manipulation. Recently Edison launched a court case to prevent disclosure of

projections of peak usage (AP 2005). This is another futile attempt to fix a broken game.

Many markets have also experienced increased blackout risk as participants failed to build new generation in time to keep demand from threatening to exceed supply. When the capacity to accommodate planned and forced outages, extreme weather, and other contingencies isn't available, blackouts can occur. California, New York, Britain, Ontario and others have struggled with this problem. Both New York (summer 2001) and Ontario (summer 2003) have had to quickly install temporary generators to manage blackout risk.

Decreased Planning and Coordination

Deregulated systems are far more complex than regulated systems because of increased numbers of participants, transactions, and relationships. This increase requires a greater amount of planning and coordination to achieve the harmonious behavior needed for the same level of reliability provided by an equivalent regulated system.

Instead, there has been a decrease in planning and coordination. Market forces are relied on to achieve harmony (that is, to produce the equivalent of very sophisticated design). However, the market's trial-and-error method can lead to numerous mistakes that reduce reliability. Most deregulated markets, for example those in Britain, Ontario, New York, and California, have suffered through the failure of market forces to provide adequate power supply.

The Ontario government is currently scrambling to add a small, but still insufficient, amount of planning to its deregulated system with the establishment of the Ontario Power Authority (OPA). One of OPA's main functions is to transfer risk from power producers to consumers by writing supply contracts with producers when the market doesn't entice them to build sufficient generation. OPA is designed to provide the supply necessary to maintain adequate reliability by guaranteeing what the market won't guarantee.

Reduced Transparency

Motivation and opportunity contribute to bad behavior; reducing the chances of getting caught makes the situation much worse.

Regulated electricity companies are compensated for their investment and performance by regulators using rate hearings with interveners. Their costs are examined, and their programs are explored and questioned. Regulated companies are much less likely to take big, inappropriate risks because they are striving to make reasonable returns rather than rolling the dice for big profits. In addition, they need to justify costs and demonstrate their concern for reliability.

Unfortunately, deregulated companies do not have to justify prices or explain costs to the public. This allows some individuals to take inappropriate risks and/or ignore reliability for personal gain. They can bet to win big and escape with the cash. Mergers and acquisitions, asset sales, bankruptcies, movement of executives among companies, and other similar phenomena increase the chances that the problems created by particular individuals will have to be handled by others. At the end of the day, consumers are on the hook for this bad behavior because, over time, neglecting reliability increases prices and blackout risk.

We cannot afford to ignore what companies are doing or not doing to sustain long-term reliability. Electricity is an essential for many and at times for all of us. Without an affordable, reliable supply of electricity, lives will be shortened or lost and hardship will be extreme. We cannot afford to let those in the electricity business operate behind closed doors.

There is ample evidence both in the U.S. and Canada that deregulation has resulted in millions of dollars of electricity-industry assets being spent on lobbying politicians, financing campaigns, excessively compensating executives (CRP up to 2005; EO 2003). The majority of the public understands that this money isn't being used on their behalf. And, although these costs are included in the price of electricity, they certainly are not funding reliability.

For example, prior to the opening of the Ontario deregulated electricity market, Canadian conglomerate Brascan Corporation donated \$150,000 to the campaign of the soon-to-be-elected leader of the then-governing Tory party. Brascan was then allowed by the government to buy four no-risk hydroelectricity stations. This new owner of four Mississauga generators made its money back and more when deregulation began in Ontario. Brascan drained Rocky Island Lake for profit, at the expense of local tourism jobs and fish habitat (CP 2005; McKay 2005). During a half century of regulated operation, Ontario Hydro never dropped the water level as far as Brascan did in the deregulated market during the summer of 2002.

The Mississauga dams were designed to operate at times of peak demand and then to be shut down while water levels replenished. Maintaining an adequate supply of water behind these dams helps prevent blackouts. Excessive operation of the dams made money for Brascan but reduced a lake to sand flats and exposed tree stumps and decreased electricity reliability.

Much of Brascan's inappropriate behaviour would most likely not have occurred in the more transparent operation of a regulated industry.

On-the-Fly Implementation

Using complex systems in new situations without appropriate testing, pilot projects, risk management, gradual implementation, and back-up procedures is an unsound practice.

There is no one standard for a deregulated system. Everywhere that deregulation has been introduced, it is unique. In addition, all deregulated systems have been radically changed over time. Britain is a prime example. After more than 15 years, the British are still making radical system changes to their deregulated power industry in response to big problems that keep arising. Thomas details the history of this ongoing fiasco in his paper "The British Model in Britain: Failing Slowly." If Britain, an electricity island, can't get the broad strokes of deregulation right after all this time, then we are not talking about a working deregulated system but rather a very large pilot project, one that has unnecessarily cost consumers billions of dollars without providing a reliable, reasonably priced electricity supply. Research by Thomas and Cooper shows ongoing market manipulation by companies in Britain, resulting in higher prices to consumers.

Imposing a massive pilot project on a system that literally and figuratively supplies the life support for individuals and the larger society is not something we should be proud of. Electricity is an essential service, and we shouldn't be experimenting with it on this scale if we have not yet seen a working example of the system. As noted previously by Manley's Committee, "to date there is not a single credible example of deregulation that has worked."

Ontario scheduled and then postponed opening its deregulated electricity system twice and then finally opened it only to cap rates six months later in response to a large-scale public outcry. Like Britain's electricity system, Ontario's deregulated so-called system has been radically altered several times, which indicates that the province is running a pilot project with people's lives and the Ontario economy as guinea pigs. This experiment has pushed the province below adequate reserve

capacity requirements on more than one occasion. The resulting increased blackout risks are a by-product of deregulation. (The July 2005 - December 2006 "Ontario Independent Electricity System Operator Outlook" forecast states that reserve capacity requirements are not met for 10 weeks of the summer of 2005.)

You would not think it a good idea to unnecessarily increase the risk of losing power when a member of your family is on the operating table. Perhaps, we shouldn't take this with other people's family members. If NASA needs to be more cautious than it has been in the past to protect the lives of a small number of astronauts, how much more caution should we exercise for a system that protects many lives and most of our livelihoods?

Our electricity system was built over many decades with extensive planning and testing and gradual implementation. This allowed planners, engineers, operators, maintainers, foresters, and others to correct problems in a timely manner. Then, deregulation was quickly introduced and the electricity system was allowed to operate as market. This change increased the risk of system failure. Lines now regularly carry heavy loads as the result of market forces rather than just on very hot or very cold days.

When you quickly take parts of a complex system up to near capacity in new situations, you can expect problems just as you would if you quickly ran a new generating station up to full load without the procedure of gradual increases that we currently use. The situation can be even worse for old lines that are suddenly loaded to near their design capacity. Gradual loading lets us detect and correct conditions such as overheating clamps before these conditions cause big problems.

Our electricity system, unlike the highway or gas systems, can fail nearly simultaneously over large parts of the U.S. and Canada. We need to exercise more caution with electricity than we do with other systems because of the extent and consequences of such failures.

Our electricity system is in poor shape, as many observers have noted. To provide the maintenance, rehabilitation, replacements, and new lines that are needed will take decades and tens of billions of dollars. This work must be done if we want a reliable system. To turn the system into a deregulated market, an undesigned-for-use, will cost consumers many tens of billions of dollars more than the necessary system rehabilitation would, and this money will not directly reduce the risk of blackouts but will only enrich energy and finance firms.

Conflicting Interests

Individual electricity suppliers can, as previously noted, dramatically increase their profits by reducing supply. Although motivation, opportunity, and a lack of transparency can lead suppliers to maliciously manipulate the system, there are also cases in which a supplier's justifiable self-interest can lead to problems. This happens when there is a direct conflict between the common good and a supplier's desire to both protect an investment and increase profit.

For example, there are usually many reasons for either taking a generator out of service or leaving it in service. Repairing damaged equipment as quickly as possible prolongs its life and protects the equipment owner's investment. However, when equipment is repaired during periods of peak load, not only is the investment protected but profit for opejimmysexton@z-linedesigns.com rating generators is also driven up. In a deregulated system, a supplier may err on the side of self interest and shareholder profit. In a regulated system the primary supplier often errs on the side of overall electricity reliability if the risk of equipment damage is not too great. The regulated supplier, in order to make a reasonable profit, needs to demonstrate good performance. The deregulated supplier, in order to make a much larger and competitive profit, needs to protect its investment and seize any profit-making opportunities as they arise.

The owner of several restaurants who closes one during peak sales times usually reduces profits and damages customer loyalty. However, the owner of several generation facilities who shuts down one generator at peak sales times can dramatically increase profits without the down side of damaging customer loyalty because that owner is selling to a market rather than to a specific customer.

Because of conflicting interests, there is, overall, an increased probability of less generation capacity being available during peak times in a deregulated market than in a regulated one. The behaviour of California's deregulated market in 2000 was an example of this phenomenon.

Electricity deregulation, because of its nature, often puts suppliers' interests in conflict with the common good of reasonable prices and reliability. This conflict increases blackout risk.

Sinister Synergies

This paper highlights some of the effects of deregulation on electricity-system reliability and demonstrates that there are situations in which the pursuit of unregulated profit can increase blackout risk. As we know, some of these effects have already caused blackouts.

These effects combine to produce sinister synergies – an overall blackout risk that is greater than the sum of the risks produced by each component.

When you don't know what you're doing and don't have enough resources to do the job, things can go from bad to worse. If you're also being pushed to quickly grab big profits, then there is a significant possibility that big problems will occur. On top of this, if we add reduced cooperation, increased complexity, a deregulated system in a pilot stage, an electricity system undergoing rapid and novel loadings, and conflicts of interest, then we have the makings of unacceptable blackout risk.

The sinister synergies caused by inadequate maintenance, rehabilitation, and replacement of system components are easy to see if our asset is a fleet of taxis. If some taxis fail because they have not been adequately maintained, there is a ripple effect of greater demand on and, therefore, shortage of coverage by the other taxis in the fleet. Some passengers may not get service. Such inadequacies will cause synergistic blackout risk in the electricity system. However, all the taxis in a fleet rarely if ever fail simultaneously. Unfortunately, large parts of the electricity system can and do.

Conclusions and Proposals

Our electricity system, whose personnel and equipment extend across Canada and the U.S., becomes unreliable when parts of it do not perform properly. The system is a matter of life and death for people and the economy and thus must be treated with prudence, especially because it can fail nearly simultaneously over large parts of the continent.

Deregulation has not worked in the electricity system as researchers have documented. Deregulation has higher costs and participants need to generate more profit than is the case in a regulated electricity industry. The higher costs and profits demanded in a deregulated system push participants to make disastrous cuts and focus on high, short-term returns rather than on reliability with justified costs and regulated, reasonable returns.

It is easy to understand why a deregulated environment tempts people to grab big returns quickly. However, this behaviour results in insufficient resources being directed to the right places. This situation is made worse because many decision makers and workers don't have the knowledge and experience to understand what is required to maintain reliability.

Deregulation pushes people to quickly and consistently generate large profits and provides opportunities for manipulation, gaming, and corner cutting. In addition, reduced transparency in a deregulated market leads some to believe they can get away with these activities. Their bad behavior reduces reliability.

Moreover, a short-term outlook doesn't provide the people, money, knowledge, skill, training, maintenance, rehabilitation, replacement, and research that are needed for a blackout-resistant electricity system. The rush to make big money has also led to on-the-fly implementation of deregulated systems that then need to be altered continuously and radically.

Deregulation puts the interests of many participants in electricity system in conflict with the pricing and reliability interests of consumers.

Unlike other systems, the electricity system needs to work harmoniously to prevent blackouts: if parts of the system don't work properly, then cascading failures can occur.

We need to recognize how important the electricity system is, what the consequences of failure are, and what is needed to keep it reliable, that is, blackout-resistant. Like NASA, we need to put a hold on launches that can't be carried out safely because, like an unsafe NASA launch, a blackout puts lives at risk. It also causes immense economic damage. Experimenting with this massive, complex, essential system based on faith in market forces is not justifiable, given the consequences of failure. The stakes are simply too high.

Therefore, I recommend that we put any further deregulation initiatives on hold until we have a better and more detailed understanding of how deregulation is truly affecting our electricity system. Only then can we make reasonable decisions about the direction in which we should be moving.

This paper is not a comprehensive look at deregulation's detrimental effects on electricity system reliability. It is an overview that points out that there are detrimental effects and that they can cause and have caused disastrous blackouts.

I recommend that, to understand the effects of deregulation, we proceed with a thorough and independent investigation, as recommended in the Task Force's final report. Only through a broad and in-depth look at deregulation and how it affects our electricity system can we understand and address this important issue.

This study should examine what has happened in deregulated and regulated situations and also in situations where we can look at electricity systems both before and after deregulation.

We need to understand the effects that deregulation has had on overall prices; worker numbers, qualifications, and education; worker knowledge, skill, and training; research and development; planning and coordination; manipulation, gaming, and corner cutting; investment in maintenance, rehabilitation, and replacement; executive and board member qualifications and experience; incidents and accidents; and many other areas.

I know that many people in government and the electricity industry have an ideological belief in electricity deregulation. I also understand that many people, including people presenting papers in these workshops, receive compensation that depends directly on deregulation. However, I also believe that all of us have a duty to consumers in Canada and the U.S. to put ideology and personal gain aside and to be duly diligent in such an important matter.

Deregulation may work well in some areas, but it works poorly, if at all, in the electricity system. We need to stop making inadequate analogies to the gas and the telecommunication systems and start looking at the electricity system itself. We need to stop operating with blind faith and get the facts so that we can base our decisions on knowledge.

As John Maynard Keynes was reported to have said: "When I get new information I change my mind, what do you do?" Now is the time for us to begin to get new information on deregulation as the Task Force Report has recommended. Now is the time to take a thorough look at what the pursuit of unregulated profit is doing to our electricity system and then decide if we should change our minds. Not investigating such a critical issue is not an option that is open to us.

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Public Workshops and Public Comment

The final element of DOE and NRCan effort to fulfill the Task Force's Recommendation to conduct an independent study of the relationships among industry restructuring, competition in power markets, and grid reliability, and how those relationships should be managed to best serve the public interest was to provide opportunities for public comment and discussion of the issue papers. This was accomplished by conducting two public workshops at which the issues papers were presented and discussed, and by creating two websites through which public comment was received directly on the issue papers and workshops.

Two public workshops were held in the fall of 2005. The first was held in Washington, DC on September 15, and the second was held in Toronto, Ontario on September 28. Both workshops were organized as panel discussions in which groups of 3 or 4 authors presented their papers in the form of responses to selected questions derived from themes raised by their papers. Public comment was taken following each panel session. Appendices B and C contain the agenda and list of participants for Washington DC and Toronto, Ontario public workshops, respectively.

The public workshops and public comment process were supported by electronic websites maintained by DOE and NRCan.¹ The websites allowed for: 1) downloads of the issue papers; 2) registration for the public workshops; 3) downloads of the agendas for and transcripts of the two workshops; and 4) posting and viewing of public comments received on both the issue papers and the workshops. Appendix D contains the public comments received through the websites.

Public Workshop in Washington DC on September 15, 2005

The first public workshop was held in Washington, DC on September 15, 2005. The workshop was opened by Clay Sell, Deputy Secretary, U.S. Department of Energy. The workshop was facilitated by Jimmy Glotfelty of ICF Consulting. Seventy one individuals participated in the workshop.²

The first panel, Blackout Causes and Role of Reliability Rules, featured: David Nevius, NERC; Kellan Flukiger, Alberta Department of Energy; and Jack Casazza, Power Engineers in Supporting Truth. The panel addressed two sets of questions: 1) The identified causes of many major blackouts (e.g. 1965, 1977, 1996)

¹ DOE website: <http://www.energetics.com/reliability.html>
NRCan website: <http://www2.nrcan.gc.ca/es/erb/erb/english/conference.asp>

² Transcript can be downloaded from:
DOE website: <http://www.energetics.com/reliability.html>

also contributed to the August 14, 2003 blackout. Has restructuring made them worse? 2) Will the U.S. Energy Legislation that was signed into law on August 8, 2005 – specifically, the call for mandatory reliability standards - prevent future blackouts? Are additional changes also needed? What are they?

The second panel, Addressing Changing Industry Structure and the Need for Transmission Investment, featured David Goulding, IESO; Jose Delgado, ATC Scott Thon, Altalink; and John Hughes, ELCON. The panel addressed two sets of questions: 1) What impacts – both positive and negative - has restructuring had on reliability? What are the best ways to mitigate negative impacts and enhance positive ones? 2) Is “extra” investment in transmission appropriate in view of its contribution to the public interest in reliability? And, if so, how much extra?

The third panel, The Appropriate Role of Markets and Technology in Safeguarding the Public Interest in Reliability, featured Andrew Ott, PJM; John Wilson, Ontario Energy Coalition; and Robert Thomas, Cornell University. The panel addressed two sets of questions: 1) Are market-based principles for organizing wholesale electricity trade limited in accommodating the public interest in electricity reliability? If so, how are they limited, and what should be done to address these limits? 2) What are your perspectives on the roles and limits of new technologies to address potential problems emerging from the aging workforce of the industry and the reductions in manpower at utilities?

Public Workshop in Toronto, Ontario on September 28, 2005

The second public workshop was held in Toronto, Ontario on September 28, 2005. The workshop was opened by Tom Wallace, Natural Resources Canada. The workshop was facilitated by Bryne Purchase of Queen’s University. Fifty five individuals participated in the workshop. Some of the panel questions were modified for the workshop in Toronto to reflect the discussions that had taken place at the workshop in Washington.³

The first panel, Blackout Causes and Role of Reliability Rules, featured: David Goulding, Independent Electricity System Operator (IESO); John Hughes, ELCON; and David Nevius, North American Electric Reliability Council (NERC). The panel addressed two sets of questions: 1) The identified causes of many major past blackouts (e.g., 1965, 1977, 1996) also contributed to the August 14, 2003 blackout. How has restructuring affected these causal factors? Has it made them worse; if so, how? 2) Will the U.S. Energy Legislation that was signed into law on August 8, 2005

³ Transcript can be downloaded from:

NRCAN website: <http://www2.nrcan.gc.ca/es/erb/erb/english/conference.asp>

- specifically, the call for mandatory reliability standards - prevent future blackouts? Are additional changes also needed? What are they?

The second panel, Addressing Changing Industry Structure and the Need for Transmission Investment featured: Scott Thon, AltaLink Management Ltd.; Tom Welch, PJM Interconnection; and John Wilson, Ontario Electricity Coalition. The panel addressed two sets of questions: 1) What impacts - both positive and negative - has electricity industry restructuring had on reliability? What are the best ways to mitigate restructuring's negative impacts and enhance its positive impacts? 2) Is greater emphasis on transmission construction appropriate in view of its contribution to the public interest in reliability? And, if so, how much extra emphasis is warranted and through what means.

The third panel, The Appropriate Role of Markets and Technology in Safeguarding the Public Interest in Reliability, featured: Kellan Fluckiger, Alberta Department of Energy; Jack Casazza, Power Engineers Supporting Truth; and Robert Thomas, Cornell University. The panel addressed two sets of questions: 1) Are market-based principles for organizing wholesale electricity trade limited in their ability to accommodate the public interest in electricity reliability? If so, what are the limits of these principles and what should be done to address these limits? 2) What are your perspectives on the roles and limits of new technologies to address potential problems emerging from the aging workforce of the electricity industry and the reductions in manpower at utilities?

Additional Public Comment Received Through the Website

Opportunities for public comment and discussion of the issue papers were provided both through two public workshops at which the issues papers were presented and discussed and through public comment received directly on the issue papers and workshops.

Direct posting of public comment on the issue papers and workshops was provided for on both the DOE and NRCAN websites created for the project. The public comment period was open from the time the issues papers were first posted and the workshops were announced until approximately one month following the second public workshop in Toronto. During this period, three comments were received. Appendix D contains the text of these comments.

Appendix A - Short Biographies of Issue Paper Authors

John A. Casazza

Power Engineers Supporting Truth (PEST)

John A. (Jack) Casazza is currently President of the American Education Institute, a not-for-profit organization that he founded in 1994 dedicated to providing the education needed in setting electric power policy. He is a past Director for the Georgia Systems Operation Company, and has been a member of the Executive Committee of the New York State Electric Reliability Council and the Energy Engineering Board of the National Research Council. He is a past President of CSA Energy Consultants and Vice President for Planning and Research for the Public Service E & G Co. He was involved for many years in the development of transmission and generation in PJM and participated in the founding of NERC. Recently he helped form Power Engineers Supporting Truth (PEST) dedicated to improving the technical competence of government and industry officials and the leadership role of engineers. Jack is an IEEE Life Fellow and has received many awards for his contributions to the development of electric power systems. He is the author of more than 80 publications.

Frank Delea

Power Engineers Supporting Truth (PEST)

Frank Delea is associated with the American Education Institute (AEI) and with Power Engineers Supporting Truth (PEST). Under AEI's auspices he has taught courses on power system engineering and on FERC's orders and regulations dealing with deregulation / restructuring. Under PEST's auspices he has co-authored a number of papers dealing with the 2003 blackout, reliability and the restructuring of the electric power industry. He has co-authored a text entitled "Understanding Electric Power Systems – An Overview of the Technology and the Marketplace" published by Wiley Interscience and a paper entitled "Why Have Lessons Learned Not Been Transferred to the Current Generation of Power System Engineers, Managers and Policy Makers and What Can Be Done About It?" that was presented in the June general meeting of the Power Engineering Society of the IEEE. He worked for Con Edison for over 30 years with senior level managerial experience in bulk power system planning, forecasting, corporate capital budgeting, rate cases, corporate planning and corporate restructuring.

José M. Delgado
President and Chief Executive Officer
American Transmission Co.

José Delgado is President and Chief Executive Officer of American Transmission Co., the first multi-state, transmission-only electric utility in the United States. Formed in 2001, ATC serves portions of Wisconsin, Michigan and Illinois. Previous to the formation of ATC, Delgado spent 27 years at Wisconsin Electric Power Co. He currently serves on the Edison Electric Institute board of directors and is vice chairman of the Policy Committee on Energy Delivery. He also serves on the board of directors of the Association of Edison Illuminating Companies and on the advisory board of the Consortium for Electrical Reliability Technology Solutions. He previously has served in advisory roles for the Mid-America Interconnected Network, Midwest Independent Transmission System Operator, North American Electric Reliability Council, Electric Power Research Institute and the Department of Energy. Delgado has bachelor and master's degrees in electrical engineering from Marquette University and a master's in business administration from the University of Wisconsin-Milwaukee.

Kellan Fluckiger
Executive Director, Electricity Division
Alberta Department of Energy

Kellan Fluckiger is the Executive Director of the Electricity Division with the Alberta Department of Energy. Kellan joined the department in July 2003. He brings 27 years of experience at all levels in the electric power industry to this position. His major responsibility is policy development related to Alberta's electricity sector.

During the last 27 years, Kellan has become a leading expert in all phases of electricity restructuring and the synthesis of technical, practical and political perspectives. Kellan has worked at Pacific Gas and Electric Co., Arizona Public Service, Idaho Power Co., the California ISO, the office of the Governor of California and the California Consumer Power and Conservation Financing Authority. He has managed electricity markets, system planning, operations and engineering and has been active in all phases of restructuring in multiple jurisdictions.

Kellan's has served in various capacities on industry boards and councils. These include: the Western Electricity Coordinating Council Operating Committee, Reliability Committee and Board of Directors, the Northwest Power Pool Operating Committee and Board of Directors, the North American Electric Reliability Council Operating Committee and Security Committee and the Committee for Regional

Electric Power Coordination. In addition, Kellan has testified before the US House of Representatives, the Federal Energy Regulatory Commission and both houses of the California Legislature. He has been a sought after speaker both nationally and internationally on the subject of electricity restructuring.

Kellan graduated from Ottawa University with a B.A. in Business Administration and Management. He also attended Brigham Young University, San Francisco State University and the University of Idaho. Personal interests include music, martial arts, skiing and a large family consisting his wife and 10 children.

Dave Goulding, B. Tech., P.Eng
President & CEO

Independent Electricity System Operator

Mr. Goulding was appointed President and Chief Executive Officer of the Independent Electricity System Operator in March 1999.

Under Mr. Goulding, Ontario's IESO is responsible for overseeing the safe and reliable operation of Ontario's bulk electrical system - one of the most diversified, reliable and efficient in the world. The organization also oversees the IESO-administered wholesale electricity markets.

Mr. Goulding is a member of the Stakeholder Committee of the North American Electric Reliability Council (NERC) as well as The Consortium for Electric Reliability Technology Solutions (CERTS) Advisory Board. He was also a member of the Ontario government's Electricity Conservation And Supply Task Force and a former member of the Executive Committee of the Northeast Power Co-ordinating Council and Board of Trustees for NERC.

Prior to his appointment to Ontario's IESO, Mr. Goulding was Senior Vice-President of Central Market Operations with Ontario Hydro.

Born in Yorkshire, United Kingdom, Mr. Goulding was educated at the University of Bradford, England, where he obtained a Bachelor of Technology Degree.

Phillip G. Harris
President and CEO
PJM Interconnection LLC

Phillip G. Harris, a 30-year energy industry veteran, is president and chief executive officer of PJM Interconnection. PJM, the nation's first fully functioning regional transmission organization, administers the world's largest energy market and operates the nation's largest electricity grid. Mr. Harris is also chairman of the PJM Board.

Mr. Harris has served as a member of the North American Electric Reliability Council's (NERC) Board of Trustees. He serves on the board of the Mid-Atlantic Area Council (MAAC), one of 10 reliability councils within NERC, and has served as the regional manager of MAAC. He also is a member of the National Association of Corporate Directors, serving on its Corporate Advisory Committee.

Mr. Harris frequently provides expert testimony on electric-industry restructuring issues before federal and state regulatory agencies, as well as Congress and state legislatures. He has written articles about the competitive electricity marketplace for various publications and is a national subject matter expert who is frequently quoted by media outlets, including The Wall Street Journal, CNN, C-SPAN, Forbes, Fortune and Time. He has been a featured speaker in the National Press Club's Newsmaker Series.

Mr. Harris has forged partnerships with Electricité de France and Tokyo Electric Power Co. (operators of the world's largest and second-largest power grids, respectively) to further each company's preparedness to meet the world's rapidly increasing demands for reliable and affordable power.

Under Mr. Harris' leadership, PJM has twice been named to the National Companies that Care Honor Roll for its commitment to its employees and the community. PJM also was selected as one of the 100 Best Places to Work in Pennsylvania for 2004. In addition, the company was recognized by the United States Energy Association with a Volunteer Organization of the Year Award for its support of USEA's international assistance work.

A native of New Mexico, Mr. Harris is a graduate of the United States Military Academy at West Point, with a degree in Applied Science and Engineering. He earned his Master of Arts in Business Management, with an emphasis on research and statistical methodology, from the University of Northern Colorado. He is a Certified Management Accountant and a Computer Systems Professional.

PJM Interconnection ensures the reliability of the high-voltage electric power system serving 51 million people in all or parts of Delaware, Indiana, Illinois, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia the District of Columbia. PJM coordinates and directs the operation of the region's transmission grid; administers a competitive wholesale electricity market, the world's largest; and plans regional transmission expansion improvements to maintain grid reliability and relieve congestion. Visit PJM at www.pjm.com.

John P. Hughes
Vice-President - Technical Affairs
Electricity Consumers Resource Council

ELCON is a national trade association representing large industrial consumers of electricity. ELCON's member companies own and operate manufacturing facilities throughout the United States and in many foreign countries. They produce a wide range of products including: chemicals, petroleum, paper and forest products, motor vehicles and automotive parts, industrial gases, machinery, computer chips, food and agricultural products, and consumer goods. Many ELCON members generate or cogenerate some of their electricity requirements.

Since joining ELCON in 1987, Mr. Hughes has provided technical and analytical support for ELCON's interventions at FERC, DOE, EPA, and state PUCs, and in testimony before Congress, and is the author of many ELCON position papers and regulatory filings. He represents Large End-Use Consumers on the Executive Committee of the North American Energy Standards Board (NAESB). He also is active with the North American Electric Reliability Council (NERC). From January 2002 to December 2003, Mr. Hughes chaired the SeTrans RTO Stakeholder Advisory Committee (SAC).

Prior to joining ELCON, Mr. Hughes was Director of Economic Research at the Niagara Mohawk Power Corporation. He was previously Chief Economist of the Massachusetts Energy Facilities Siting Council. Mr. Hughes is both an engineer and economist by training.

George C. Loehr**Power Engineers Supporting Truth (PEST)**

George C. Loehr is a nationally recognized expert on bulk power system reliability. He is the former Executive Director of the Northeast Power Coordinating Council, and now does management consulting, appears as an expert witness, speaks, writes, and teaches a variety of courses on power systems for non-technical professionals. Loehr has published extensively in trade and other magazines, and has testified before various state legislative bodies on reliability and blackouts. He serves as Vice President and member of the Board of Directors of the American Education Institute (AEI), as is a founding member of Power Engineers Supporting Truth (PEST). Mr. Loehr also serves as an unaffiliated member of the Executive Committee of the New York State Reliability Council, and chairs its Reliability Compliance Monitoring Subcommittee.

David Nevius**Senior Vice President****North American Electric Reliability Council (NERC)**

Mr. Nevius is Senior Vice President of the North American Electric Reliability Council (NERC), located in Princeton, New Jersey. NERC's mission is to ensure that the bulk electric system in North America is reliable, adequate and secure. Since joining NERC in 1977, Mr. Nevius has been involved in all aspects of NERC's reliability activities. Mr. Nevius leads NERC's efforts to transform NERC from a voluntary, peer review organization, into an industry self-regulatory organization that sets and enforces compliance with reliability standards for the bulk power system, including the development of pending reliability legislation. He also oversees NERC's efforts to ensure that the electric industry's critical infrastructure assets are protected from physical or cyber threats. Mr. Nevius began his engineering career at Public Service Electric and Gas Company (NJ) in their electric system planning department, where he was responsible for transmission expansion planning. He holds a bachelors degree in Electrical Engineering (1969) and a masters degree in Engineering Management (1975) from Drexel University, and is a registered Professional Engineer in the state of New Jersey.

Andrew L. Ott
Vice President, Market Services
PJM Interconnection

Mr. Ott is responsible for the oversight of PJM's Market Development, Market Operations and Market Strategy, with a concentration on Locational Marginal Pricing, Financial Transmission Rights, and the Day-Ahead Energy Market.

Mr. Ott has extensive experience in energy market restructuring, including design and implementation issues, and in power-system engineering applications.

Prior to joining PJM, Mr. Ott was employed by GPU for 13 years in transmission planning and operations.

Mr. Ott received a Bachelor of Science in Electrical Engineering from Pennsylvania State University. He also received a Master of Science in Applied Statistics from Villanova University.

PJM Interconnection ensures the reliability of the high-voltage electric power system serving 51 million people in all or parts of Delaware, Indiana, Illinois, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. PJM coordinates and directs the operation of the region's transmission grid; administers a competitive wholesale electricity market, the world's largest; and plans regional transmission expansion improvements to maintain grid reliability and relieve congestion. Visit PJM at www.pjm.com.

Robert J. Thomas
Professor, Electrical and Computer Engineering
Cornell University

Robert J. Thomas currently holds the position of Professor of Electrical and Computer Engineering at Cornell University. During the 1979-1980 academic year he spent his sabbatical leave with the U.S. Department of Energy Office of Electric Energy Systems (EES) in Washington, D.C. In 1987 and 1988 he was on assignment from Cornell University to the National Science Foundation as the first Program Director for the Power Systems Program in the Engineering Directorate's Division of Electrical Systems Engineering (ESE). He is the author of over 100 technical papers, and two book chapters. He has been a member of the IEEE United States Activity Board's Energy Policy Committee since 1991 and was the committee's Chair from 1997-1998. He was a member of the IEEE Technology Policy Council, has served as

the IEEE-USA Vice President for Technology Policy, and has been a member of several university, government and industry advisory Boards or Panels. His current technical research interests are broadly in the areas of analysis and control of nonlinear continuous and discrete time systems with applications to large-scale electric power systems. He is the founding Director of the 11 university member National Science Foundation Industry/University Cooperative Research Center, PSerc (Power Systems Engineering Research Center), a Center focused on problems of restructuring of the electric power industry. He was a member of the USDOE Secretary's Power Outage Study Team (POST) and is a founding member of the Coalition for Electric Reliability Solutions (CERTS) Management Steering Committee (MSC). He was on assignment to the USDOE in 2003 as a Senior Advisor to the Director of the Office of Electric Transmission and Distribution and a member of the DOE August 14, 2003 blackout investigation team. He is a member of Tau Beta Pi, Eta Kappa Nu, Sigma Xi, ASEE and a Fellow of the IEEE.

Scott Thon
President & Chief Executive Officer
AltaLink Management Ltd.

Mr. Thon's broad business background in the power industry includes specific expertise in the transmission and distribution sectors, wholesale energy trading, independent power projects and energy risk management. Mr. Thon is the Chair of the Canadian Electricity Association's Transmission Council and a registered Professional Engineer. He serves on the Board of Directors of The Canadian Electrical Association, The Calgary and Area United Way, The Calgary Children's Initiative as well as on the Board of Governors for Bow Valley College. Mr. Thon earned his Bachelor of Science degree in Electrical Engineering from the University of Saskatchewan and he has completed the Richard Ivey Executive Program at the University of Western Ontario.

Ellen Vancko
Director of Communications and Government Affairs
North American Electric Reliability Council (NERC)

Ms. Vancko is the Director of Communications and Government Affairs for the North American Electric Reliability Council (NERC). Since joining NERC in 2000, she has been responsible for media relations, message development, public policy, and external affairs. Before coming to NERC, Ms. Vancko was Director of Policy Analysis at Allegheny Energy, Inc., where she was responsible for analyzing emerging industry trends and developing and implementing corporate policy on

issues affecting the company's regulated and unregulated subsidiaries at the state and federal levels. Prior to that, Ms. Vancko was Manager of Power Supply Regulation at the Edison Electric Institute, where she managed a broad range of issues associated with state and federal electricity restructuring initiatives. She also served as an energy analyst and management consultant to numerous government, industry and institutional clients and has more than 24 years of diverse energy experience. Ms. Vancko has an M.S. in Energy Management and Policy from the University of Pennsylvania, a B.A. in Political Science from George Washington University, and completed the Harvard Law School Program on Negotiation for Senior Executives.

Thomas L. Welch
Vice President, External Affairs
PJM Interconnection

Thomas L. Welch, vice president of External Affairs for PJM Interconnection, is responsible for federal and state regulatory relations, federal government policy and corporate communications at the regional transmission organization, which serves 13 states and the District of Columbia.

Mr. Welch joined PJM in April 2005 as general manager of Market Strategy. Prior to joining PJM, Mr. Welch served for 12 years as the chairman of the Maine Public Utilities Commission. During his terms on the PUC, Maine's electricity industry was restructured, bringing the benefits of competition to consumers. He also has served as the chief deputy attorney general at the Pennsylvania Office of Attorney General and as an attorney at Bell Atlantic and the San Francisco law firm McCutchen, Doyle, Brown & Enersen. Mr. Welch also was an assistant professor of law at Villanova University School of Law.

Mr. Welch has participated in many professional organizations in support of the industry. He served for 12 years on the National Association of Regulatory Utility Commissioners and was a member and state chairman of the Federal-State Joint Board on Jurisdictional Separations. He also participated in GrowSmart Maine, a statewide organization focused on stopping sprawl in that state.

PJM Interconnection ensures the reliability of the high-voltage electric power system serving 51 million people in all or parts of Delaware, Indiana, Illinois, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. PJM coordinates and directs the operation of the region's transmission grid; administers a competitive wholesale electricity market, the world's largest; and plans regional transmission expansion

improvements to maintain grid reliability and relieve congestion. Visit PJM at www.pjm.com.

John F. Wilson

Energy Consultant

Ontario Electricity Coalition member, registered professional engineer

John Wilson worked in the electricity industry in the Ontario and the U.S. for both public and private utilities. He worked in design, research and projects with experience in generation, transmission, and manufacturing. He served as President of the Society of Energy Professionals representing engineers, scientists and other electricity professionals. He negotiated with Ontario Hydro and the Ontario government over the breakup of Ontario's primary electricity company and the introduction of deregulation. He served on the board of directors of Hydro One, Ontario's principal transmission company. He has an engineering degree from Michigan Technological University, a masters degree in Philosophy from York University (Toronto) and has completed graduate studies in the history and philosophy of science and technology at the University of Toronto.

Appendix B - Washington DC Workshop, Sept. 15, 2005

Final agenda and list of participants from Washington DC workshop held on September 15, 2005. Transcript can be downloaded from:

DOE website: <http://www.energetics.com/reliability.html>

Hilton Crystal City Ronald Reagan
National Airport
2399 Jefferson Davis Highway
Arlington, Virginia 22202
(703) 418-6800

September 15, 2005

Sponsored by
U.S. Department of Energy and
Natural Resources Canada

AGENDA

8:30 am

Welcome

Jimmy Glotfelty, *Workshop Facilitator*
Vice President, Energy Markets, ICF Consulting

Opening Remarks

Clay Sell, *Deputy Secretary, U.S. Department of Energy*

Overview of Workshop Panels and Format

Jimmy Glotfelty, *Workshop Facilitator*
Vice President, Energy Markets, ICF Consulting

9:00 am

Panel 1 – Blackout Causes and Role of Reliability Rules

Panelists:

- ◆ David Nevius, *North American Electric Reliability Council (NERC)*
- ◆ Kellan Fluckiger, *Alberta Department of Energy*
- ◆ Jack Casazza, *Power Engineers Supporting Truth*

Panel 1 Questions:

- ◆ The identified causes of many major past blackouts (e.g., 1965, 1977, 1996) also contributed to the August 14, 2003 blackout. How has restructuring affected these causal factors? Has it made them worse; if so, how?
- ◆ Will the U.S. Energy Legislation that was signed into law on August 8, 2005 – specifically, the call for mandatory reliability standards – prevent future blackouts? Are additional changes also needed? What are they?

10:15 am

Break

10:30 am

Panel 2 – Addressing Changing Industry Structure and the Need for Transmission Investment

Panelists:

- ◆ David Goulding, *Independent Electricity System Operator (IESO)*
- ◆ Jose Delgado, *American Transmission Company*
- ◆ Scott Thon, *AltaLink Management Ltd.*
- ◆ John Hughes, *ELCON*

10:30 am

Panel 2 – Addressing Changing Industry Structure and the Need for Transmission Investment

Panelists:

- ◆ David Goulding, *Independent Electricity System Operator (IESO)*
- ◆ Jose Delgado, *American Transmission Company*
- ◆ Scott Thon, *AltaLink Management Ltd.*
- ◆ John Hughes, *ELCON*

Panel 2 Questions:

- ◆ What impacts – both positive and negative – has electricity industry restructuring had on reliability? What are the best ways to mitigate restructuring’s negative impacts and enhance its positive impacts?
- ◆ Is greater emphasis on transmission construction appropriate in view of its contribution to the public interest in reliability? And, if so, how much extra emphasis is warranted and through what means?

12:00 pm

Lunch (*on your own*)

1:15 pm

Panel 3 – The Appropriate Role of Markets and Technology in Safeguarding the Public Interest in Reliability

Panelists:

- ◆ Andy Ott, *PJM Interconnection*
- ◆ Robert Thomas, *Cornell University*
- ◆ John Wilson, *Ontario Electricity Coalition*

Panel 3 Questions:

- ◆ Are market-based principles for organizing wholesale electricity trade limited in their ability to accommodate the public interest in electricity reliability? If so, what are the limits of these principles and what should be done to address these limits?
- ◆ What are your perspectives on the roles and limits of new technologies to address potential problems emerging from the aging workforce of the electricity industry and the reductions in manpower at utilities?

2:30 pm

Closing Remarks and Next Steps

Jimmy Glotfelty, *Workshop Facilitator*
Vice President, Energy Markets, ICF Consulting

3:00 pm

Adjourn

List of Participants – September 15, 2005, Washington, DC

Amy	Abel	Congressional Research Service
Poonum	Agrawal	U.S. Department of Energy
Sharon	Ashurst	U.S. Department of Agriculture-RUS
Miriam	Barranco	American Education Institute
Mark	Bennett	Electric Power Supply Association
Anjan	Bose	Washington State University
Carl	Bridenbaugh	FirstEnergy Services
David	Burpee	Natural Resources Canada
Michael	Calviou	National Grid
Jack	Casazza	American Education Institute
Catherine	Cash	Platts Inside Energy
Kevin	Coates	Coates Communications Consulting
Paul	Connors	Canadian Embassy
Jose	Delgado	American Transmission Co.
Charles	Durkin	Northeast Power Coordinating Council (NPCC)
Timothy	Egan	High Park Group. Inc
Joseph	Eto	Lawrence Berkeley National Laboratory
Philip	Fedora	Northeast Power Coordinating Council (NPCC)
Richard	Fioravanti	ICF Consulting
Kellan	Fluckiger	Alberta Department of Energy
Michael	Giberson	Independent
Lauren	Giles	Energetics Incorporated
Jimmy	Glotfelty	ICF Consulting
Dave	Goulding	Independent Electricity System Operator
Toru	Hattori	Central Research Institute of Electric Power Industry
Steve	Hauser	SAIC
Scott	Henry	Duke Power
Liz	Herbert	Natural Resources Canada
John	Hughes	ELCON
Vernellia	Johnson	U.S. Department of Energy
Brianne	Kohs	U.S. Department of Energy
David	Koogler	Dominion
Karen	Larsen	U.S. Department of Agriculture
Mark	Lively	Utility Economic Engineers
Rob	Martinko	FirstEnergy
Sarah	McKinley	Federal Energy Regulatory Commission
David	Meyer	U.S. Department of Energy
David	Miller	Federal Energy Regulatory Commission
Gary	Nakarado	Federal Energy Regulatory Commission
David	Nevius	North American Electric Reliability Council
Tim	Newton	Western Electricity Coordinating Council (WECC)
Gloria	Ogenyi	Conectiv
Andrew	Ott	PJM Interconnection
Phil	Overholt	U.S. Department of Energy
Raymond	Petniunas	Utility Resource Consulting

Nina	Plaushin	American Transmission Company
Steven	Pullins	SAIC
Bryne	Purchase	Bryne Purchase Strategy Group Inc
Paul	Ring	Restructuring Today
Michael	Rodrigue	U.S. Department of Energy
Tom	Rusnov	Natural Resources Canada
Mike	Schmidt	Platts Inside Energy
Clay	Sell	U.S. Department of Energy
John	Shelk	Electric Power Supply Association
Harry	Singh	Federal Energy Regulatory Commission
Merrill	Smith	U.S. Department of Energy
Julia	Souder	U.S. Department of Energy
Richard	Sweetser	Exergy Partners Corp.
Netra	Thakur	Patni Computer Systems
Robert J.	Thomas	Cornell University
Scott	Thon	AltaLink Management Ltd.
Kevin	Tomsovic	National Science Foundation
Ellen	Vancko	North American Electric Reliability Council
Rahul	Walawalkar	Carnegie Mellon Electricity Industry Center
Matthew	Wald	The New York Times
Christy	Walsh	Federal Energy Regulatory Commission
Kim	Warren	Independent Electricity System Operator
Joseph	Watson	Exelon Corporation
Peggy	Welsh	Consumer Energy Council of America
Laurel	Whisler	Salt River Project
John	Wilson	Ontario Electricity Coalition

Appendix C - Toronto, Ontario Workshop, Sept. 28, 2005

Final agenda and list of participants from Toronto, Ontario workshop held on September 28, 2005. Transcript can be downloaded from:

NRCan website: <http://www2.nrcan.gc.ca/es/erb/erb/english/conference.asp>

Toronto Congress Centre
Pierre Berton Room
650 Dixon Road
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September 28, 2005

Sponsored by
Natural Resources Canada and the U.S.
Department of Energy

AGENDA

8:30 am

Welcome

Bryne Purchase, *Workshop Facilitator*
Professor, School of Policy Studies, Queen's University

Opening Remarks

Tom Wallace, *Director General, Electricity Resources Branch, Natural Resources Canada*

Overview of Workshop Panels and Format

Bryne Purchase, *Workshop Facilitator*
Professor, School of Policy Studies, Queen's University

9:00 am

Panel 1 – Blackout Causes and Role of Reliability Rules

Panelists:

- ◆ David Nevius, *North American Electric Reliability Council (NERC)*
- ◆ David Goulding, *Independent Electricity System Operator (IESO)*
- ◆ John Hughes, *ELCON*

Panel 1 Questions:

- ◆ The identified causes of many major past blackouts (e.g., 1965, 1977, 1996) also contributed to the August 14, 2003 blackout. How has restructuring affected these causal factors? Has it made them worse; if so, how? If it has made them worse, what should be done to address them?
- ◆ Will the U.S. Energy Legislation that was signed into law on August 8, 2005 – specifically, the call for mandatory reliability standards – prevent future blackouts? Are additional changes also needed? What are they?

10:15 am

Break

10:30 am

Panel 2 – Addressing Changing Industry Structure and the Need for Transmission Investment

Panelists:

- ◆ Jose Delgado, *American Transmission Company*
- ◆ Scott Thon, *AltaLink Management Ltd.*
- ◆ Tom Welch, *PJM Interconnection*
- ◆ John Wilson, *Ontario Electricity Coalition*

Panel 2 Questions:

- ◆ What impacts – both positive and negative – has electricity industry restructuring had on reliability? What are the best ways to mitigate restructuring's negative impacts and enhance its positive impacts?
- ◆ Is greater emphasis on transmission construction appropriate in view of its contribution to the public interest in reliability? And, if so, how much extra emphasis is warranted and through what means? Is there a trade-off between transmission and generation and, if so, how should it be managed?

12:00 pm

Lunch (*on your own*)

1:15 pm

Panel 3 – The Appropriate Role of Markets and Technology in Safeguarding the Public Interest in Reliability

Panelists:

- ◆ Jack Casazza, *Power Engineers Supporting Truth*
- ◆ Kellan Fluckiger, *Alberta Department of Energy*
- ◆ Robert Thomas, *Cornell University*

Panel 3 Questions:

- ◆ Are market-based principles for organizing wholesale electricity trade limited in their ability to accommodate the public interest in electricity reliability? If so, what are the limits of these principles and what should be done to address these limits?
- ◆ What are your perspectives on the potential problems emerging from the aging workforce of the electricity industry and the reductions in manpower at utilities? What should be done to address them? What, if any, is the role of new technologies in addressing them?

2:30 pm

Closing Remarks and Next Steps

Bryne Purchase, *Workshop Facilitator*

List of Participants – September 28, 2005, Toronto, Ontario

Raj	Addepalli	State of New York, Public Service Commission
Sara	Anghel	Direct Energy
Evan	Bahry	Independent Power Producers Society Of Alberta
Peter	Bettle	Brascan Power
Robert	Blohm	NERC Ballot Body Member
François	Bouffard	McGill University
Peter	Budd	Tribute Resources Inc.
David	Burpee	Natural Resources Canada
Robert	Cary	Robert Cary & Associates Inc
Jack	Casazza	Power Engineers Supporting Truth
Karen	Clendenan	Natural Resources Canada
Tyler	Cummings	Foreign Affairs Canada
Jennifer	Drysdale	International Trade Canada
Joseph	Eto	Lawrence Berkeley National Laboratory
Jean	Finn	Government of New Brunswick
Kellan	Fluckiger	Department Of Energy, Electricity Division
Peter	Fraser	Ontario Energy Board
Bob	Gibbons	Ontario Power Authority
Jay	Giri	AREVA T&D Inc.
Brian	Gooder	Ontario Power Generation
David	Goulding	Independent Electricity System Operator
Ivan	Harvie	Natural Resources Canada
Liz	Herbert	Natural Resources Canada
John	Hughes	ELCON
Randy	Hughes	Bruce Power
Robert	Hunt	Optimal Technologies (Canada) Inc.
Eve	Jasmin	Natural Resources Canada
Peter	Kennedy	Retired
Paul	Kerr	Shell Trading - Coral Energy
Duane	Lyons	Altalink Management Ltd.
Doug	MacCallum	Ontario Ministry Of Energy
Frank	Macedo	Poweropt Inc
Chris	Mak	Maxlin Inc.
Gaetan	Martineau	International Trade Canada
Ron	Mazur	Manitoba Hydro
David	Meyer	US Department of Energy
Alexandra	Muir	Natural Resources Canada
David	Nevius	North American Electric Reliability Council
Naren	Pattani	Hydro One Networks Inc.
Linda	Poirier	Ontario Ministry Of Energy
George	Porter	New Brunswick System Operator
Bryne	Purchase	Queen's University
Pedro	Rebblon	Ontario Independent Electricity System Operator
Carolina	Rinfret	Hydro-québec
Paul	Roman	Northeast Power Coordinating Council
Joseph	Rossignoli	National Grid
Joanna	Sofield	British Columbia Transmission Corporation
Glen	Sutton	ATCO Electric
Don	Tench	Independent Electricity System Operator
Robert J.	Thomas	Cornell University, Dept. Of Ece
Scott	Thon	Altalink Management Ltd.
Tom	Wallace	Natural Resources Canada
Thomas	Welch	PJM Interconnection
John	Wilson	Ontario Electricity Coalition
Mike	Yealland	IESO

Appendix D - Public Comment

Public comment received on DOE and NRCan websites

Comments Posted on the Competition and Reliability in North American Energy Markets Web Forum (as of November 7, 2005)

Category: Postings on General Comments on Overall Process/Workshops Forum

Overall Impression of Papers (Richard Sedano)

I am addressing all the papers.

I see nothing distinct in these papers about the connection of distributed resources to reliability, or more generally, the value of a process that plans the transmission, displays to all the needs of the system, and then provides financial support in consideration of the reliability value to the best resources that address reliability concerns.

As a result, collectively, the papers focus primarily on the same old issues of big markets and big organizations managing them and not about little, and well-placed resources that collectively may make a much more compelling reliability contribution, and avoid exacerbating reliability problems.

Exceptions and almosts

I almost thought Dave Goulding would get to these, but his discussion about local solutions was just an effort to set limits on how standard standard market design should be.

And his discussion appropriately argues for an inclusive process, but he is talking about stakeholders and policy, and not about an unbiased resource mix.

His talk about consumer education is good, but what are we educating them about, if the wholesale market rules do not value resources that they can buy or influence directly?

His discussion about metering is provocative, but he does not really connect it to a way that retail regulators (PUCs) can make choices to encourage these investments *for reliability purposes*.

Generally, his customer focus is appreciated, compared with the other papers, but it fails to make the link to the customer resources that can be an important contributor to resource adequacy and to stability.

The tart approach from John Wilson gave me some hope, but his spotlight was trained on other targets.

While I suspect that if the improvements advanced by Casazza, et al, were implemented, a sound, risk-aware system to include targeted and distributed resources in reliability planning would be adopted, they stop well short of discussing or advocating this detail and their views on this point are unstated.

Observation

MADRI is an instrument to develop ideas along these lines, though its wires focus is more on distribution.

There is also reason for hope that some of the western planning efforts underway now might head in this direction, though the path of this work is far from certain.

Comment

My comment is that this collection of papers does not consider important possible resources to support reliability and manage risk, to wit:
a new and dramatically increased level of focus on planning from the customer perspective, using investment in customers (i.e. distributed generation, demand response, and energy efficiency) to reduce growth and therefore the impetus for transmission system instability and inadequate resources, using investment in high growth places (even in large scale generation) for the same purposes, delivering value from system benefits to these resources in the same way as system benefits support transmission resources, signaling in some partnership with state regulators places where ratesetting and investment policies under state control can support reliability goals, including the use of distributed resources, advanced metering infrastructure, and dynamic pricing.

A futurist might note that for all the discussion of the 2003 Blackout, its causes and what to do about it, as long as the US and Canadian power system is characterized by increasingly unstable geographic imbalances between load and supply, and as long transmission lines are expensive to build in terms of dollars, and, perhaps more important, in terms of the goodwill that citizens maintain about how their institutions make decisions about their financial and natural resources, the power system will continue to be vulnerable, no matter how sophisticated the network becomes, and that the answer involves steering the system to a more stable, more sustainable

configuration that is far less prone to experience the seismic build-up of events that were released in August 2003.

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Connection to Generation Siting (Richard Sedano)

I want to add a comment concerning restructuring and generation siting. As part of restructuring, many states decided that generation siting is a market-driven activity, so that beyond environmental compliance, no further evaluation criteria were applicable to permitting construction. The 2003 Blackout indicates that the interaction between unmanaged generation additions and the existing grid with its existing load patterns can make the grid more vulnerable to instability.

The answer is for states to take responsibility to consider the transmission system effects of new generation, and to make sure that new generators take responsibility for any adverse effects. Where there are RTOs or "tight pools," this should be happening in due course, though some assessment of performance by an outside reviewer would be valuable. I refer readers to the comments of Jerry Smith of the Arizona PSC during the NTGS comment period.

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Pricing Unscheduled Flows as a Way to Get Competition to Enhance Reliability: A Response to Solicited Issue Papers on Reliability and Competition (Mark B. Lively) (PDF available on web site)

Pricing Unscheduled Flows as a Way to Get Competition to Enhance Reliability: A Response to Solicited Issue Papers on Reliability and Competition

Mark B. Lively, Consultant
Utility Economic Engineers
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"We must all hang together, or assuredly we shall all hang separately." Ben Franklin, 1776 July 4, comment attributed to him upon the signing of the *Declaration of Independence*

"Due to the interconnected nature of the grid, transmission operators within each interconnection are essentially hostages to one other; if one fails to do the right thing, all others suffer the consequences." José Delgado in "The Blackout of 2003 and its Connection to Open Access"

The free flowing nature of our AC system permits unscheduled flows of electricity, a concept that can be called tie-riding. Tie-riding results in high reliability at low cost. But because we do not yet charge for tie-riding, we have freeloaders. Freeloaders can be considered to be those participants who, on balance, ride the ties more than they support the system. However, identifying that balance has proven to be elusive for the industry in the context of a competitive market. These freeloaders have caused competition to degrade reliability.¹

The problem is not the physical grid. Nor is the problem the unscheduled flows that result from the physical grid. Instead, the problem is that industry has not implemented a method to price unscheduled flows of electricity in a way that participants are paid for their geographically differentiated real time contribution to the reliability of the grid. Instead, participants are allowed to freeload by riding the ties at no charge.

¹ See "Tie Riding Freeloaders--The True Impediment to Transmission Access," *Public Utilities Fortnightly*, 1989 December 21.

Investors put money into utilities to make a profit. Some people have described these investments as being related to either economics or to reliability. Investments for economic purposes obviously should be making money for investors. The electric industry needs a way for **reliability driven investments to make money** for investors. The industry should pay for unscheduled flows of electricity using operating reliability indices to set the prices for these unscheduled flows. That requires better revenue accounting mechanisms to pay for the unscheduled flows, especially the unscheduled flows that improve reliability. The result will be that tie-riders don't get away with freeloading.²

RELATING TO THE COMMENTS IN THE PRINCIPLE PAPERS

The physics of the electric grid facilitates allow what economists call the "externalization of internalities," getting other participants to help with one's problems, especially without paying for that help. As José Delgado, President & CEO, American Transmission Co., said in "The Blackout of 2003 and its Connection to Open Access"

(d)ue to the interconnected nature of the grid, transmission operators within each interconnection are essentially hostages to one other; if one fails to do the right thing, all others suffer the consequences.

Certainly, Mr. Delgado's comments echo the famous words of Ben Franklin, "We must all hang together, or assuredly we shall all hang separately." Under the historic mode of operation, utilities treated each other as members of an Old Boys Club.³ Restructuring was meant to change the Old Boys Club, by making the industry more nearly a competitive market.

THERE SHOULD BE PROFIT

Jack Casazza, Frank Delea, and George Loehr in "Contributions of the Restructuring of the Electric Power Industry to the August 14, 2003 Blackout" frequently refer to immediate profits as the antithesis to long term reliability. These points may be valid under the current system, where participants can be freeloaders by riding the ties with no payment for doing so. However, when participants pay for externalizing their internalities there will be a way for others to earn the needed immediate profits while improving reliability.

² See "Power Crisis: Revenue Accounting Needed: An Issue Paper on the U.S. Northeastern Blackout, August 14, 2003," *Energy Pulse*, http://www.energypulse.net/centers/article/article_display.cfm?a_id=521, 2003 October 28.

³ See "Inadvertent Interchanges -- A New Way to Price Unscheduled Electricity," *Electrical World*, December 1991 and "Competition Versus the Good Old Boys' Club," Forum, *IEEE Computer Applications In Power*, January 1997.

In a similar manner, John Wilson on behalf of Ontario Electricity Coalition in "Sinister Synergies: How Competition for Unregulated Profit Causes Blackouts" told of the new owner of a hydroelectric facility draining the storage behind the dam to make a profit in a way that decreased electricity reliability. Similarly, Dave Goulding, President and CEO of the Independent Electricity System Operator of Ontario, Canada, repeated this allegation in "Competitive Power Markets and Grid Reliability: Keeping the Promise" as

(s)hort-term profit maximization in competitive electricity markets will lead firms to run their equipment too long and hard or to cut costs in potentially irresponsible ways, thereby impairing reliability.

Reliability issues should be included in the setting of prices for unscheduled flows of electricity. Such reliability driven prices would provide incentives for operators to balance profit **today** with possible profit **tomorrow** when reliability might be threatened even more. A side effect of such immediate profits will be allegations of gouging, whether the profits occur today or the profits occur tomorrow.

Mr. Delgado suggests a certification process for officials. Mr. Delgado's idea is based on the fact the new leaders in the electric industry are businessmen, not engineers. Perhaps the problem is that the electric industry needs instead to develop a business model that conforms to the industry's reliability concepts, a business model that the businessmen can understand. Considering the political mandates for markets, the industry should develop a business model that reflects our most valuable product, reliability.

RELIABILITY DRIVEN PRICES

As mentioned before, Mr. Wilson and Mr. Goulding both commented about how profits today jeopardized system reliability later. The conflict between profits and reliability need not exist. Reliability concerns can be used to drive the price for unscheduled flows of electricity. High prices during periods of high concern about reliability make the profit concern match the reliability concern.

Phillip G. Harris of PJM Interconnection LLC wrote "Relationship between Competitive Power Markets and Grid Reliability: The PJM RTO Experience" in which he decried the lack of methods to measure bulk operating reliability, pointing to SAIDI and SAIFI as ways to measure distribution operating reliability. But these are after the fact measurements. Conversely, the standard bulk reliability index is one day in ten years, which is a planning index.

In contrast to Mr. Harris complaint about the lack of operating reliability indices, John P. Hughes of the Electricity Consumers Resource Council pointed to

NERC's investigation of frequency excursions in "Reliability Risks During the Transition to Competitive Electricity Markets." Frequency is indeed a way to measure the operating reliability of the bulk power system. NERC's Joint Inadvertent Interchange Task Force even said that frequency should be used as a way to modify LMP to reflect reliability issues. But NERC has not led the industry to act on the recommendations of NERC's own task force.

Mr. Wilson has decried the decrease in joint planning and coordination. That decrease in cooperation may be true on a planning basis, but the AC nature of the electric system results in everyone seeing the same frequency, at least so long as the system hangs together. The industry needs to take advantage of this coordinated frequency as a reliability measurement in the process of setting prices for unscheduled flows of electricity.

A second reliability measure is voltage. Voltage is not consistent throughout the network, as was demonstrated by Robert J. Thomas, Professor, School of Electrical and Computer Engineering, Cornell University in "Managing Relationships Between Electric Power Industry Restructuring and Grid Reliability." Prof. Thomas presented figures he reproduced from a presentation by Terry Boston, a vice president at Tennessee Valley Authority. The voltages vary across the map but are consistent on either side of the meter separating two utilities. This can be used to set the price for reactive power delivered between parties.

David R. Nevius and Ellen P. Vancko of North American Electric Reliability Council urge mandatory reliability standards in "Ensuring a Reliable North American Electric System in a Competitive Marketplace." A better approach would be to use reliability measurements to set the price for unscheduled flows of electricity. This concept was supported by NERC's own Joint Inadvertent Interchange Task Force. In some respects, imposing mandatory reliability standards is like legislating morality. It didn't work for prohibition and is unlikely to work for electricity. A better approach is an appropriate structured "sin tax", such as a payment for unscheduled flows of electricity.

In many respects, reliability measurements can be considered to be the public goods discussed by Prof. Thomas. Prof. Thomas pointed specifically to spinning reserve as a public good for which many market participants believe they should not have to pay. But reserves can be treated as an insurance product, with real time charges to those participants who draw on spinning reserves without being a participant in the insurance pool.⁴ This is an explicit example of how to develop a business model for a reliability issue.

⁴ See "Metrics for Operating Reserves," *The National Regulatory Research Institute Quarterly Bulletin*, Spring 1998. This paper was the prepared remarks at the Secretary of Energy Advisory Board Task Force on Electric System Reliability meeting of 1998 January 13.

GEOGRAPHIC DIFFERENTIATION

Payment for unscheduled flows of electricity should include the payment for the use of transmission lines and for reactive power. Since reactive power “doesn’t travel far”, payment for unscheduled flows of electricity will necessarily be locational. Similarly, payment for the use of transmission lines would reflect the difference between the value of the power entering the lines versus the power leaving the lines. This requires locational prices.

Mr. Harris also wrote that locational marginal prices (LMP) would have revealed the problems in Northeastern Ohio in time to have prevented the August 2003 blackout. Unfortunately the seams agreement between PJM and its neighbors do not include a provision for LMP for the loop flow existing between and among PJM and its neighbors. Just having LMP prices in Northeastern Ohio would not have been sufficient unless PJM were willing to pay First Energy for the loop flow through PJM coming from First Energy.

Mr. Goulding points out that Ontario prohibits geographically differentiated prices, an important aspect of LMP. During the few minutes before the August 2003 blackout, Ontario provided a transmission path for significant amounts of loop flow.⁵ A payment mechanism for unscheduled flows of electricity would have compensated Ontario for its efforts to keep the system together, whether those efforts were intentional or the efforts were unintentional. That the efforts were unintentional and merely the results of the physics of the system can be presumed from the description of the surges of electricity through the Ontario system. That they were merely the results of the physics of the system does not detract from the payments Ontario would have gotten under a system of payment for unscheduled flows of electricity.

Mr. Hughes has claimed that “organized markets” have increased congestion, especially for the systems adjacent to those “organized markets,” a concept called loop flow, or parallel path flow in special cases. In regard to parallel path flow, Mr. Hughes cited the calls for Transmission Line Loading Relief (TLR) on NIPSCO associated with AEP joining PJM. Mr. Hughes also discussed the potential for a difference between transmission investments made for economic reasons versus those made for reliability reasons.

Also, “Keeping the Lights On: An Insurance Industry Model . . . to Stop Manipulation,” *Public Utilities Fortnightly*, 2002 July 1.

⁵ See “Power Crisis: Revenue Accounting Needed: An Issue Paper on the U.S. Northeastern Blackout, August 14, 2003,” *op. cit.*

Kellan Fluckiger, Alberta Department of Energy, in "Competitive Electric Power Markets and Grid Reliability, something has changed over the past decade!" raised the issue of merchant power lines, which former FERC Commissioner Wood believes should achieve rate recovery. The previously mentioned parallel path flow is one of the impediments to merchant power lines achieving rate recovery. Tariff differentials on competing parallel paths result in over scheduling on the path with cheaper fixed tariffs and with overloads on the more expensive path. LMP for unscheduled flows on all lines, including the overloaded lines, would reduce the incentive for owners of parallel paths to over schedule the use of their lines.

Mr. Fluckiger's concept of merchant power lines may be difficult to implement in his province of Alberta. Scott Thon of AltaLink wrote "Alberta Electric Industry Restructuring, Implications for Reliability" in which he describes the provincial decision against LMP. LMP is a market approach which can encourage merchant power lines. However, Mr. Thon also wrote of the decision that the province would seek to minimize the cost of transmission constraints. Such a policy can result in transmission lines being built as rental properties instead of competing in an LMP based market.

REACTIVE POWER

Complicating the LMP issue in regard to the August 2003 blackout is that a major problem was the reactive power necessary for voltage support. There is now no mechanism in place to pay for reactive power on a locational real time basis, especially the unscheduled flow of reactive power. "Principles for Efficient and Reliable Reactive Power Supply and Consumption," the 2005 February 4 staff report that began FERC Docket AD05-1, only discusses paying for the investments related to the ability to produce reactive power, not LMP for reactive power.⁶

Prof. Thomas wrote

(e)lectric 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

⁶ See "Wide Open Load Following: Mark Lively's Approach to Pricing Reactive Power," *Carnegie Mellon University Electric Industry Center Luncheon Seminar*, 2004 December 2, as modified from a presentation to FERC Staff on 2004 October 25 as a member of the IEEE-USA Energy Policy Committee, and "Comments Of Mark Lively, Utility Economic Engineers, Including Answers And Comments To Questions In Staff Report Of 2005 February 4," filed in *Principles for Efficient and Reliable Reactive Power Supply and Consumption*, FERC Docket No. AD05-1-000, 2005 April 4.

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.

In practice, there are now only two measurable commodities, active power and reactive power.⁷ All other products discussed by Prof. Thomas can be shown to be hedges against the delivery of these two commodities.⁸ Indeed, the insurance model discussed earlier with respect to operating reserves can be considered to be a hedge.

Mr. Goulding made a point that participants in most of the developed markets have an opportunity to hedge their purchases. That opportunity has been severely restricted in most of the restructured markets. One of the best ways that utilities and their customers have found to hedge against market volatility has been the outright ownership of power plants. This right has been denied major utilities in the restructuring process. A second common method to hedge against volatile prices has been long term contracts with a vertically integrated utility, such as those contracts signed by municipal utilities and cooperatives with local investor owned utilities. Again, this right has been denied major utilities in the restructuring process.

CONCLUSIONS

There needs to be a way for the industry to make a profit. Reliability can be enhanced if we connect prices for unscheduled flows of electricity to concurrent reliability indices. These reliability indices need to be geographically differentiated and reflect the effect on reactive power.

NOTE: The articles published in *Public Utilities Fortnightly* are copyrighted by Public Utilities Reports. A limited number of reprints are available from the author. Other cited articles are available for free download at www.LivelyUtility.com.

⁷ See "Thirty-One Flavors or Two Flavors Packaged Thirty-One Ways: Unbundling Electricity Service" *The National Regulatory Research Institute Quarterly Bulletin*, Summer 1996. This article originally appeared as comments titled "31 Flavors or Two Flavors Packaged 31 Ways," *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities*, FERC Docket RM95-8-000, 1995 November 2.

⁸ Note that the growing concern about power quality may result in the third harmonic (at 180 Hertz) being treated as a commodity, or the fifth harmonic (at 300 Hertz). Both can be considered to be special cases of reactive power.

Submitted November 4, 2005

EPSA Comments on September 2005 Technical Workshops on Competition and Reliability in North American Energy Markets

The Electric Power Supply Association (EPSA) applauds the cooperative efforts of the U.S. Department of Energy (DOE), Natural Resources Canada (NRC) and the Federal Energy Regulatory Commission (FERC) to ensure the reliability of the North American wholesale power grid by addressing the recommendations following the August 14, 2003 blackout. Especially important is the need to better understand the mutually reinforcing relationship between system reliability and competitive markets. EPSA has been contributing to this effort through its active participation in the North American Electric Reliability Council (NERC), and by providing input on FERC's policy statement on reliability.

EPSA representatives attended the DOE/NRC technical workshop conducted in Arlington, Virginia on September 15, 2005. EPSA is particularly encouraged by statements made by Deputy Energy Secretary Clay Sell, as well as the presenters of numerous white papers, concluding that reliability and competitive markets are compatible. In fact, these conclusions are consistent with findings by the U.S.-Canada Power Systems Outage Task Force, the North American Electric Reliability Council (NERC) and other credible studies on the August 2003 blackout.

As the experience of regional grid operators has demonstrated, not only are competitive markets consistent with reliability, but they also support and promote system security. The record of the competitive power sector in improving transmission system operating reliability has been equally impressive. Because consumers and load-serving entities need a reliable bulk power system to provide them access to the most efficient or preferred sources of supply, and because competitive suppliers need a reliable grid in order to satisfy that consumer demand, the competitive power sector is fully committed to maintaining grid reliability.

Between 1993 and 2003, the competitive generation sector added approximately 187,000 megawatts of generating capacity to the U.S. grid, providing a significant degree of supply adequacy to the reliability equation. Further, competitive forces have improved grid reliability by reducing equivalent forced outage rates, reducing maintenance down-time, increasing capacity factors of traditional base

operations management, and creating efficient, market-based congestion management protocols that are superior to and more efficient than the blunt instrument of transmission line-loading relief.

EPSA and its member companies look forward to continuing their work with DOE, FERC, NERC, the Regional Reliability Councils, the RTOs, the North American Energy Standards Board, energy policymakers and other stakeholders to improve the essential link between reliability and competitive power markets and their mutually beneficial operation. The first task is the creation of the Electric Reliability Organization and implementation of the reliability provisions of the Energy Policy Act of 2005. EPSA welcomes the opportunity to contribute to these efforts.