INTERNATIONAL ENERGY AGENCY

ENERGY MARKET EXPERIENCE

LEARNING FROM THE BLACKOUTS

Transmission System Security in Competitive Electricity Markets

OECD

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FOREWORD

Electricity market reform has fundamentally changed the environment for maintaining reliable and secure power supplies. Growing inter-regional trade has placed new demands on transmission systems, creating a more integrated and dynamic network environment with new real-time challenges for reliable and secure transmission system operation. These operational challenges are intensified as spare transmission capacity is absorbed.

The major blackouts of 2003 raised fundamental questions about the appropriateness of the rules, regulations and system operating practices governing transmission system security. Despite the considerable efforts since 2003 to address the weaknesses exposed by the blackouts, it can still be argued that the development of these rules and operating practices have not kept pace with the fundamental changes resulting from electricity market reform. More can and should be done.

Management of system security needs to keep improving to maintain reliable electricity services in this more dynamic operating environment. The challenges raise fundamental issues for policymakers.

This publication presents case studies drawn from recent large-scale blackouts in Europe, North America, and Australia. It concludes that a comprehensive, integrated policy response is required to avoid preventable large-scale blackouts in the future.

The legal and regulatory arrangements governing transmission system security can be enhanced. In particular, scope exists to clarify responsibilities and accountabilities and to improve enforcement. System operating practices need to give greater emphasis to system-wide preparation to support flexible, integrated real-time system management. Real-time coordination, communication and information exchange, particularly within integrated transmission systems spanning multiple control areas, can and must be improved.

Effective real-time system operation requires accurate and timely information and state-of-the-art technology to facilitate effective contingency planning, system management and coordinated emergency responses. New and existing technology could be more fully employed to enhance effective system operation. Appropriate training is also required to enhance emergency responses. More effective asset and vegetation management can also make a valuable contribution to strengthen transmission system security.

An effective policy response should also consider how best to employ market-based approaches to complement regulatory arrangements to strengthen transmission system security at least cost.

Governments should provide the leadership and drive needed to establish effective, coordinated processes that address the key policy issues in an integrated and comprehensive manner. At the same time, all stakeholders need to work together to address these challenges if we are to avoid unduly exposing transmission systems to the risk of further substantial power failures.

This book is part of the Agency's *energy market experience* series. It is published under my authority as Executive Director of the International Energy Agency.

Claude Mandil
Executive Director

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EXECUTIVE SUMMARY

Modern economies are becoming increasingly dependent on reliable and secure electricity services. The substantial supply disruptions that struck North America and Europe during 2003 clearly demonstrated the fundamental importance of transmission networks for the efficient and secure operation of electricity markets and highlighted their vulnerability to transmission network failures. While large blackouts are by no means a new phenomenon and have happened in the past before electricity reform, these disruptions created considerable public concern, with some claims that electricity reform had reduced electricity system reliability. Growing public sensitivity to supply disruptions reflects the increasing dependence of modern economies on reliable and efficient electricity supplies, and adds to the pressure on governments to effectively address reliability issues.

This study explores policy issues associated with the system security dimension of reliability, with a particular focus on transmission system security in competitive electricity markets. System security refers to the ability of a power system to withstand the unexpected loss of key components. This can be thought of as the operational dimension of electricity reliability. This work draws on case studies of recent large-scale blackouts involving the failure of transmission systems to help identify key lessons for policymakers. Issues associated with the adequacy of transmission infrastructure and investment to meet growing demand for transmission services in electricity markets is addressed in the IEA publication *Lessons from Liberalised Electricity Markets*, which examines key lessons for policymakers from liberalisation in IEA member countries over the last decade.

Electricity Reform Creates New Challenges for Maintaining Transmission System Security

Electricity reform has brought more efficient use of transmission systems and greater regional integration of power flows resulting from inter-regional trade. The many benefits flowing from electricity reform are discussed in the IEA publication *Lessons from Liberalised Electricity Markets*. Greater integration has helped to improve overall transmission system security by permitting more effective reserve sharing. It has also helped to reduce transmission system security costs. Growing demand for transmission capacity to accommodate inter-regional trade means that transmission systems are increasingly being run at or near their security limits.

Electricity market reform has also brought unbundling and independent, decentralised decision-making. As a result, decisions affecting network operation and performance that were once made in a centrally coordinated way within vertically integrated utilities are now made by many independent market participants. Decentralised decision-making has fundamentally changed utilisation of transmission networks. Previously stable and relatively predictable patterns of network use have in many cases been replaced with less predictable usage, more volatile flows and greater use of long-distance transportation, reflecting growing inter-regional trade.

New patterns of transmission network use are creating a far more complex and dynamic operating environment, with real-time monitoring and management by system operators becoming more and more crucial for maintaining transmission system security. At the same time, unbundling has reduced system operators' capacity to manage system security through coordinated actions across the value chain. The emergence of regional markets that span multiple control areas has added to the transmission system security challenge by increasing each system operator's exposure to the operational decisions of other system operators and to potential failures outside their control area.

In this more integrated and dynamic operating environment, an event affecting a relatively distant part of a transmission system may have greater potential to spread and severely disrupt the supply and operation of electricity markets.

A Comprehensive and Integrated Policy Response is Needed

Despite these fundamental changes, development of regulatory arrangements, reliability standards and system operating practices relating to transmission system security generally have not kept pace with the new real-time system operating challenges resulting from electricity market reform. The major blackouts of 2003 and 2004 raised searching questions about the appropriateness of existing regulation, rules and practices in this new operating environment. Examination of these matters is being undertaken in the wake of these disturbances, but the focus has been relatively technical. Failures of the kind experienced in 2003 and 2004 also raise more strategic issues for policymakers.

The new challenges are interrelated, requiring a comprehensive, integrated policy response if they are to be successfully addressed. An effective policy response must address the many policy dimensions of transmission system security in competitive electricity markets including: legal, regulatory and structural arrangements; technical standards; operating practices; coordination, communication and information exchange; training; application of technology; asset management; and vegetation management. It should also consider how best to employ market-based approaches to complement regulatory arrangements to strengthen transmission system security.

All key stakeholders whose actions affect transmission system security must be involved in this process, because unbundling effectively makes maintaining system security a shared responsibility that needs to be precisely allocated among the parties involved. Key stakeholders in this context will include governments, system operators, transmission owners, regulators, and market participants. Governments are well placed to provide the leadership and drive needed to establish an effective and coordinated process that addresses the key policy issues in an integrated and comprehensive manner.

Inadequate responses to these issues are likely to encourage overly conservative management of transmission capacity at the expense of efficient inter-regional trade, and possibly leave interconnected networks unduly exposed to the risk of further substantial power failures.

Legal, Regulatory and Structural Framework

Legal and regulatory arrangements provide the foundation for establishing effective governance and incentive structures for transmission system security in competitive markets, replacing previous substantial reliance on reliability obligations placed on local, vertically integrated utilities. The case studies highlight the failings of poorly defined governance arrangements and the importance of clarifying roles, responsibilities and accountabilities within a legal framework that provides comprehensive coverage and enables effective enforcement. An effective legal and regulatory framework should:

- clarify individual and shared responsibilities for transmission system security;
- align accountabilities with the new functional responsibilities resulting from unbundling;
- ensure the boundaries of authority to act are specified for each party, and that parties have sufficient authority to undertake their responsibilities within those boundaries;

- provide strong incentives for effective coordination and information exchange, within the value chain and across systems spanning multiple control areas, reflecting the shared nature of responsibility for aspects of transmission system security;
- create transparency and objectivity, given the potential commercial implications of system operators' actions in competitive electricity markets;
- strengthen coverage, accountability and enforcement, where necessary, to help reinforce incentives for providing appropriate levels of transmission system security, and to build the credibility of the regime;
- be applied consistently across an integrated transmission system; and
- balance market requirements for access to transmission capacity with transmission system security requirements.

Regulatory arrangements need to be independent, with regulatory processes characterized by transparency, objectivity and consistency. An institutional framework based largely on industry self-regulation is no longer considered credible by market participants in competitive electricity markets. Concerns have been raised about the independence and objectivity of such arrangements. Conflict of interest could compromise the development, application and enforcement of system security rules, or lead to inertia as competing interests are unable to resolve rule-making issues in a timely or effective manner.

Independence could be addressed by allocating regulatory responsibility for transmission system security functions to existing industry regulators. However, economic regulators may not possess sufficient technical competence to effectively verify and enforce compliance with transmission system security requirements. A careful balance is required to ensure independence and competence.

Structural arrangements that promote independence, transparency and objectivity will reinforce the legal and regulatory regime. Independence and objectivity can be strengthened by ownership unbundling of system operating functions from contestable components of the value chain. Ownership unbundling would help to reinforce incentives for transparent and non-discriminatory behavior that are more closely aligned to efficient management of system security and market-based dispatch. It would also remove any related conflict of interest that could influence operator interventions and possibly adversely affect transmission system security. Ownership unbundling of system operation functions would enhance the real, and perceived, credibility of system operation in competitive electricity markets.

Exposure to legal liability can help strengthen incentives for effective system operation. However, the nature and scope of legal liability needs to be clearly specified and consistent with system operators' functional responsibilities in unbundled electricity markets. Excessive or poorly defined liability may encourage conservative practices which could undermine effective emergency responses. This is a particular issue in the context of load shedding practices. A regime of limited liability would allow for an appropriate balance between commercial discipline and encouraging appropriate actions to manage an emergency event.

Transmission system security can be strengthened through greater aggregation of regulatory and system operating functions across integrated transmission systems spanning multiple control areas. A single independent system operator with a holistic, real-time perspective of an integrated transmission system and with sufficient resources to manage credible emergency events is in a strong position to effectively respond to such events in a manner that minimizes their overall impact. Similarly, a single regulatory structure would facilitate transparent, objective and consistent monitoring and enforcement across an integrated transmission system. However, there may be legal, technical and organizational challenges that create practical barriers to aggregation in some cases. Effective coordination of system operation and regulatory activities becomes particularly important in the absence of more aggregated structures.

Transmission System Security Standards

Operational standards applied to manage transmission system security have changed little since the introduction of electricity market reform, with great reliance placed on the N-1 standard[1]. The standard is typically applied in a deterministic way that does not take account of the probability of a failure occurring or the impact of potential failures.

The blackouts raised questions about how these standards are interpreted and applied. Improved compliance with existing standards may not address the fundamental appropriateness and effectiveness of those standards in reformed electricity markets. Applying more onerous standards would generally increase the level of transmission system security within an integrated transmission system, but at great cost.

1. *A power system can be described as being N-1 secure when it is capable of maintaining normal operations (ie. reliably delivering electricity of a given frequency and voltage subject to technical limits) in the event of a single credible contingency event, like the loss of a transmission line, generator or transformer.*

Probabilistic methodologies, such as probability risk assessment[2], could be used to enhance existing standards, providing a more flexible and adaptable operational standard that better reflects more dynamic, real-time operating conditions. Probabilistic approaches could be refined to incorporate a measure of the potential cost and benefits associated with a given level of system security. This could enable more responsive management of system security reflecting the value markets may place on secure electricity services. Technologies that improve real-time system information and that enable operators to directly control power flows over particular transmission lines would increase the potential for using probabilistic methods to augmenting existing standards.

Coordination, Communication and Information Exchange

Operating practices need to more fully reflect the dynamic and regionally integrated operating environment resulting from electricity reform. In particular, operating practices need to be flexible and adaptable to permit effective real-time responses to system emergencies and disturbances. Contingency planning and emergency responses need to be undertaken from a whole-of-system perspective, reflecting the shared nature of responsibility and actions required to maintain transmission system security, particularly in integrated transmission systems spanning multiple control areas.

Effective coordination, communication and information exchange is vital in this context. Interaction between control areas needs to move beyond day-ahead information exchange and exception based coordination closer to real time. Coordinated real-time security assessment and control is required. Multilateral agreements covering all control areas within an integrated transmission system need to be implemented to ensure, among other things, holistic operational contingency planning and to provide agreed protocols for coordinated action in the event of an emergency situation. Some progress has been made in these areas, however, scope exists to enhance and strengthen these arrangements.

Coordinated management of transmission system security needs to be supported by real-time data exchange and communication. Accurate, real-time information is required to support effective contingency preparation and

2. *Probability risk assessment (PRA) involves identifying initial events and possible sequences of related events that can lead to system failures, and estimating the total probability of these events occurring. PRA essentially involves calculating a measure of the probability of undesired events on the transmission system and a measure of the severity or impact of those events. PRA has been successfully applied in several industries with complex engineering systems that are exposed to low probability, high consequence failures.*

emergency responses. Information also needs to provide a holistic picture of an integrated transmission system, to support effective, coordinated management of system security. Greater harmonization of data standards would improve the quality of information, and promote more effective information exchange between system operators within an integrated transmission system.

Communication strategies also need to be developed to ensure effective information dissemination to other key stakeholders, such as governments and the community, during emergencies and system restoration.

Governments should examine existing coordination, communication and information exchange arrangements with a view to improving and strengthening them as appropriate.

Investing in Technology

Development and deployment of new and existing technologies has considerable potential to improve system operating tools to enhance transmission system security. Technology can improve the accuracy, quality and timeliness of information and support the development of more accurate and dynamic system modeling. This, in turn, would support more flexible and adaptable contingency preparation and promote greater real-time situational awareness. Technology may also improve effective operator control over power flows, which would permit more flexible operation of transmission systems and more effective real-time responses to alleviate congestion, manage emergency situations, and enable timely service restoration. Furthermore, it offers the potential to facilitate real-time coordination and more holistic management of system security in transmission systems spanning multiple control areas.

A number of new technologies are under development which will contribute substantially to improve transmission system management in terms of increasing flexibility and security. Integrated deployment of technologies has the potential to substantially improve transmission system flexibility and resilience while enabling more innovative solutions to improve reliably, power quality and market efficiency.

Technology, however, should not be viewed as a 'magic bullet'. An appropriate balance between automatic and human control needs to be maintained, such that technology supports effective system operation and does not become a substitute for it.

Regulatory or institutional barriers to efficient development and deployment of cost-effective technologies need to be identified and removed. Effective processes will be needed to test and validate new technologies, to help reduce uncertainty and deployment risks. Governments should support the development of such processes. They could also consider providing assistance for promising areas of research and development, where appropriate. Any assistance should be provided in a framework of strong cooperation with industry to ensure that outcomes are efficiently and effectively deployed.

Investing in People

Highly trained and experienced personnel are required to manage transmission system security in the more dynamic real-time operating environment created by electricity reform. More attention has focused on emergency training in the wake of the 2003 blackouts. Training programs are being implemented based on emergency simulations to sharpen these skills.

However, new training programs may be needed in this new operating environment. Competencies required to successfully manage transmission system security in liberalized electricity markets need to be identified and training programs reviewed to ensure that they equip system operators for the more dynamic real-time operating challenges associated with electricity markets. Joint training programs should be developed to facilitate more effective coordination among system operators managing an integrated transmission system.

Training could also be extended to other relevant professionals involved in supporting secure system operation. These could include personnel managing related information technology and other technical or engineering staff. Training might also be extended to other parties whose actions could affect transmission system security, such as generator plant operators and technical regulators.

Asset Performance and Maintenance

Transmission system security is fundamentally dependent on predictable and reliable asset performance. Innovative maintenance practices should be applied where possible. Condition-based monitoring, for example, could be used to target and optimize maintenance efforts, to reduce maintenance down time while also minimizing the risk of component failure at least cost. Coordination of maintenance cycles across integrated transmission systems would further improve transmission system security by minimizing the impact of scheduled line outages on available transmission capacity.

The case studies highlight the need for effective verification and enforcement to ensure that equipment is properly maintained and operates predictably, particularly during emergency situations. Maintenance requirements and performance standards should be reviewed, with a view to clarifying standards and strengthening verification and enforcement regimes as appropriate. Protection settings also need to be reviewed to ensure that they provide an appropriate balance between equipment protection and reliable system operation.

Regulators need to be mindful of the potential impact of regulatory decisions on incentives for efficient asset management. Regulatory outcomes need to allow adequate cost-recovery for prudent maintenance.

Vegetation Management

Contact with trees is one of the most common causes of transmission line failure and was a key cause of the major blackouts in North America and Italy in 2003. Effective vegetation management is critically important for maintaining transmission system security.

Transmission owners should establish formal vegetation management plans based on accurate information about the vegetation under and adjacent to transmission lines. Field inspections of vegetation conditions should occur on a frequent basis, with the inspection schedule based on anticipated growth. Easements should be maintained in accordance with environmentally sound control methods that minimize the potential for fast-growing trees to take root under or adjacent to transmission lines.

Vegetation management standards need to be reviewed, with a view to creating clearer, more consistent and enforceable standards where possible. However, considerable variation can occur in vegetation and climatic conditions affecting easements, which may practically preclude absolute prescription in this context. A balance will need to be struck between flexibility to accommodate local variations and certainty to permit effective verification and enforcement.

Regulatory arrangements should also be reviewed to remove potential duplication, resolve conflicting requirements, and to streamline regulatory approval processes for undertaking vegetation management. Vegetation management is an expensive exercise and regulators need to ensure that regulatory arrangements permit recovery of prudent expenditures.

Market-based Approaches can Enhance Transmission System Security

In general, markets encourage more flexible and responsive use of the transmission system, which has the potential to complement system operator management of transmission system security by reducing pressures on transmission resources at times when systems are congested and operating at or near their security limits. Market-based mechanisms also allow more efficient, innovative and better targeted provision of transmission system security at least cost, and help improve the flexibility and efficiency of transmission system security management.

Significant benefits have already been achieved from market-based procurement of certain ancillary services. Commercial arrangements have led to a substantial reduction in the overall cost of ancillary services for maintaining transmission system security in United Kingdom, United States, Scandinavia and Australia. They have also allowed for more coordinated and transparent management of shared system security responsibilities in the Nordic market.

Opportunities to extend market-based approaches for purchasing ancillary services should be examined. For example, market-based procurement could be expanded to include a wider range of ancillary services, such as more effective coverage of network control ancillary services like reactive power. Potential may also exist to use more dynamic market-based models, like wholesale spot market auctions, which have the potential to substantially improve flexibility and efficiency by more closely aligning resource procurement with real-time requirements. Another possibility may involve moving toward cost allocation based on the causer-pays principle. The Australian frequency control ancillary service market has made considerable progress in these directions.

Substantial benefits may also be achieved from more effective harnessing of demand response. Demand reductions in response to high prices are likely to occur when transmission systems are operating close to their security limits. Such responsiveness would help reduce pressure on system security and improve reliability by improving the balance between generation and load.

To date, efforts to harness demand responsiveness have typically relied on administrative approaches such as demand management or ad hoc public appeals. More effective market-based approaches need to be developed.

A variety of interruptible contracts with large industrial users are already used in North America, the United Kingdom, Scandinavia and Australia. However, considerable potential remains to be tapped.

Innovative financial products can support more effective harnessing of demand response. For instance, retail products could be developed that offer consumers differing degrees of service delivery. Such products would allow large customers to choose the level of service they are willing to pay for. They could also be used to identify consumers that are more willing to experience service interruptions. This could support more efficient targeting of certain emergency interventions, such as load shedding, to protect system security at least overall cost to the community.

Governments and key stakeholders need to consider how to promote the development of market-based demand response to support transmission system security. The Nordic and United Kingdom markets have made considerable progress in this direction.

However, there are limitations to the application of market-based approaches in this context. System security exhibits some characteristics consistent with a public good, and it is possible that a pure market solution may produce insufficient resources to maintain system security. The strength and depth of competition to provide services may also have implications for the deployment of market-based mechanisms.

Application of market-based mechanisms will also be affected by the quality and timeliness of information, and by market participants' ability to access information. Effective real-time metering, information management systems and control equipment are required. However, installation of these systems can be relatively expensive and coverage may therefore be limited to relatively few market participants. This could represent a practical barrier to rapidly deepening and broadening participation in the short-term, particularly in the context of demand response.

These and other practical, technical and institutional issues need to be carefully considered in the context of developing and deploying market-based mechanisms and products to help manage transmission system security. The combination of these issues may place some practical limitations on deploying market-based mechanisms at this time. Regulatory approaches will continue to be needed to ensure that transmission system security is not jeopardized. However, market-based mechanisms and products offer considerable potential to enhance and complement regulatory arrangements to strengthen transmission systems security at least cost.

INTRODUCTION

Modern economies are fundamentally dependent on reliable and secure electricity services. Electricity makes an essential contribution to economic performance, international competitiveness and community prosperity.

The growing importance of the information technology and communications sectors for economic activity and prosperity is serving to reinforce reliance on high quality electricity services. The Electric Power Research Institute (EPRI) has estimated the total cost of power disruptions to the information technology and communications industries in the United States at around $52 billion in 2003, and at around $100 billion for the economy as a whole or 1% of gross domestic product per annum[3].

Growing public sensitivity to supply disruptions reflects the increasing dependence of modern economies on reliable and efficient electricity supplies. Such sensitivity adds to the pressure on governments to effectively address these issues.

The substantial blackouts that struck North America and Europe during 2003 clearly demonstrated the fundamental importance of transmission networks to the efficient and secure operation of electricity markets and highlighted the vulnerability of electricity markets to transmission network failures. While large blackouts have happened in the past, these disruptions created considerable concern among policymakers, practitioners and the general public about transmission system security and its implications for the efficient and reliable operation of electricity markets.

In response, the IEA initiated a project to examine key issues affecting the reliability and performance of transmission networks serving competitive electricity markets. Project goals included to: identify and analyse the key issues affecting the development and performance of transmission networks in competitive electricity markets; promote understanding of these issues among policymakers and regulators; and facilitate debate and exchange of views between stakeholders about these issues and how best to address them.

Three workshops were held in 2004 exploring various aspects of these issues. The first workshop focused on transmission network reliability in competitive electricity markets. Key issues addressed included: lessons from the 2003 supply disruptions in North America and Europe; potential technological responses to improve system operation and reliability; regulatory

3. *EPRI (2003a).*

arrangements to strengthen transmission reliability in competitive markets; and regulatory and organisational options to improve transmission system operation.

The second workshop focused in more detail on the technological dimensions associated with improving the reliability and performance of electricity transmission and distribution. Key issues addressed included reviewing technological options to improve reliability and power quality; improving and expanding effective system control of integrated transmissions systems, and more effectively integrating distributed and intermittent generation technologies. Opportunities for improving research and development were identified and potential for greater international collaboration to promote development and appropriate deployment of technologies were discussed.

The third workshop focused on transmission network performance in competitive electricity markets. Key issues discussed included: the policy context for improving transmission performance in competitive electricity markets; the challenges and options to improve transmission reliability, planning processes and outcomes; encouraging timely and efficient network investment to improve transmission performance; regulation to reduce risk and strengthen transmission performance in competitive markets; and the potential for greater integration of transmission networks and competitive electricity markets to strengthen incentives for superior transmission performance.

Further information, including all presentations, background papers and summaries of outcomes are available on the IEA website (see http://www.iea.org/Textbase/work/workshopsearch.asp).

This publication focuses on transmission system security in competitive electricity markets. It draws primarily from the first and second workshops, and from official inquiries into major blackouts in Europe, North America and Australia in 2003 and 2004.

Chapter 1 provides a brief introduction to the nature and scope of transmission system security issues and considers the implications of electricity market reform for transmission reliability and system operation. Chapter 2 presents four case studies drawn from events in North America (August 2003), Sweden-Denmark (September 2003), Switzerland-Italy (September 2003), and Australia (August 2004) where transmission failures led to substantial supply disruptions.

Chpater 3 explores some key issues affecting transmission system security including: legal, regulatory and institutional arrangements; system operating standards and practices; communication and coordination (particularly in integrated networks spanning multiple jurisdictions and control areas); investment in technology and people; and asset management, especially maintenance of easements under transmissions lines. It also explores the potential for using market-based mechanisms to help improve transmission system security at least cost. Discussion endeavours to focus on issues from a policy perspective.

Other issues relating to the adequacy of transmission infrastructure to support efficient and reliable trade and competition (investment) and creating incentives for superior transmission network operation and development (regulation) are addressed in the IEA publication *Lessons from Liberalised Electricity Markets*, which examines key lessons for policy analysts from liberalisation in IEA member countries over the last decade.

CONCEPTS AND CONTEXT

Key Concepts

Blackouts focus attention on the reliability of electricity systems. Reliability is a very general term. At its simplest it can be defined as 'keeping the lights on'. However, this relatively simple definition is of only limited value in helping to better understand the multi-faceted nature of reliability within an electricity value chain. The concept of reliability needs to be 'unbundled' if it is to be better understood. For instance, the reliable provision and delivery of electricity services can be affected by a range of interrelated factors including:

- access to adequate and competitively-priced fuel supplies;
- adequacy of existing generation and transmission capacity to meet current and future demand;
- efficiency with which existing generation and transmission capacity is used to meet demand;
- effectiveness of generation and network investment signals and responses to meet current and future electricity demand;
- effectiveness of system operation;
- effectiveness of and conformance to reliability standards; and
- other public policy activities with implications for the security and reliability of electricity systems, such as subsidy assistance for investments in intermittent renewable generating technologies.

Reliability in this context encompasses the ability of the value chain to deliver electricity to all connected users within acceptable standards and in the amounts desired. Reliability possesses two key dimensions: adequacy and security[4].

Adequacy refers to the ability of the power system to supply the aggregate electric power and energy requirements of the customers within component ratings and voltage limits, taking into account planned and reasonably expected unplanned outages of system components.

Security, on the other hand, refers to the ability of a power system to withstand sudden disturbances such as electric short circuits or unanticipated

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4. The definitions of reliability, adequacy and system security presented draw on those developed by the North American Electric Reliability Council (NERC) and the International Council on Large Electric Systems (CIGRE).

losses of system components or unusual load conditions together with operating constraints. In this sense, security can be thought of as referring to the operational reliability of an existing power system. This security dimension can also have several facets. For instance, security can refer to the resilience of electricity systems to various forms of external threat, such as cyber or physical attack. It also incorporates the notion of system integrity, which refers to the preservation of interconnected system operation, or the avoidance of uncontrolled separation, in the presence of severe disturbances.

Discussions about the reliability of electricity systems tend to focus on issues affecting the capacity of electricity systems to generate and deliver sufficient electricity to meet demand under various conditions. Such discussions focus on the adequacy dimension of reliability. This publication will focus on the key policy issues associated with strengthening the operational reliability dimension of transmission system security in competitive electricity markets.

A Brief Outline of the System Security Challenge[5]

Maintaining reliable and secure transmission system operation is a challenging exercise that reflects the physical characteristics of electricity. In particular, electrical imbalances at any point within an interconnected transmission network can have immediate and severe repercussions for the quality and deliverability of electricity throughout the whole interconnected network. As a result, supply and demand must be balanced in real time across the whole interconnected network to ensure reliable supply that meets defined voltage and frequency requirements. The challenge is magnified by the dynamic nature of flows on interconnected transmission systems, which follow the path of least resistance determined by the constantly changing interaction between generation and load.

Maintaining secure and stable transmission systems is a complex and challenging balancing act. Key to success is the simultaneous balancing of electricity flows to maintain frequency and voltage subject to system stability limits and the thermal operating limits of the transmission infrastructure. Failure to do so can cause substantial damage to electricity infrastructure or lead to catastrophic failures and blackouts.

In an alternating current power system, frequency represents the rate at which the direction of current changes. A frequency cycle is completed every time current reverses direction and then returns to its original direction. Power system operators aim to maintain a constant frequency. In North America,

5. See Stoft, S. (2002) and US-Canada Power System Outage Task Force (2004a) for further discussion.

frequency is maintained at 60 cycles per second (Hertz - Hz), while in Europe frequency is typically maintained at 50 Hz.

Failure to balance supply and demand can cause variations in the frequency on an alternating current power network. When generation exceeds consumption power system frequency will increase, while insufficient generation to meet demand will result in falling frequency. Small deviations in frequency are common, reflecting changes in the aggregate balance between generation and load within an interconnected transmission system as individual generators modify output to meet constantly changing demand. However, large frequency deviations can cause severe damage to generating equipment. Protection systems on this equipment can in turn lead to disconnection of the equipment from the grid. This can worsen the frequency deviation, resulting in more equipment being disconnected, and this can start a cascade of disconnections that leads to a blackout. Conversely, extremely low frequencies can trigger load shedding to avoid system collapse.

Voltage can be thought of as representing the amount of electrical force or 'pressure' in a transmission system that causes current to flow in a circuit, measured in volts. Like frequency, power system operators aim to maintain voltage at a steady level. High voltage transmission systems tend to operate from around 220 kV, with the bulk transmission system typically operating from between 300 kV and 500 kV.

Changes in system conditions, such as increased real or reactive loads, high power transfers, or the loss of generation or transmission facilities can create an imbalance of reactive power supply and demand. This imbalance can lead to voltage instability or voltage collapse, which occurs when voltages progressively decline until stable operating voltages can no longer be maintained. Voltage instability can occur gradually within tens of seconds or minutes. Conversely, excessively high voltages may exceed the insulation capabilities of transmission lines, leading to dangerous electric arcs.

Power flows over transmission systems need to be managed within thermal and stability limits. Electrical losses resulting from power flows over transmission systems have the effect of heating transmission lines and other infrastructure used to transport electricity and can expose transmission infrastructure to overheating. Equipment heating rates are also affected by environmental factors such as ambient temperature and wind, and by the use of *reactive* power. Overheating will cause transmission lines to sag, possibly leading to short circuits resulting from electric arcs or direct contact with trees or other ground-based objects. Persistent overheating can also cause permanent damage to transmission infrastructure such as melting conductors on transmission lines. Thermal limits are imposed by system operators to set the maximum flow of *real* power on transmission lines to avoid overheating transmission equipment[6].

Stability limits are also used to establish maximum real power flows on transmission lines. In general, thermal limits tend to be the binding constraint on power flows over shorter distances, while stability limits tend to be the binding limits for longer distance power flows. Stability limits are often defined in terms of power flow and voltage.

Power flow (angle) stability limits are derived from the way power flows in an alternating current transmission system. Essentially, power flows from generation to load in an alternating current transmission line when the voltage at the load end of the line is out of phase with the voltage at the generator end. The greater this phase difference the greater the power flow. As loads take more power, more power flows down the transmission line which causes the phase difference between sending and receiving voltages to increase.

However, there is a limit to the amount of power that can flow down a transmission line. Voltage is sinusoidal, which means that when the voltages at either end of a transmission line get out of phase by half a cycle (180^o) or by a full cycle (360^o) they are identical and no power flows. This implies that the theoretical maximum power flow on an alternating current transmission line occurs when the phase differences between voltages at either end of the line reach 90^o. Transfers beyond this limit expose the system to voltage collapse. Lower limits of between 30^o and 45^o are typically applied, which correspond to a real power flow that sets the power flow stability limit for a transmission line.

Power stability limits are also set to avoid the risk of generation and loads within an integrated transmission system loosing synchronisation. Loss of synchronisation with the common system frequency means generators are operating out of step with each other. Loss of synchronisation can damage equipment and in extreme cases lead to the breakdown of an integrated transmission system into separate electrical islands.

6. *Power flows on alternating current power systems include both real power and reactive power.* Real *power refers to electricity that flows from generation to load to power electrical equipment. It is typically measured in kilowatts (kW) or megawatts (MW).* Reactive *power is that portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. It is typically measured in kilovars (kVAr) or megavars (MVAr). Reactive power consumption tends to depress transmission voltage, while its production (by generators) or injection (from storage devices such as capacitors) tends to support voltage. Reactive power can be transmitted only over relatively short distances during heavy load conditions. If reactive power cannot be supplied promptly and in sufficient quantity, voltages decay, and in extreme cases a 'voltage collapse' may result.*

Increasing power flows also tend to cause the voltage at the load end to decrease. Voltage reductions can be addressed by injecting reactive power, which maintains voltage levels as loads increase. However, there is a limit to this process. Once power flows reach a level that exhausts local reactive power reserves, any further flows will continue to reduce voltages. If voltage falls too low then it can begin to collapse uncontrollably. Voltage stability limits are established to avoid this risk.

Reliability Standards and Operating Practices

Experience indicates that effective real-time management of electricity systems can only be achieved through centralised, or centrally coordinated, system operation. System operation is generally undertaken by local transmission system owners, with a degree of coordination between them where integrated regional networks incorporate two or more transmission systems. Coordination has principally focused on the management of flows across interconnects immediately linking adjacent control areas.

System operators are also generally responsible for executing emergency procedures to manage extreme events in a manner that minimises the impact on supply while protecting critical electricity infrastructure.

Reliability Standards

Operational experience has led to the development of various reliability standards and practices to ensure that transmission systems are operated in a stable and secure manner. Given the nature of electricity and the potential for quick and catastrophic system-wide failure, these standards are designed to ensure that appropriate and sufficient resources are available to enable system operators to respond rapidly to manage extreme operating conditions or emergency events.

From an operational system security perspective, probably the most important of these reliability protocols is the N-1 standard. A power system can be described as being N-1 secure when it is capable of maintaining normal operations (ie. reliably delivering electricity of a given frequency and voltage subject to technical limits) in the event of a single contingency event, like the unplanned loss of a transmission line, generator or transformer. This standard has been adopted by system operators around the world to inform operational contingency planning, to guide management of system operation and to guide emergency efforts to return systems to a secure and stable operating condition within a reasonable time following a single contingency event, usually within 15 to 30 minutes.

This standard was adopted because all power systems are regularly affected by unpredictable faults and failures, such as lightning strikes or mechanical failure. Since such events are unavoidable, all power systems need to be able to endure them without unduly disrupting supplies. Blackouts can only be avoided in such circumstances where systems are operated with a sufficient security margin. This implies that there must be enough reserve capacity (either generation, demand response or imports) available to accommodate the loss of a generating unit and enough transmission capacity to accommodate changes in power flows resulting from the failure of a transmission line[7].

In principle, the N-1 standard is applied in a deterministic manner, which means that it is applied in the same way at all points within a system operator's control area irrespective of the probability or impact of a component failure. Application of this standard to achieve absolute levels of reliability would require a level of resource commitment that is neither practical nor cost-effective. In practice, the N-1 standard is typically applied in a manner that reflects operational resource constraints. As a result, the N-1 standard is typically applied to manage *credible* contingency events. Credible contingency events in this context typically exclude multiple independent failures within the period normally allowed to return a transmission system to a secure operating condition following an N-1 event. It is also applied in a manner that reflects system operator judgement and experience. For instance, multiple dependent failures are sometimes accommodated in particular cases where system operators consider the risk of their occurrence to be substantial. Probability risk assessment is sometimes used to help identify credible contingencies.

Operating Practices

Operating practices are designed to ensure that transmission systems are operated within the security bounds established by the N-1 standard. Typically, these practices are built around an iterative process that generally involves contingency assessment and planning, on-going monitoring of system operation and intervention as required to maintain system security.

Contingency assessment and planning is the first step and involves analysis and assessment of expected operating conditions based on anticipated power flows within and between system operator control areas. In competitive

7. *Krischen, D. and Strbac, G. (2004).*

electricity markets, operational contingency assessments are typically carried out for each trading interval or operating period, and in some cases for each dispatch interval. Initial assessments are generally carried out day-ahead, based on the expected availability of infrastructure and demand, including power flows associated with bilateral contracts. This initial assessment is then updated to account for proposed day-ahead spot market dispatch bids and offers, to the extent that they can be accommodated within the projected delivery capacity of the transmission system.

Contingency assessments are revised regularly in the period leading up to dispatch to incorporate new information that could significantly affect power flows, such as changes in the availability of generation or transmission lines and dispatch patterns resulting from intra-day trading or balancing market outcomes. This information is fed into a computer simulation of a transmission system to identify potential points of network congestion, and to determine the type, location and amount of technical reserves and other resources a system operator may require to prepare for credible N-1 contingencies.

Similar analysis is used to decide whether the merit-order dispatch determined on the basis of spot market trading may need to be modified to ensure secure system operation. The outcome of such analysis is referred to as security constrained dispatch and is often used to manage transmission system security in the event of persistent transmission network congestion.

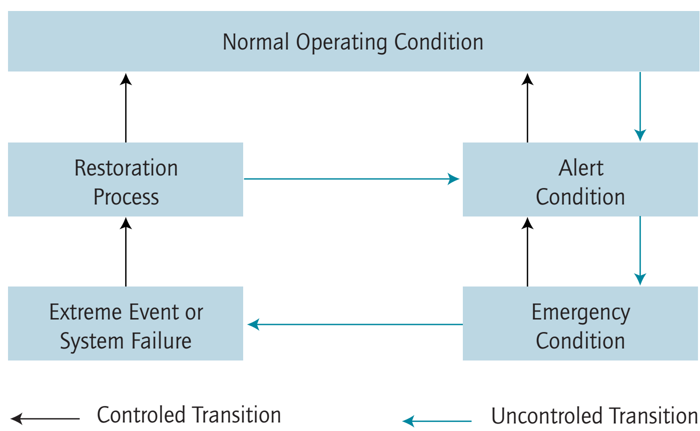
Reserve requirements may vary according to the nature and design of a transmission system. Radial transmission systems or other weakly integrated transmission systems, for instance, may be more exposed to the impact of transmission network failures, particularly the failure of interconnectors, which have the potential to immediately isolate portions of an otherwise integrated transmission system. In such circumstances, additional generation and network operating reserves may be required to address a higher risk of electrical islanding compared to a highly meshed transmission system where more transmission paths exist to carry displaced inter-regional power flows. This is a particular issue in integrated transmission systems with relatively weak interconnections, like the Australian National Electricity Market.

System operators monitor transmission systems during the operating period to ensure that secure operating conditions are maintained and so that they can respond in a timely and effective manner to emergency events. Operational management of transmission systems relies on real-time and near real-time information on power flows against technical limits at strategic points in transmission networks. Contingency assessment is typically updated throughout an operating period to accommodate actual operating conditions as they evolve. This practise is particularly important in the context of managing unpredictable changes in power flows resulting from real-time movements in load and unanticipated changes in the availability of generation and transmission network equipment.

When an emergency or N-1 contingency event occurs, system operators need to be able to intervene in a timely and effective manner to stabilise a transmission system and then return it to an N-1 secure state within the maximum period permitted by the reliability standards. Reliability rules usually allow system operators between 15 and 30 minutes to return a transmission network to an N-1 secure condition following an N-1 event. The typical control framework adopted by system operators to manage emergency conditions and N-1 events and return systems to a secure operating condition is summarised in Figure 1.

Figure 1

Dy Liacco System Security Model



Source: Dy Liacco, T. E. (1967).

A coordinated approach is required to ensure system security in transmission systems that span multiple system operator control areas, given the potential for cascading failures to rapidly spread and cause system-wide failures. Coordination and communication is critical for successful contingency assessment and planning, for effective system condition monitoring and for effective operator intervention to manage emergency events. Successful coordination in this context is built on effective information sharing. Information systems and protocols have been established to facilitate information exchange. Examples include the Day

Ahead Congestion Forecast in Continental Europe or the data provided through the Open Access Same Time Information System in North America. Information is typically shared on expected and actual power flows across interconnectors between neighbouring control areas and on the availability of generators and transmission lines. Coordination has been supported by specific institutional arrangements in some jurisdictions, such as the reliability coordinator framework that operates in North America under the auspices of the North American Electric Reliability Council and affiliated regional reliability councils.

Operating Tools

System operators have traditionally used a combination of methods to manage transmission system security including various forms of technical or operating reserves and services, redispatch and load shedding. The specific products, or ancillary services, available to help manage system security are usually defined in terms of their function and the time taken to deploy them. Key functions include frequency control, network control and provision for restoration of services following a blackout, usually referred to as black start services.

System operators would typically deploy operating reserves or employ redispatch before load shedding. Load shedding is usually treated as a last resort, in order to avoid catastrophic system failures. Products used to manage small routine imbalances and to react immediately to emergency events are deployed automatically in response to particular frequency or voltage triggers, while other services tend to be deployed manually by system operators as required.

However, these products provide system operators with only indirect control over power flows. In an alternating current transmission system, electricity flows according to the laws of physics along the path of least resistance. Hence, system operators must manage the mix of inputs – generation and load – to deliver frequency, voltage and power flows that are consistent with secure system operation.

System operators normally have access to a range of operating reserves including:

- **Frequency Control Regulation**. These reserves are used to manage small movements in frequency resulting from the constantly changing balance between generation and load on an integrated transmission network. They are automatically dispatched.
- **Frequency Control Contingency Reserves**. This is essentially the 'spinning' reserve, which is provided by power plants with turbines that are

spinning in synchronisation with the common system frequency but are not generating power. Such capacity can provide an immediate and significant injection of power if required. Spinning reserves can typically be ramped up to full production in less than 10 minutes.

- **Fast Response Active Reserves**. These are essentially 'non-spinning' reserves which can be deployed in a matter of minutes and be ramped up to full production within an hour. Spinning and non-spinning reserves are used to maintain services and to restore the balance between generation and load in the event of a sudden substantial generation or network outage.

- **Slow Response Active Reserves**. These reserves are typically employed in response to an unanticipated generation or network failure where sufficient advance notice is provided, or in response to a persistent emergency situation. Such reserves can usually be deployed within 4 to 8 hours.

- **Reactive Power Reserves**. These reserves provide reactive power to support voltage stability and power flows. Reactive power diminishes rapidly over relatively short transmission distances and must be provided locally. Reactive power can be provided by generators and by purpose-specific equipment such as capacitors.

System operators also procure black start services to facilitate system restoration following a blackout. These services are typically secured through bilateral contracts with generators, though system operators usually have some power to requisition necessary services in an emergency.

In principle, demand reductions could act as a substitute for generation reserve. Demand response therefore has the potential to provide many of these services. However, its contribution is likely to be limited to those services where there is relatively more time to respond.

Electricity Markets Help to Strengthen Transmission System Security

Access to reliable and affordable electricity is a key determinant of economic growth, international competitiveness and community prosperity. Recognising the important role of electricity in modern economies, many governments have pursued electricity market reform in an effort to improve efficiency and economic prosperity.

Reliable and effective performance of transmission networks will shape the operation and development of efficient wholesale electricity markets, particularly the emergence of effective regional markets that promote efficient price formation and trade. Potential economic advantages from effective electricity market reform include:

- efficient development of inter-regional trade which may increase effective competition and reduce the scope for market power abuse;
- improved capacity utilisation (both generation and networks) and deferral of expensive infrastructure investments; and
- greater transparency and more efficient price formation.

Substantial efficiency gains have resulted from electricity reforms undertaken in IEA countries. Benefits from electricity reform are more fully discussed in the IEA publication *Lessons from Liberalised Electricity Markets*.

More integrated and efficient electricity markets also have the potential to strengthen system reliability at least cost. Efficient interregional trade enables more effective sharing of reserve capacity, allowing system operators to draw on the reserves and resources of adjacent control areas to ensure reliable and secure system operation. In particular, it can improve management of frequency control and provide access to additional generating capacity to help stabilise the supply-demand balance during emergencies.

The potential benefits for reliability are enhanced where greater integration allows for more effective sharing of complementary generation technologies. For instance, greater integration of hydro-based power systems with thermal-based power systems can strengthen security of supply in the hydro-based system, especially during a drought. On the other hand, greater integration of a hydro-based system with a thermal-based system can improve the operational flexibility of the thermal system enabling more effective responses to real-time emergencies. The reliability benefits of such integration were clearly demonstrated during the 2002-03 winter in the largely hydro-based Nordic market, which was able to maintain uninterrupted supplies despite experiencing a 1 in 200 year drought.

Effective integration can also facilitate timely restoration following the loss of services by augmenting black-start responses. In some cases it may help to supplement local generation to provide voltage support. In short, greater integration afforded by electricity market reform helps to strengthen the resilience of power systems, which can improve overall system reliability.

Electricity markets also provide greater transparency, which can help to strengthen accountability mechanisms designed to ensure that unbundled electricity sectors make adequate provision for system security. They can also create powerful incentives for more efficient use of transmission systems, consistent with effective management of system operation. Efficient markets also have the potential to help value transmission system security, particularly where greater demand responsiveness can be harnessed.

Electricity Markets are Changing the Way Transmission Systems are Used

Electricity market reform has brought unbundling and independent, decentralised decision-making. As a result, decisions relating to network use and investments affecting network operation and performance that were once made in a centrally coordinated way within vertically integrated utilities are made by a number of independent market participants.

Decentralised decision-making has fundamentally changed utilisation of transmission networks. Previously stable and relatively predictable patterns of network use have in many cases been replaced with less predictable usage, greater volatility of flows and greater use of long-distance transportation, reflecting growing inter-regional trade. No existing major transmission systems have been designed for such use. Table 1 summarises several key factors affecting the changing pattern of transmission system use, which have implications for managing transmission system security.

A particular feature of reformed electricity markets is the growth in inter-regional electricity transmission. Figure 2 illustrates the substantial growth in inter-regional electricity transfers within the Nordic market, where interregional trade has risen from around 10.4% of total Nordic load in 1997 to around 16.0% of total load in 2004, an increase of over 50%.

Table 1

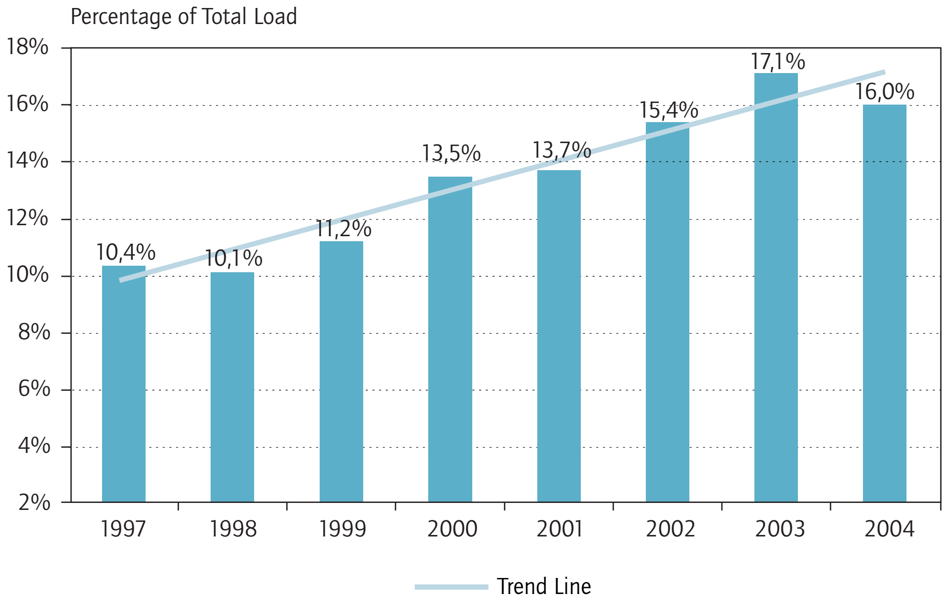
Emerging Conditions Affecting Transmission System Reliability

Pre-reform Conditions	Post-reform Emerging Conditions
Fewer, relatively large resources	Smaller, more numerous resources
Long-term, firm contracts	Contracts shorter in duration More non-firm transactions, fewer long-term firm transactions
Bulk power transactions relatively stable and predictable	Bulk power transactions relatively variable and less predictable
Assessment of system reliability made from stable base (narrower, more predictable range of potential operating states)	Assessment of system reliability made from variable base (wider, less predictable range of potential operating states)
Limited and knowledgable set of utility players	More players making more transactions, some with less interconnected operation experience; increasing with retail access
Unused transmission capacity and high security margins	High transmission utilization and operation closer to security limits
Limited competition, little incentive for reducing reliability investments	Utilities less willing to make investments in transmission reliability that do not increase revenues
Market rules and reliability rules developed together	Market rules undergoing transition, reliability rules developed separately
Limited wheeling	More system throughput

Source: United States-Canada Power System Outage Task Force.

Figure 2

Growth in Inter-regional Power Exchanges in the Nordic Electricity Market: 1997 to 2004



Source: Nordel Annual Reports 1997-2004.

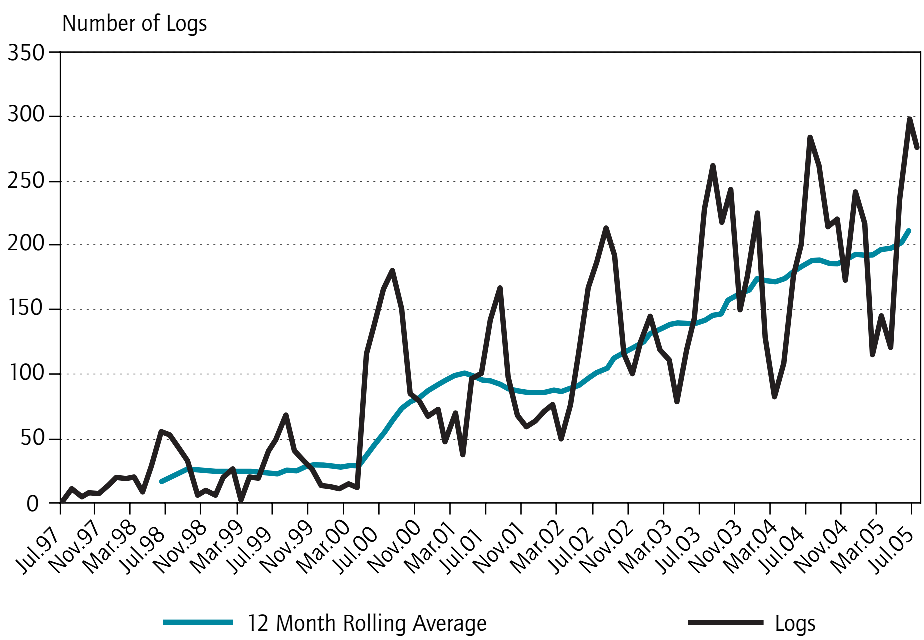
Inter-regional trade is increasingly driven by the relative cost of electricity across interconnected regions. In general, merit-order dispatch will create electricity flows from generation in low priced regions to load in high priced regions until prices are equalised or congestion on transmission lines prevents transfers. Patterns of network usage tend to reflect regional rather than local supply and demand, resulting in patterns of use that can create transmission congestion even during off-peak times.

Transmission systems are being run more efficiently, which means that they are also being run closer to their security limits for longer periods than generally seen before reform. Recent system adequacy assessments conducted in North America by the North American Electric Reliability Council (NERC) and in Continental Europe by the Union for the Coordination of Transmission of Electricity (UCTE) have noted a reduction of spare capacity margins on bulk transmission systems. With inter-regional trade expected to continue to grow at a greater rate than transmission capacity expansion, the prognosis is for margins to continue to tighten. This implies that less spare capacity will be available to support transmission system security in future, with transmission systems facing growing congestion and longer periods of operation at or near their security limits.

These trends are reflected in transmission loading relief (TLR) data for the North American Eastern Interconnection, presented in Figure 3. TLRs provide an administrative mechanism for managing potential transmission system security violations on key elements of the bulk transmission system, such as flows that might overload transmission lines or threaten stability limits. Reliability coordinators can use TLRs to reduce such power flows. Requests are normally activated within 30 to 60 minutes of being received. Figure 3 shows a substantial growth in the total number of monthly TLRs between July 1997 and July 2005, consistent with growing congestion and running the transmission system closer to its security limits to accommodate increasing levels of inter-regional trade.

Figure 3

Monthly Transmission Loading Relief Requests: 1997 to 2005



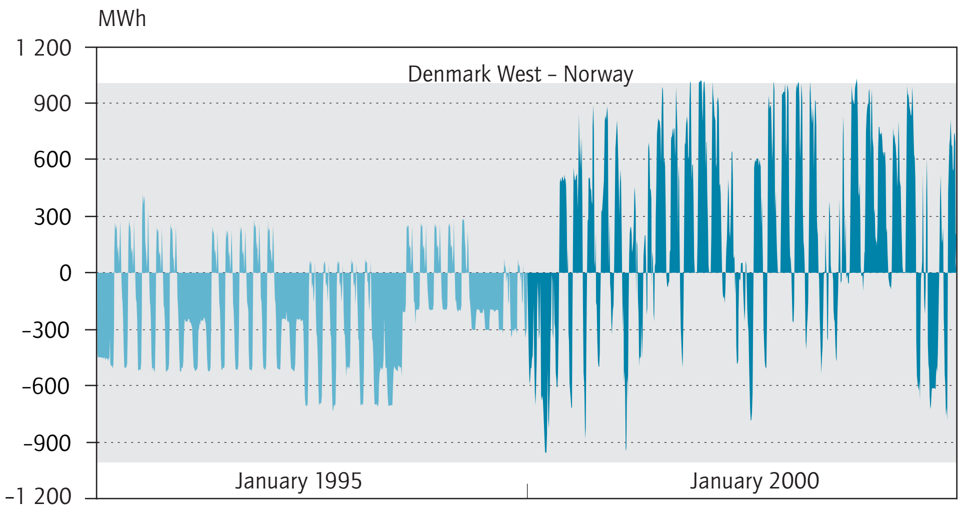
Source: North American Electric Reliability Council.

More volatile and less predictable power flows have also emerged with electricity market reform. Greater volatility reflects, in part, the increasing proportion of flows that are being determined by independent agents responding to differences in inter-regional prices, which in turn drives flows across integrated networks. These trends are facilitated by transparent wholesale markets that reveal regional price variations and facilitate efficient and timely inter-regional responses based on merit-order dispatch of generation.

These trends are revealed in Figure 4, which compares power flows across the interconnection between Norway and West Denmark before and after the introduction of electricity reform in Denmark. This comparison suggests an increase in the magnitude and volatility of inter-regional power flows following the introduction of electricity reform.

Figure 4

Power Flows between West Denmark and Norway: 1995 and 2000



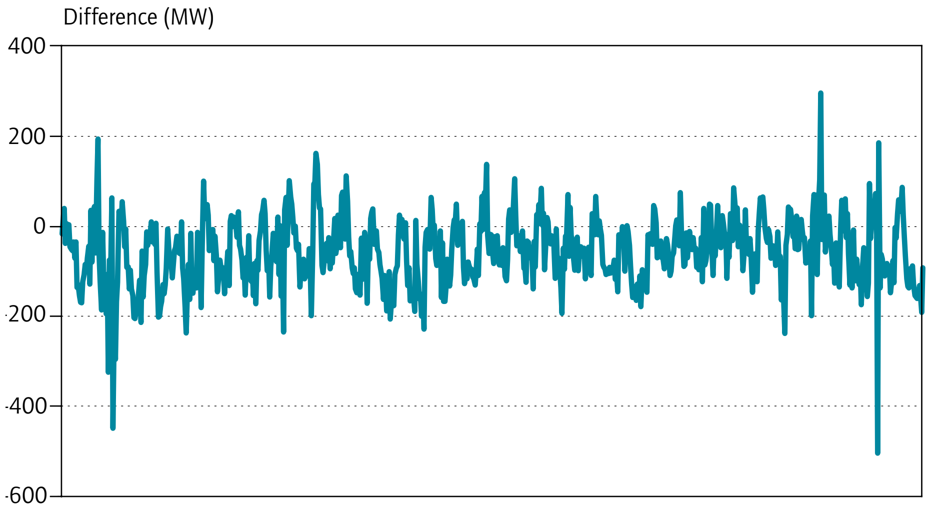
Source: Energinet.dk.

Volatility of power flows is also reflected in Figure 5, which charts the difference between day-ahead scheduled hourly power flows and actual hourly power flows on interconnections with the region controlled by the New England Independent System Operator for August 2005. In this example, the discrepancies recorded between day-ahead scheduled and actual power flows were regularly quite large, with 419 hours during August 2005, or 56% of total hours, recording discrepancies of over 10%, and 84 hours, or 11% of total hours, recording differences of over 50%. Such considerable differences between day-ahead and actual power flows indicate that inter-regional power flows in competitive electricity markets can exhibit considerable real-time volatility, creating a very dynamic system operating environment with less predictable power flows.

Large-scale introduction of less greenhouse gas intensive forms of intermittent generation, such as wind power, have the potential to further promote volatility and reduce predictability of transmission flows. Intermittent

Figure 5

Difference between Day-ahead Scheduled and Actual Metered Power Flows on all Interconnectors to the New England Independent System Operator Region: August 2005



Source: New England Independent System Operator.

generation has the potential to drive unscheduled power flows which can create challenges for maintaining transmission system security in real time. It may also create reverse power flows from a distribution system to the transmission system, which can make managing transmission system security considerably more complex in regions with a considerable volume of intermittent generation[8].

However, the implications of intermittent generation for transmission system security are likely to depend on the volume of such generation and the nature of the wholesale market design. The implications are likely to be relatively low where intermittent generation represents a relatively small proportion of total generation or where considerable excess transmission capacity exists. Similarly, spot markets that permit trade closer to real-time dispatch may have the potential to respond in a more timely and efficient way to manage any imbalances resulting from forecasting errors regarding the availability of intermittent generation than day-ahead markets.

More extensive integration of intermittent generation into market dispatch, including exposure to related balancing costs, may strengthen incentives for

8. *Elkraft System (2004a).*

intermittent generators to more effectively manage their output, which could improve the predictability and manageability of these flows from a transmission system security perspective. Scope may also exist to extend the application of technical generator standards to strengthen the contribution intermittent generators can make to supporting transmission system stability[9].

More Dynamic Operating Conditions Magnify Challenges for Managing Transmission System Security

Electricity market reform is changing the way transmission systems are used. Greater regional market integration and inter-regional trade are leading to longer distance, less predictable and more volatile electricity flows. These trends are combining to reduce 'spare' transmission capacity while also creating a more dynamic system operating environment. Together, they create new challenges for managing and maintaining transmission system security, with the focus shifting more toward real-time monitoring and management.

Greater amounts of reactive power are required to provide the voltage support needed to sustain increasing inter-regional power flows. Reactive power is a locally provided resource. Increasing transmission system use has the potential to rapidly exhaust reactive power resources, placing systems at or near their voltage stability security limits and increasing their exposure to voltage-related instability phenomena[10].

However, probably the most significant emerging challenge from a transmission system security management perspective is the growth of unscheduled parallel power flows associated with increasing inter-regional electricity exchanges. Parallel power flows, also referred to as loop flows, reflect the physics of alternating current transmission systems, where electricity flows uncontrollably along the path of least resistance from generation to load. In highly meshed transmission systems serving competitive electricity markets, the physics of power flows can combine with the constantly changing mix of generation and load to create significant and complex unscheduled power flows. Such flows have the potential to substantially weaken transmission system security if they are not fully taken into account by system operators.

Figure 6 provides an example of how a power flow from a utility in Wisconsin to the Tennessee Valley Authority would travel across transmission lines in the Eastern Interconnection. A colour contour shows the percentage of the

9. UCTE (2005b).
10. UCTE (2004a).

Figure 6

Parallel Power Flows on a Transfer from Wisconsin to Tennessee

Source: Hauer, J. et al. *(2002)*

transfer that would flow on lines carrying at least 2% of the flow. The figure indicates that a single transfer can simultaneously affect flows on many transmission lines in several control areas.

Figure 7 provides a similar example tracing the path of power flows associated with a 1000 MW transfer between northern France and Italy. In this example a little over one-third (38%) of power would flow directly from France to Italy, while nearly two-thirds (62%) would flow along different parallel routes, including around 15% flowing through Belgium and the Netherlands.

Managing transmission system security in an environment of significant parallel flows is a daunting challenge. Independent decentralised decision-making can impose thousands of simultaneous transactions on an integrated transmission system, leading to mutual interference and congestion. Mitigating such congestion can be a technically difficult task, particularly in real time. Effective responses require holistic, real-time information on power flows across an integrated transmission system; information which is not always available to local system operators and hence not always fully reflected in contingency planning and assessment, or in system operating dispatch decisions.

The transmission system security challenge is magnified where transmission paths cross multiple control areas. An effective, coordinated response is required to successfully manage transmission system security in these circumstances. To succeed, system operators need effective real-time management procedures, operating experience, holistic modelling for operational contingency assessment and planning purposes and integrated data resources.

Present systems and operating practices may not be sufficient to meet the challenge and may leave system operators unaware of the full extent of parallel flows, increasing the risk of flows not being appropriately considered in the context of operational contingency assessment and planning. Such failures would have the potential to significantly degrade system operator real-time situational awareness and management, with the potential to jeopardise transmission system security[11]. Parallel flow effects have been identified as a contributing factor in both the US-Canadian and Swiss-Italian blackouts of 2003[12]. These events are further discussed among the case studies presented in Chapter 2.

Parallel flows make predicting power flows following an N-1 contingency event more difficult, magnifying the challenge of managing emergency situations. Good situational awareness and effective coordination are required to ensure

11. *Hauer, J.* et al. *(2002).*

12. *See US-Canada Power System Outage Task Force (2004a); the various investigations into the Swiss-Italian event; Bialek (2004).*

Figure 7

Parallel Flows Associated With a 1 000 MW Transfer from France to Italy

Source: Haubrich, H-J. and Fritz, W. (1999)

an appropriate response to manage emergency events, particularly within integrated transmission systems spanning multiple control areas. In the emerging more dynamic operating environment, real-time security monitoring and automatic information exchange between system operators is required to effectively manage and coordinate emergency responses.

At the same time, unbundling has also reduced transmission system operators' capacity to manage system balancing through coordinated actions across the value chain, while also magnifying their exposure to systemic risk[13]. The emergence of regional markets that span multiple control areas has added to the transmission system security challenge by increasing each system operator's exposure to the operational decisions of other system operators and to potential failures outside their control area. Increased exposure to systemic risk may have implications for the frequency and nature of extreme or emergency events, and how best to manage them.

In this more integrated and dynamic operating environment, an event affecting a relatively distant part of an integrated transmission network may have greater potential to interrupt the delivery of electricity throughout an interconnected network and severely disrupt the supply and operation of electricity markets.

A More Dynamic Operating Environment May Also Affect the Nature and Frequency of Outages

Large blackouts are by no means a new phenomenon. Though relatively rare, they are never completely avoidable. Major blackouts have been the catalyst for significant reforms to strengthen transmission system security in the past. Table 2 documents some of the major transmission-related outages recorded in North America between 1965 and 2002.

In general, small service disruptions are relatively common events in most power systems, with large events remaining relatively rare. Weather-related events are the most common cause of outages on transmission systems.

However, analysis of North American outage data by the Electric Power Research Institute (EPRI)[14] suggests that the frequency of larger disturbances may be increasing. Between 1991 and 1995, 41 events were recorded that affected over 50 000 consumers, with over 355 000 consumers affected on

13. Systemic risk in this context refers to the impact of a failure in one part of the value chain on the operational performance of other parts of the value chain.

14. EPRI (2003a).

Table 2

Some Major North American Blackouts: 1965 to 2002

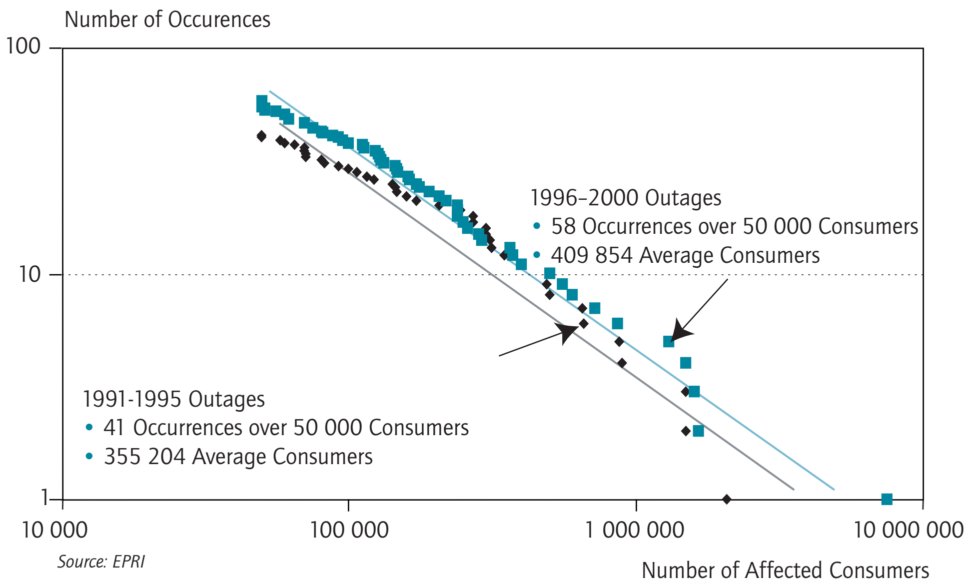
Event	Date	Area Affected	Customers Disconnected	Load Lost (MW)	Duration
Great North-eastern Blackout	November 1965	New York, Connecticut, Massachusetts, Rhode Island, parts of Pennsylvania, northeastern New Jersey (USA); and parts of Ontario (Canada)	30 Million	20,000	13 hours
New York City Blackout	July 1977	New York City	9 Million	6,000	26 hours
West Coast Blackout	December 1982	Pacific North West	Over 5 Million	12,350	N.A.
West Coast Blackout	July 1996	Arizona, California, Colorado, Idaho, Montana, Nebraska, Nevada, New Mexico, Oregon, South Dakota, Texas, Utah, Washington, and Wyoming (USA); Alberta and British Colombia (Canada); and Baja California (Mexico)	2 Million	11,850	A few minutes to several hours.
West Coast Blackout	August 1996	Arizona, California, Colorado, Idaho, Montana, Nebraska, Nevada, New Mexico, Oregon, South Dakota, Texas, Utah, Washington, and Wyoming (USA); Alberta and British Colombia (Canada); and Baja California (Mexico)	7.5 Million	Over 28,000	A few minutes to 9 hours
Upper Midwest Blackout	June 1998	Minnesota, Montana, North Dakota, South Dakota and Wisconsin (USA); Ontario, Manitoba and Saskatchewan (Canada)	152,000	950	Up to 19 hours

Source: US-Canada Power System Outage Task Force.

average by these events. By comparison, between 1996 and 2000, 58 events affecting over 50 000 consumers were recorded, with nearly 410 000 consumers affected on average. The total number of events affecting more than 50 000 consumers rose by around 41% during the second half of the 90's compared to the first half, while around 15% more consumers were effected by these disturbances, on average, between 1996-2000 compared to the period 1991-95. Figure 8 provides a frequency distribution of these events.

Figure 8

Frequency Distribution of North American Outages Affecting More than 50 000 Consumers: 1991-95 and 1996-2000

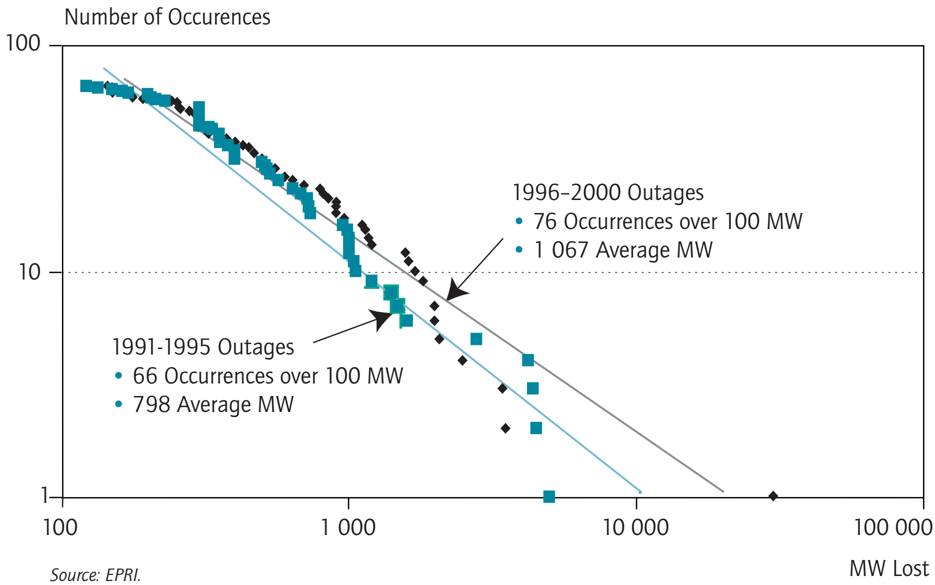


Source: EPRI

EPRI's analysis of this data by quantity of load lost reveals similar trends. Between 1991 and 1995, 66 events occurred that resulted in the disconnection of over 100 MW of load, with an average loss of 798 MW per event. By comparison, between 1996 and 2000, 76 similar events were recorded with an average loss of 1,067 MW per event. The total number of events during the second half of the 90's exceeded those recorded during the first half of the 90's by around 15%, while the average loss for the period 1996-2000 exceeded the 1991-95 period by around 34%. Figure 9 provides a frequency distribution of these events.

Figure 9

Frequency Distribution of North American Outages Affecting More than 100 MW: 1991-95 and 1996-2000



Source: EPRI.

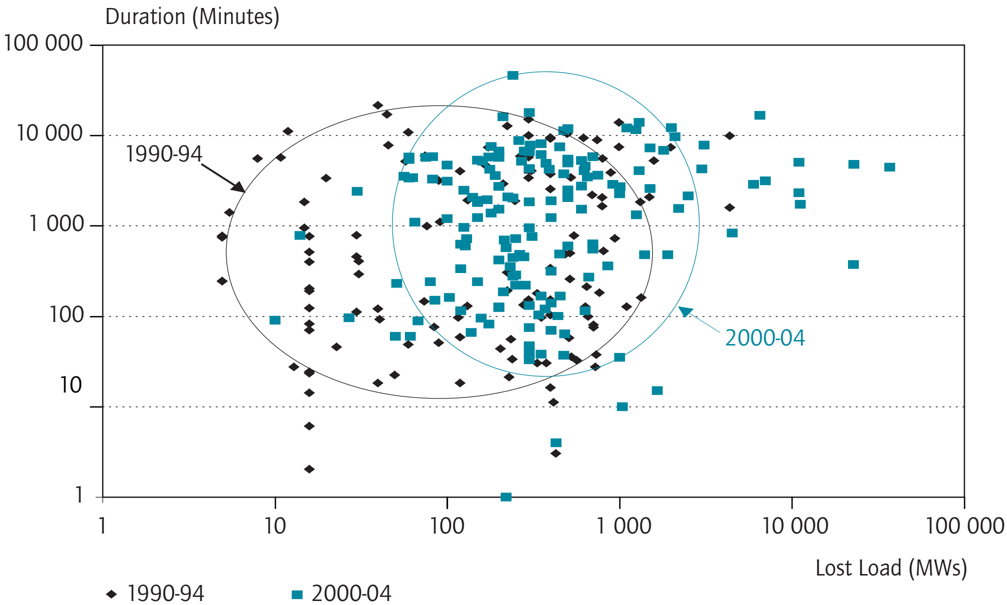
International Energy Agency analysis of a sample of North American outage data by load lost and duration of outage suggests similar trends. This analysis compares a sample of events that occurred between 1990 and 1994 with a sample of more recent outages that were recorded between 2000 and 2004. The results, presented in Figure 10, may suggest a trend toward larger outages with slightly longer durations.

This might be partially explained by growing integration of regional electricity markets and increasing inter-regional electricity flows over the period, which may have helped to spread the impact of disturbances. It may also reflect efforts to mitigate small disruptions, which have the potential to increase the frequency of larger outages due to the complex dynamic relationship between smaller and larger disturbances[15]. However, care should be exercised in drawing conclusions from this data. Many factors have influenced and possibly biased these results. A more thorough examination of the data to identify and remove any biases would be necessary before drawing more definitive conclusions.

15. For further discussion of this phenomenon see Carreras, B. et al. *(2003).*

Figure 10

Selected North American Outages: 1990-94 and 2000-04



Source: United States Department of Energy Disturbances Database.

Analysis of previous large-scale outages indicates that most occur when transmission systems are operating at or close to their security limits[16]. When transmission systems are operating at their security limits, an N-1 event immediately creates an unstable operating environment and increases a system's exposure to multiple dependent contingencies. Multiple dependent contingencies can be characterised as internal failures that occur as a direct result of an earlier N-1 event. Examples include overloads that trip transmission lines and other equipment, inappropriate operation of protection devices that unexpectedly trip equipment, or system operator error. Such dependent events have the potential to rapidly transform a credible N-1 contingency event into a cascading system failure culminating in a large-scale blackout.

Electricity reform has led to more efficient use of transmission systems, and greater regional integration of power flows resulting from inter-regional trade. As a result, transmission systems are being run closer to their security limits for longer periods than in the past. Although this does not directly affect a

16. *Analysis of previous large-scale events is provided in Knight, U. G. (2001).*

system operator's ability to operate a transmission system in an N-1 secure state (given that providing adequate operating reserves to manage credible N-1 events always takes precedence over other uses of transmission resources), it does increase exposure to the multiple dependent contingency phenomenon. Greater integration resulting in longer distance power flows also has the potential to enable disturbances to spread more rapidly through a transmission system, leading to larger-scale blackouts[17].

Increasing complexity and volatility of power flows is creating a more dynamic real-time operating environment that increases the challenges associated with managing transmission system security, particularly during emergency events. It also has the potential to increase the risk of operator error in response to emergency events, which can result in multiple dependent contingencies and cascading system failures. These risks are likely to be magnified in integrated transmission systems spanning multiple control areas.

Reliability Standards and Operating Practises Must Change to Meet the New Challenges

Electricity market reform is substantially changing the operating environment for maintaining transmission system security. Inter-regional trade is creating longer distance power exchanges, while independent decentralised decision-making is leading to less predictable power flows. Growing demand for transmission capacity to accommodate inter-regional trade means that transmission systems are increasingly being run at or near their security limits. These fundamental changes are creating a far more complex and dynamic operating environment from a transmission system security perspective.

Despite these fundamental changes, development of regulatory arrangements, reliability standards and system operating practices relating to transmission system security generally have not kept pace with the new real-time system operating challenges resulting from electricity market reform. The major blackouts of 2003 and 2004 raised fundamental questions about the appropriateness of these standards and practices in this new operating environment. Examination of operating standards and practices is being undertaken in North America and in Europe in the wake of these disturbances. But the focus has been on technical matters. Failures of the kind experienced in 2003 and 2004 also raise strategic issues for policymakers.

17. *See Hauer, J.* et al. *(2002) and Carreras, B.* et al. *(2003) for further discussion of the multiple dependent contingency and cascading failures phenomena.*

The time has come for policymakers to engage in this debate to ensure the development of integrated and comprehensive responses that will enhance transmission system security in competitive electricity markets.

TRANSMISSION SYSTEM SECURITY CASE STUDIES

Introduction

Several substantial supply disruptions involving a failure of network services occurred in North America, Europe and Australia during 2003 and 2004. Four of these events are featured in the following case studies:

- the 14 August 2003 event affecting the north-eastern United States and south-eastern Canada;
- the 28 September 2003 event affecting southern Switzerland and Italy;
- the 23 September 2003 event affecting southern Sweden and eastern Denmark; and
- the 13 August 2004 event affecting the National Electricity Market in eastern Australia.

These events clearly demonstrate the fundamental importance of reliable network services for the efficient and secure operation of electricity markets and at the same time highlight the vulnerability of electricity markets to network failures. They provide a valuable practical context for identifying and understanding the key issues for policymakers.

CASE STUDY 1: The North-eastern United States and South-eastern Canada

The largest supply disruption in North American history struck at around 4.13 p.m. on 14 August 2003. It affected eight states in the Midwest and the Northeast of the United States and the Canadian province of Ontario.

This event had two distinct phases. It began with a combination of failures and system operator inaction in Ohio between 12.15 pm and 4.06 pm, which led to the progressive tripping of key 345 kV lines in the Cleveland-Akron area and in northern Ohio. The failure of the Sammis-Star 345 kV line in Ohio at 4.06 pm triggered the regional cascade phase of the event: a seven minute period during which generator and transmission line trips spread from the Cleveland-Akron area in Ohio across most of the Northeast of the United

States and Ontario. The following event summary is drawn from the final report of the US-Canada Power System Outage Task Force (the Task Force)[18].

A timeline identifying the sequence of key events in the Ohio phase of the blackout is presented in Figure 11.

The Ohio phase started at 12.15 pm when erroneous input data rendered the Midwest Independent System Operator's (MISO's) state estimator[19] ineffective. The state estimator and real time contingency analysis tools were effectively out of service between 12.15 pm and 4.06 pm. Without an effective state estimator and with its normal automatic operation disabled until 2.40 pm, MISO could not perform effective contingency analysis within its reliability area, preventing timely 'early warning' assessments of system status and reliability.

At 1.31 pm, First Energy's (FE) Eastlake 5 generation unit tripped and shut down automatically. Eastlake 5 is a major provider of active and reactive power within the FE service area and its loss combined with the unavailability of other substantial local generators significantly increased the potential for transmission line overloads. Following the loss of Eastlake 5, FE's operators did not perform a contingency analysis to determine whether the loss of further transmission lines or generating capacity would put its system at risk. Subsequent analysis by the Task Force indicated that the loss of Eastlake 5 was a critical step in the sequence of events.

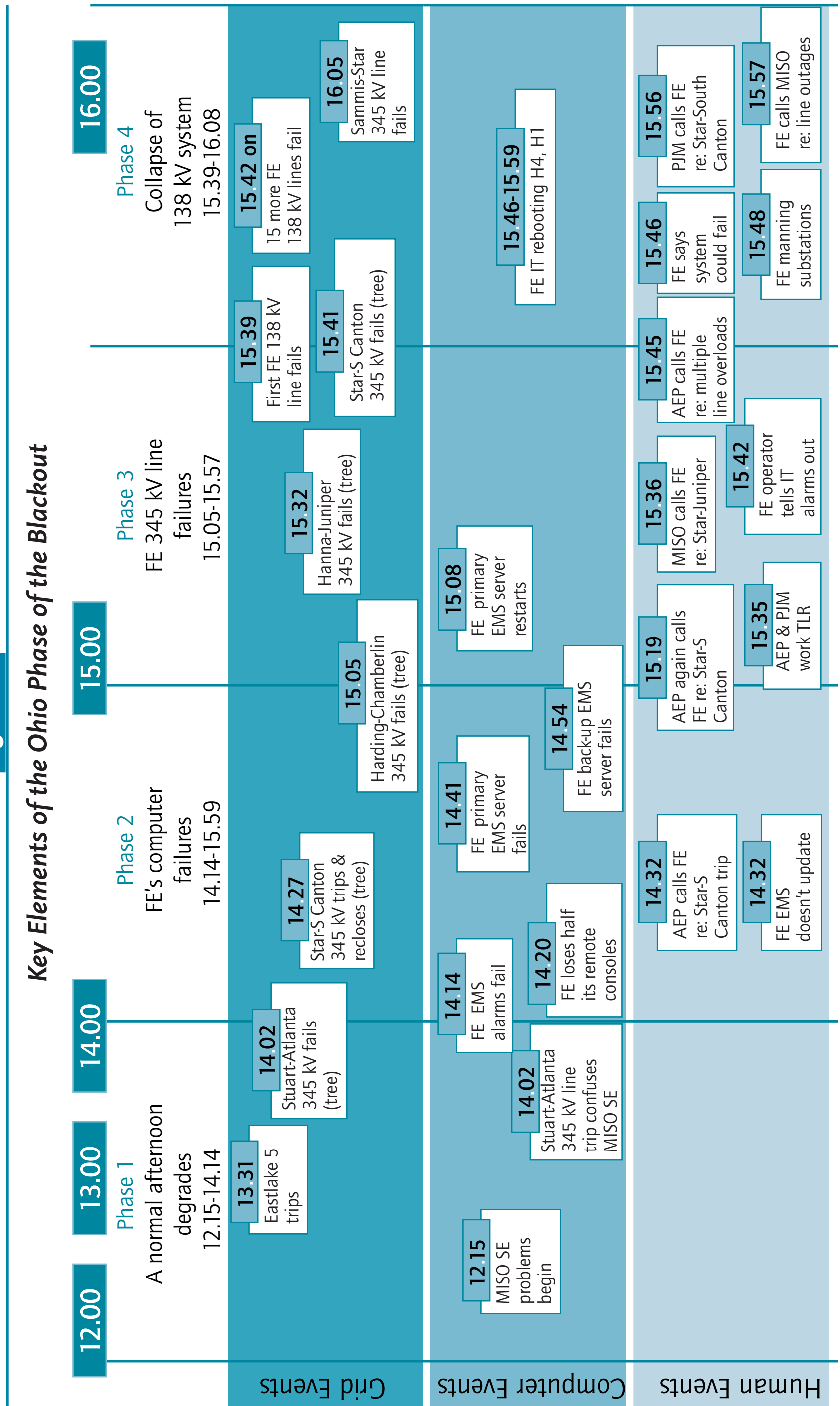
It is virtually impossible to manually monitor all events and power system conditions simultaneously. Hence, system operators rely heavily on automatic alarms to provide early warning of events and changing system operating conditions that need to be addressed. Starting around 2.14 pm, FE's control room lost some of its key system monitoring equipment. First to fail were the audible and on-screen alarm systems and alarm logs. FE's system operators were unaware of the failure, worsening their capacity to respond to a rapidly degrading situation. FE's alarm system was not restored until after the blackout.

18. *See US-Canada Power System Outage Task Force (2004a). Chapter 5 details the Ohio phase while Chapter 6 details the regional cascade phase of the event.*

19. *A state estimator is a computer program that models the transmission system. It is used to confirm that the monitored electric power system is operating in a secure state by simulating the system both at the present time and one step ahead, for a particular network topology and loading condition. With the use of a state estimator and its associated contingency analysis software, system operators can review each critical contingency to determine whether each possible future state is within reliability limits.*

Figure 11

Key Elements of the Ohio Phase of the Blackout



Source: US-Canada Power Outage Task Force (2004a).

Shortly thereafter, several remote terminals that relay real-time SCADA data[20] to the energy management system (EMS)[21] failed, further degrading system operators' capacity to monitor system performance.

Finally, the primary server hosting the EMS's alarm applications failed, and the back-up system failed shortly thereafter. The combination of these failures disabled Automatic Generation Control between 2.54 pm and 3.08 pm and again between 3.46 pm and 3.59 pm. It also slowed other EMS functions. FE system operators failed to detect the tripping of facilities essential to maintaining system security in their control area. Unaware of the loss of alarms and a limited EMS, they made no alternative arrangements to monitor the system.

FE system operators received information suggesting emerging system security problems from several other sources throughout the afternoon including MISO (FE's reliability co-ordinator), American Electric Power (AEP - a neighboring system operator), PJM (a neighboring reliability coordinator that includes Pennsylvania and other states), FE field personnel and customers. However, FE system operators dismissed this information as either not accurate or not relevant to managing their system. There was no subsequent verification of conditions with MISO and FE did not inform MISO or adjacent system operators when they became aware that system conditions had changed due to unscheduled equipment outages that might affect other control areas.

Between 3.05 pm and 3.41 pm, three 345 kV transmission lines into the Cleveland-Akron area tripped due to contacts with overgrown trees. First to trip was the Harding-Chamberlain line at 3.05 pm. This was a significant event which combined with the earlier loss of the Eastlake 5 generation unit, pushed the FE system beyond its N-1 secure operational limits. However, FE system operators were not aware of the failure and took no action to return the system to a reliable and secure condition. MISO's EMS did not monitor the Harding-Chamberlain line and was therefore unaware of its failure or that its failure would represent a significant contingency event under the circumstances.

Loss of this transmission path caused the remaining three southern 345 kV transmission lines into Cleveland to pick up more load and caused more power to flow through the underlying 138 kV network. Two of these remaining 345 kV lines also tripped after coming into contact with trees, leaving only

20. *The supervisory control and data acquisition (SCADA) system is a system of remote control and telemetry used to monitor and control the electric system.*

21. *An energy management system (EMS) is a computer control system used by electric utility dispatchers to monitor the real time performance of various elements of an electric system and to control generation and transmission facilities.*

the Sammis-Star 345 kV transmission line operational. These trips increased loads on the remaining 345 kV and 138 kV network, degrading voltages on the FE system and making it increasingly insecure.

From 3.40 pm FE, MISO and neighbouring utilities had begun to realise that the FE system was in jeopardy. PJM and AEP had already begun organising 350 MW of Transmission Loading Relief[22] from 3:35 pm to reduce overloading on the Star-South Canton 345 kV line (a line spanning AEP and FE control areas and jointly managed). However, Task Force analysis indicates that this action or other redispatch would not have averted the overload. Task Force analysis suggests that by this time, the only way overloading in Ohio and the subsequent regional cascading could have been averted would have been for FE to initiate at least 1 500 MW of load-shedding in the Cleveland-Akron area. No load-shedding was undertaken by FE system operators.

Each 345 kV line failure placed greater stress on FE's 138 kV network serving the Cleveland-Akron area, overloading lines and reducing voltage. Twelve 138 kV lines tripped between 3.39 pm and 3.59 pm. A further four 138 kV lines and the Sammis-Star 345 kV line tripped between 4.00 pm and 4.08 pm. Declining voltage resulting from these line failures tripped several large industrial users with voltage-sensitive equipment, leading to the disconnection of around 600 MW of load in the Akron area.

Failure of the Sammis-Star line at 4.06 pm triggered the uncontrollable regional cascade. At this point it was no longer possible for FE to manage the event with load shedding or any combination of redispatch. Although Sammis-Star was heavily overloaded at the time, the line was tripped by its protective relays which treated the high power flows as a short circuit. Failure of the Sammis-Star line shut down the 345 kV path into northern Ohio from eastern Ohio.

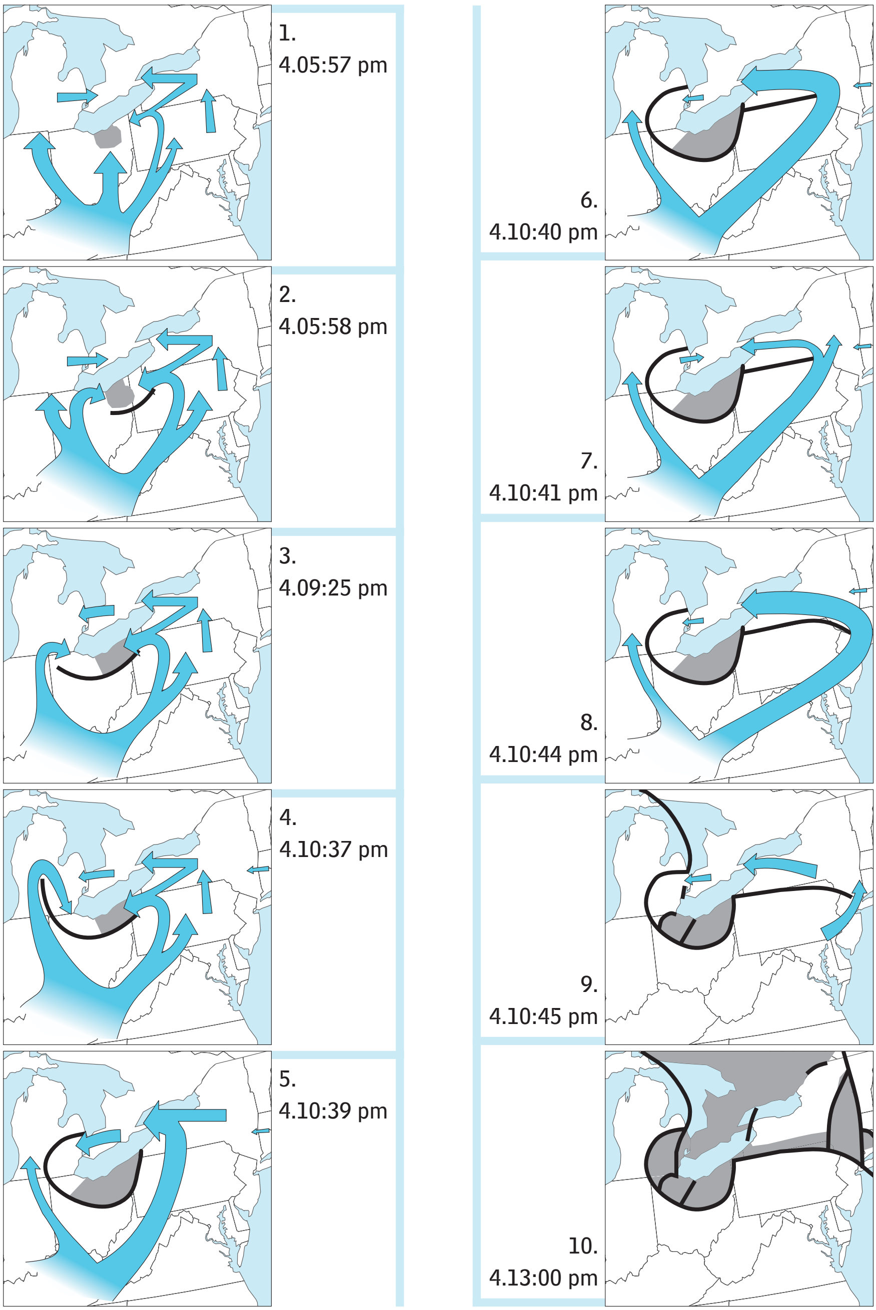
This failure combined with high demand in northern Ohio instantly created substantial, unstable flows as power sought new paths into northern Ohio, overloading lines in adjacent areas. The cascade spread rapidly as lines and generating units were automatically tripped by protective relays to avoid physical damage. Figure 12 summarises the regional cascade phase of the event.

Shortly before the collapse, large (but normal) electricity flows were moving across FE's system from generators in the south (Tennessee and Kentucky) and

22. *Transmission Loading Relief (TLR) is an administrative procedure used to manage system security violations on key elements of the bulk transmission system, such as flows that might overload transmission lines or threaten stability limits. Reliability coordinators can use TLRs to reduce such power flows. Requests are normally activated within 30 to 60 minutes of being received. TLRs are typically used to manage relatively small adjustments of between 25 and 50 MWs.*

Figure 12

Overview of the Regional Cascade Sequence



Source: US-Canada Power Outage Task Force (2004a) west (Illinois and Missouri) to load centers in northern Ohio, eastern Michigan and Ontario (Figure 12, Panel 1).

Failure of the Sammis-Star line induced unplanned shifts of power across the region, hastened by Zone 3 impedance relays[23] (Figure 12, Panel 2).

A series of lines in northern Ohio tripped as a result of overloads, causing a series of shifts in power flows and loadings, but the system stabilised after each (Figure 12, Panel 3).

After 4.10:36 pm, the power surges resulting from the FE system failures caused lines in neighbouring areas to see overloads that caused impedance relays to operate. The result was a wave of line trips through western Ohio that separated the AEP control area from the FE control area. The line trips progressed northward into Michigan separating western and eastern Michigan, causing a power flow reversal within Michigan toward Cleveland. Many of these line trips were from Zone 3 impedance relay actions that accelerated the speed of the line trips and reduced the potential time in which grid operators might have identified and responded to the growing problem (Figure 12, Panel 4).

With paths cut from the west, a massive power surge flowed from PJM into New York and Ontario in a counter-clockwise flow around Lake Erie to serve the load still connected in eastern Michigan and northern Ohio. Relays on transmission lines between PJM and New York saw this massive power surge as faults and tripped those lines. Ontario's east-west tie line also became overloaded and tripped.

The entire northeastern United States and eastern Ontario then became a large electrical island separated from the rest of the Eastern Interconnection. This large area, which had been importing power prior to the cascade, quickly became unstable after 4:10.38 pm as there was insufficient generation on-line within the island to meet electricity demand. Systems to the south and west of the split, such as PJM and AEP remained intact and were mostly unaffected by the outage. Once the northeast split from the rest of the Eastern Interconnection, the cascade was isolated (Figure 12, Panels 5 to 9).

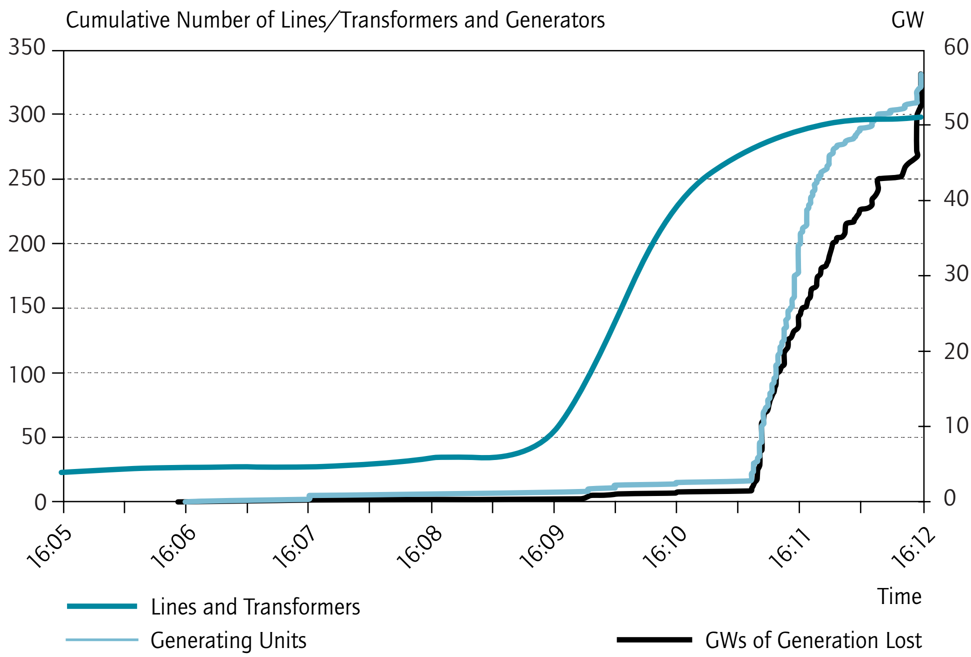
After 4.10:46 pm, the large electrical island in the Northeast had less generation than load, and was unstable with large power surges and swings in frequency and voltage. As a result, many lines and generators across the disturbance area tripped, breaking the area into several electrical islands.

23. Impedance relays are designed to detect currents and voltages outside normal operating parameters, resulting from system faults, and to disconnect transmission lines before they suffer damage. A relay is installed at each end of a transmission line, with each relay monitoring up to 3 zones or lengths of transmission line. Zone 1 is set to monitor 80% of the line next to the relay and to trip with no time delay when a fault is detected. Zone 2 is set to monitor the entire line and slightly beyond, and to trip with a slight delay when a fault is detected, while Zone 3 is set to monitor well beyond the end of the line and act more like a remote relay or back-up circuit breaker. Zone 3 relays should not trip under typical emergency conditions. However, in practice impedance relays may trip in response to 'apparent' faults caused by large swings in voltage or current.

Generation and load within these smaller islands was often unbalanced, leading to further tripping of lines and generating units until equilibrium was established in each island or they blacked out. Figure 13 shows the accelerating pace of line and generator trips during the regional cascade phase of the event, and the related loss of generating capacity.

Figure 13

Line and Generation Trips, and Lost Load During the Cascade Phase



Source: US-Canada Power Outage Task Force (2004a)

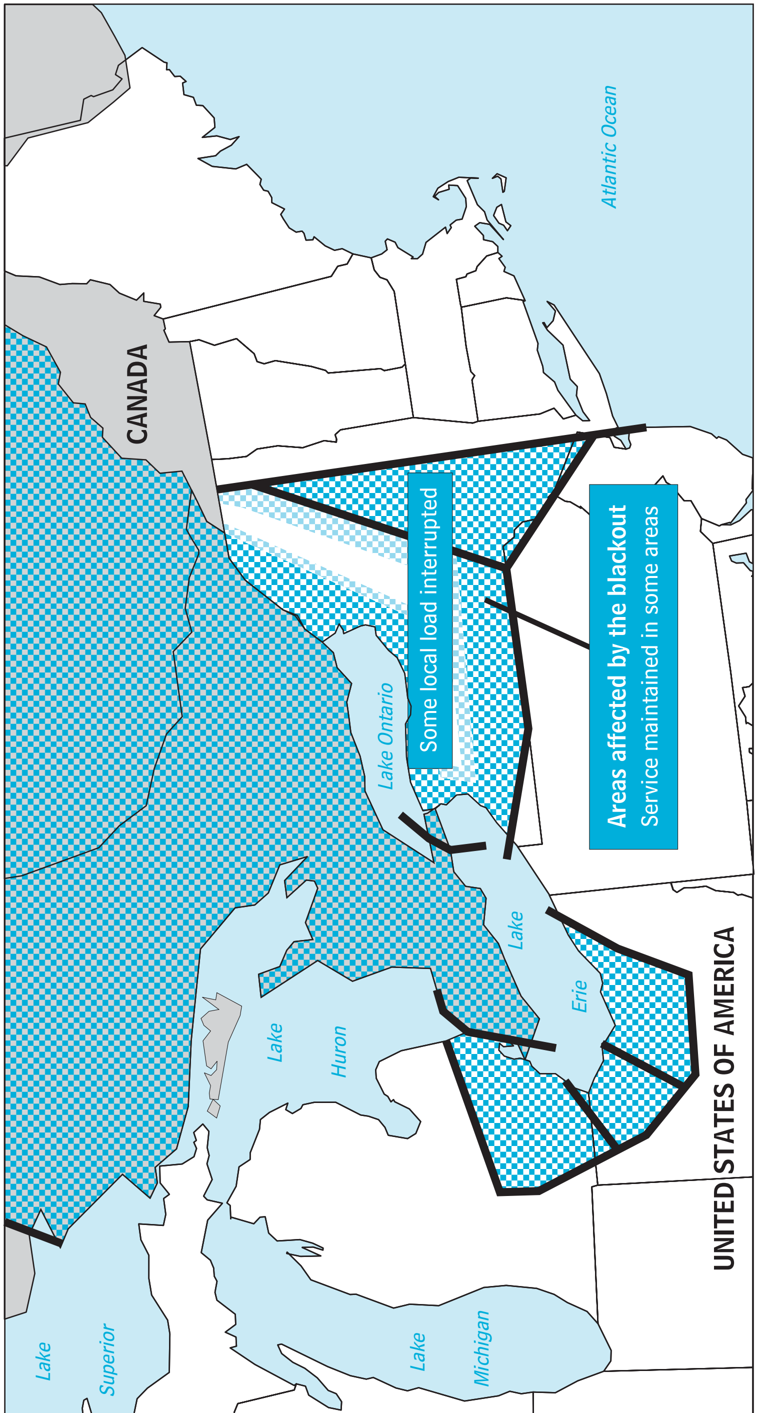
At that stage, most of the Northeast was blacked out (the area shown in gray in Figure 12, Panel 10). Some isolated areas of generation and load remained on-line for several minutes, while some of those areas in which a close generation-load balance could be maintained remained operational.

Impact and Restoration

Once the regional cascade was complete, large portions of the Midwest and Northeast United States and Ontario, Canada had been disconnected. At least 265 power plants and over 500 individual generating units had shut down.

Figure 14

Area Affected by the US-Canadian Blackout



Source: NERC (2004c).

Overall, 61,800 MW of load was lost in the states of Ohio, Michigan, Pennsylvania, New York, New Jersey, Connecticut, Vermont, Massachusetts and in the Canadian province of Ontario. Around 50 million people were disconnected initially. Figure 14 shows the area affected by the blackout.

In the United States, the economic cost of the disruption has been estimated at between USD 4 billion and USD 10 billion[24]. In Canada, gross domestic product fell by around 0.7% in August, with 18.9 million working hours lost and manufacturing shipments down by CAD 2.3 billion[25].

Restoration Process

Most services were restored in the United States within two days, with all services fully restored within four days. A regional summary of service restoration in the United States is presented in Table 3.

Restoration proceeded in accordance with established restoration and black-start procedures. Initial capacity shortages were managed through rotating load shedding.

Restoration was greatly assisted by the ability to energize transmission from neighboring systems and by some relatively large islands that survived the event. One such island of approximately 5,700 MW around the Niagara area formed the basis for restoration in both New York and Ontario. Another island consisting of most of New England in the United States and the Maritime Provinces in Canada stabilised after the event allowing relatively quick restoration of many local area services.

The reliability regions most affected by the blackout - East Central Area Reliability Coordination Agreement (ECAR), the Northeast Power Coordinating Council (NPCC) and the Mid-Atlantic Area Council (MAAC) – have reviewed the restoration process in their reliability regions. Key recommendations from these investigations are summarized in the North American Electric Reliability Council's recent status report on implementation of the 2003 Blackout recommendations[26], and include:

- Restoration criteria and guides need to be kept up to date.
- Voice communications between system operators and reliability coordinators could be improved. Conference call protocols could be improved. For instance, "open" conference calls could be used to facilitate

24. ELCON (2004).

25. Statistics Canada (2003a) and (2003b).

26. NERC (2005b).

Table 3

Service Restoration in the United States

Utility/Power Pool (NERC Region)	Area Affected	Capacity Loss (MW)	Restoration	
			Date and Time	Period (Hours)
Midwest Independent System Operator (ECAR)	Geographic areas for MISO reliability coordination footprint: Michigan and Ohio	18 500	Approximately 8/17/03, 5:00 pm	74
Detroit Edison (ECAR)	Southeastern Michigan including Detroit	11 000	8/16/03, 7:00 am	39
Consumers Power (ECAR)	Southern Lower Michigan and small areas near Flint, Alma, Saginaw, and Lansing Michigan	1 007	8/16/03, 1:03 pm	45
First Energy Corporation (ECAR)	Northeast, Ohio	7 000	8/16/03, 8:27 pm	52
ISO New England (NPCC)	Southwestern Connecticut and a portion of Western Massachusetts and Vermont	2 500	8/16/03, 3:45 am (restoration ended) 8/17/03, 7:00 pm (incident ended)	76
New York ISO (NPCC)	New York State	22 934	8/18/03, 12:03 am	80
Niagara Mohawk (NPCC)	New York- Buffalo to Albany; Ontario, Canada to Pennsylvania	Not Available	8/14/03, 11:48 pm	8
PJM Interconnection, LLC (MAAC)	Northern New Jersey Erie, Pennsylvania area	4 500	Approximately 8/15/03, 6:00 am	14
Consolidated Edison Co of New York (NPCC)	5 boroughs of NYC and Westchester County	11 202	8/15/03, 9:03 pm	29

Source: US Energy Information Administration, Electricity Power Monthly December 2003 [DOE/EIA-0226 (2003/12)].

communication between reliability coordinators, and, more locally, between transmission operators and balancing authorities. Backup communications procedures should be regularly tested to verify their availability and effectiveness. Consideration could be given to more effective means of managing incoming phone calls.

- Access to real-time system information could be improved to help strengthen system operator situational awareness during restoration and to support more effective management of alarm systems.
- Contingency analysis should be improved during restoration.
- Training exercises should be established to improve system operator capacity to undertake efficient, coordinated restoration. Drills could focus on synchronizing procedures (with generators and in the event that load "islands" emerge), and stabilizing procedures (to ensure that generation and demand can be matched to preserve "island" operation in emergency situations).
- Adequate facilities need to be made available to accommodate additional staff, and adequate fuel needs to be stored for emergency power supply.
- Load management during restoration should be improved. Public appeals to reduce demand could be employed and more effective forms of rotating load shedding could be developed and implemented to support more efficient restoration. Exchanges between control areas could also be improved to support more timely restoration of services.

All NERC regions are in the process of reviewing their blackstart and system restoration plans and procedures, and making necessary revisions.

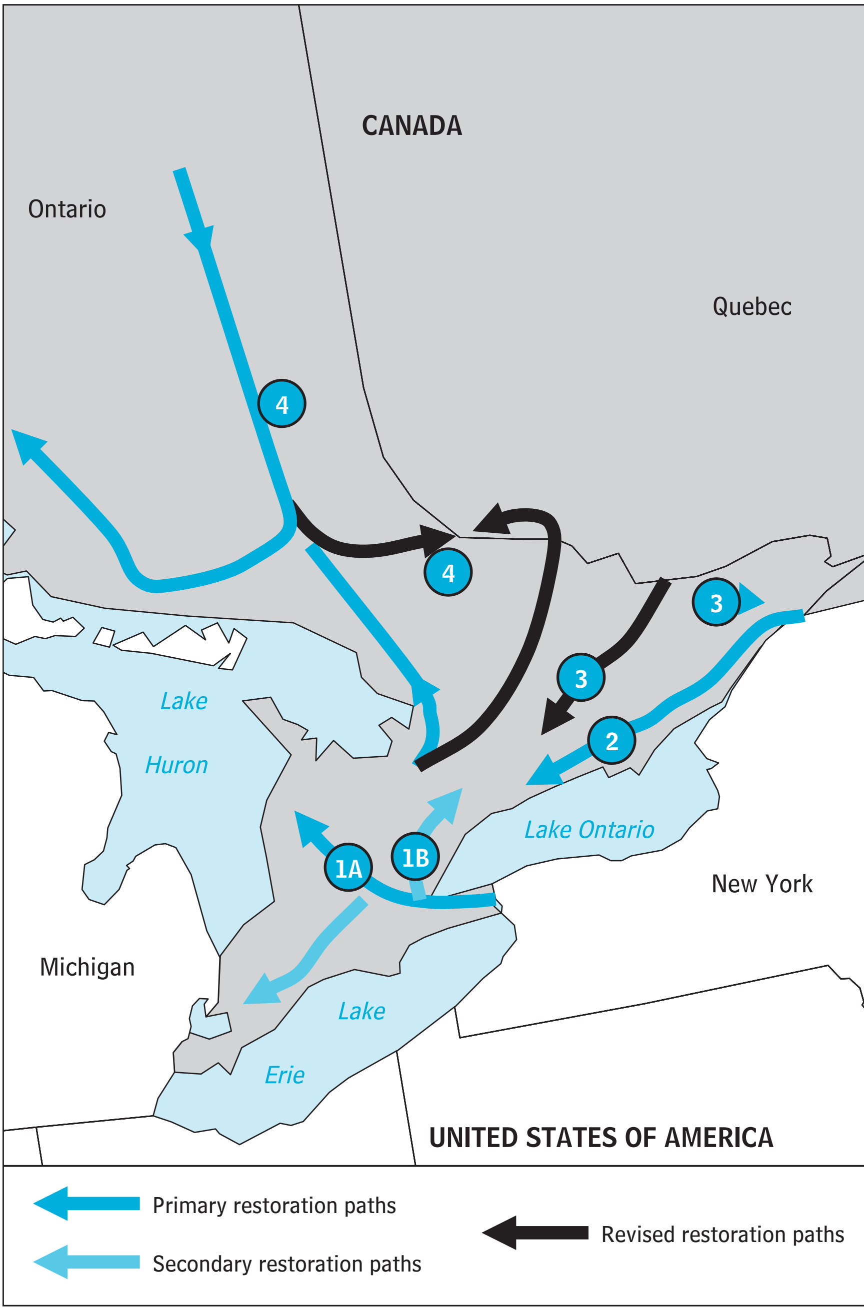
In Ontario[27], a provincial state of emergency was declared, followed by suspension of the wholesale electricity market at 4.20 pm on 14 August. With the market suspended, Ontario's Independent Electricity Market Operator (IMO – now known as the Independent Electricity System Operator) began issuing manual dispatch instructions to coordinate the restoration of the system.

IMO's first priority was to assess the extent of the disturbance and its implications for implementing the Ontario Power System Restoration Plan. Five electrical islands had survived in Ontario and these provided the basis for rebuilding the power system. Five key restoration paths were identified with restoration undertaken on each path simultaneously and independently, by building on surviving electrical islands and gradually adding generation and load. Figure 15 provides an overview of the restoration process in Ontario.

27. IMO (2003) and (2004) for further information about the restoration process in Ontario.

Figure 15

Restoration Strategy in Ontario



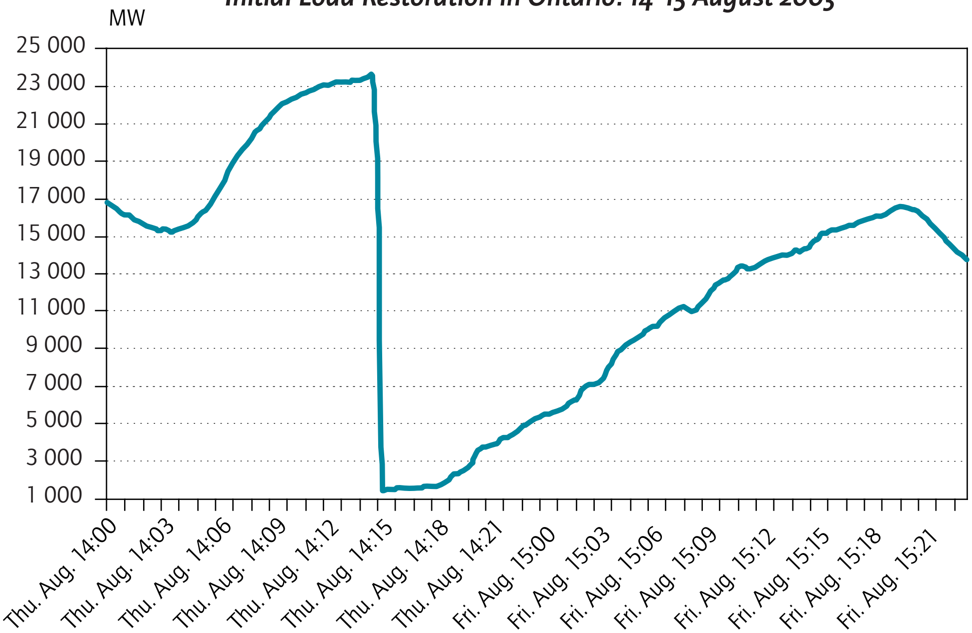
Source: IMO (2004)

Ontario's basic minimum power system was reestablished at 5.20 am on August 15, a little over 13 hours after the blackout. Restoration of the IMO controlled grid was completed at 6.26 pm on August 15 (with the exception of the Ontario-Michigan interconnections), 26 hours and 16 minutes after the blackout. The Ontario-Michigan interconnection was re-established on August 17 at 7.46 pm.

Although grid supply had been restored, some generators could not return to service for several days, aggravating an already tight supply situation in Ontario. From this point, priority was given to restoring generating capacity, while rotational load shedding was implemented to help manage the initial shortage[28]. Initial load restoration over this period is shown in Figure 16.

Figure 16

Initial Load Restoration in Ontario: 14-15 August 2003



Source: IMO (2004).

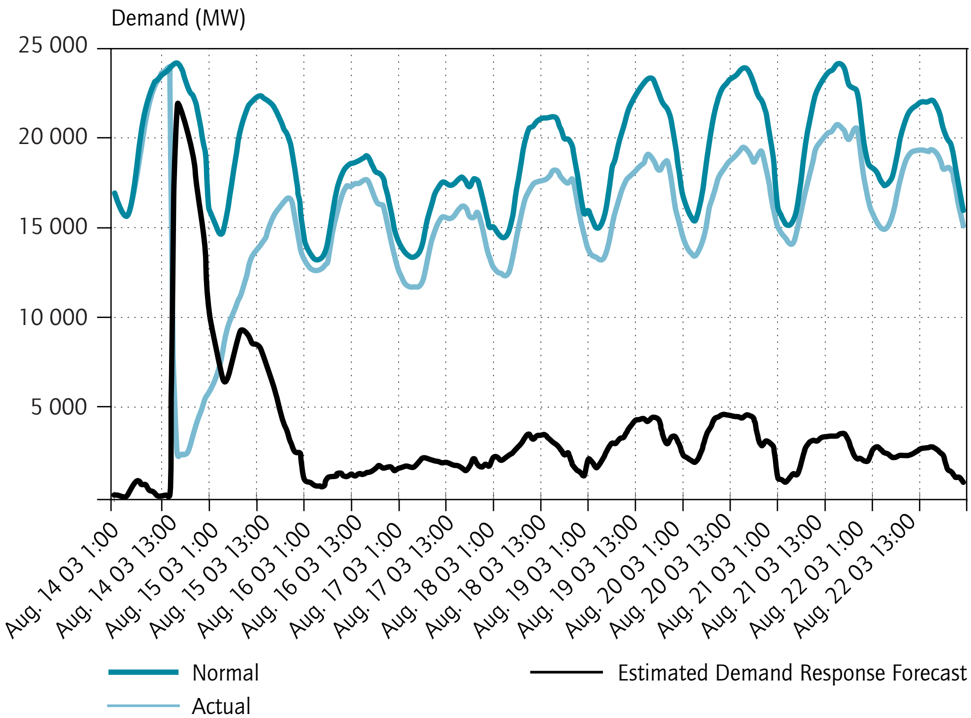
On August 17, the government of Ontario issued an urgent appeal to all consumers to reduce their use of electricity by 50% for the duration of the

28. *Rotational load shedding was used to restrict loads served by distributors to approximately 75% of normal levels until all loads were restored at 10.40 pm on 15 August. See IMO (2004) for further details.*

provincial emergency. Figure 17 illustrates Ontario's actual and forecast load for August 14 to 22 (when the emergency was lifted). The demand response curve shows a significant customer response.

Figure 17

Load Restoration in Ontario: 14-22 August 2003



Source: IMO (2004).

The provincial emergency lasted for 9 days and was terminated by the Ontario government at 8.00 pm, 22 August. The Ontario Power Market resumed normal operations from midnight, 22 August.

Key Findings of Investigations and Inquiries

Comprehensive investigations of the nature and causes of this event were undertaken by the US-Canada Power System Outage Task Force (the Task Force) and by the North American Electric Reliability Council (NERC)[29].

29. See US-Canada Power System Outage Task Force (2004a) and NERC (2004c) for further details.

The Final Report of the Task Force identified four groups of causes for the Ohio phase of the blackout:

- **Inadequate System Understanding**. The Task Force concluded that FE and ECAR (FE's reliability coordinator) failed to understand, assess and effectively manage the vulnerabilities of the FE system, particularly in relation to the Cleveland-Akron area. FE did not undertake rigorous long-term planning studies of its system, nor did it conduct appropriate multiple contingency analysis for its control area. FE's voltage analysis and operational voltage criteria were inadequate and did not reflect actual voltage stability conditions or needs. ECAR did not independently review or correct FE's inappropriate operational practises. Some NERC planning and operational standards were sufficiently ambiguous to enable FE to adopt inadequate operational practises.
- **Inadequate Situational Awareness**. FE was unaware of the deteriorating condition of its system and failed to ensure the security of its transmission network following significant contingency events. FE did not have the capacity to run regular contingency analysis. It also lacked procedures to monitor the status of its key system monitoring equipment or to test the functionality of this equipment following repairs. Additional monitoring tools were not available to facilitate effective system operation once the primary alarm systems had failed. Communications between computer support staff and operators was ineffective.
- **Inadequate Tree Trimming**. FE failed to undertake effective vegetation management of easements associated with its 345 kV network. Contact with trees was the principal cause of three 345 kV and one 138 kV transmission line failure.
- **Inadequate Diagnostic Support from Reliability Coordinators**. The reliability coordinators responsible for overseeing secure regional operations failed to provide effective real-time diagnostic support. The absence of real-time information on the operational status of transmission flowgates precluded MISO from detecting N-1 security violations in FE's system. The situation was exacerbated on the day by an absence of real-time data from the Stuart-Atlanta transmission line. A lack of real-time information prevented MISO from diagnosing FE's system problems in a timely manner, degrading its capacity to provide effective diagnostic assistance or direction. MISO also lacked an effective means of identifying the location or significance of transmission line trips reported by its EMS. PJM and MISO also lacked procedures to coordinate a response to an N-1 violation observed in one another's area.

The investigation also concluded that protection devices acted to accelerate the cascade sequence and to increase the magnitude of the disruption. Impedance relays on transmission lines and protective devices on generators are designed to detect high currents and low voltages resulting from system faults and to disconnect equipment when such faults are registered to protect them from being damaged. However, multiple contingency events can send transient oscillations through interconnected alternating current networks, which can be misinterpreted as faults by protection devices, leading to erroneous tripping of equipment. During the event, protective devices, especially Zone 3 impedance relays on transmission lines, activated so quickly that system operators did not have an opportunity to initiate any emergency actions. The Task Force report notes that most transmission lines affected at the time could have carried the likely resulting overloads for at least 15 minutes and possibly up to an hour without sustaining significant damage, which might have provided sufficient time for effective emergency intervention to limit the impact of the event.

In addition, the North American Electric Reliability Council's initial investigations identified several violations of its operating policies and planning standards, which in its view directly contributed to causing the outage, including those listed below.

- Following the outage of the Chamberlin-Harding 345 kV line, FE operating personnel did not take the necessary action to return the system to a safe operating state as required by NERC Policy 2, Section A, Standard 1.
- FE operations personnel did not adequately communicate FE's emergency operating conditions to neighboring systems as required by NERC Policy 5, Section A.
- FE's state estimation and contingency analysis tools were not used to assess system conditions, violating NERC Operating Policy 5, Section C, Requirement 3, and Policy 4, Section A, Requirement 5.
- MISO did not notify other reliability coordinators of potential system problems as required by NERC Policy 9, Section C, Requirement 2.
- 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.
- PJM and MISO, as reliability coordinators, lacked procedures or guidelines between their respective organisations 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.

- FE's operational monitoring equipment was not adequate to alert FE's operators about important deviations in operating conditions and the need for corrective action as required by NERC Policy 4, Section A, Requirement 5[30].

Investigations also found that restoration of services in the United States and Canada had generally been undertaken in a timely and effective manner given the magnitude of the disturbance. The Ontario IMO concluded that effective collaboration throughout the supply chain had helped to eliminate restoration errors and minimise the outage period. However the IMO's report also noted opportunities to improve future restoration processes particularly in relation to the management of emergency load shedding and operational communications. Investigations on the US side are continuing[31].

Key Recommendations

Recommendations proposed by the Task Force and by NERC are presented in Annex 1, along with a summary of the implementation status. These investigations proposed over 60 recommendations. Key issues raised in the recommendations included the need to:

- improve governance, regulation and enforcement, in particular by clarifying the regulatory standards, clarifying the responsibilities and accountabilities of parties subject to those standards, and by strengthening accountability through mandatory application and enforcement of those standards;
- improve system operator training, particularly in relation to managing emergency events and avoiding future emergency events through more effective management of near emergency conditions;
- ensure system operation is supported by effective diagnostic and management tools and information, facilitate real-time multiple contingency analysis, system monitoring and operational management;
- clarify and strengthen standards and operating practises relating to vegetation management; and
- improve coordination, communication and data exchange between system operators and reliability coordinators at a local and regional level.

30. See US-Canada Power System Outage Task Force (2004a) and NERC (2004a) for details.

31. See IMO (2004) for further details.

CASE STUDY 2: Switzerland and Italy

Italy's worst supply disruption in over 50 years struck on Sunday, 28 September 2003. Parts of southern Switzerland were also affected. Cascading failure of the interconnectors serving Italy led to the separation of the Italian grid from the Union for the Co-ordination of Transmission of Electricity (UCTE) system. Separation created highly unstable operating conditions throughout the Italian system, causing widespread generator and line trips. Emergency responses were unable to arrest the situation and the Italian system collapsed around 3.30 am. The following event summary is largely drawn from the final report of the UCTE Italian Blackout Investigation Committee[32].

The event started at around 3.01 am on 28 September 2003 with the failure of the Swiss 380 kV line Mettlen-Lavorgo (also known as the "Lukmanier" line). The line was relatively heavily loaded just prior to its failure, with loading levels at around 86% of maximum rated capacity. High loading levels result in overheating of conductors, which causes transmission lines to sag, increasing the potential for a short circuit caused by an electric arc between a line and a grounded object, such as a tree (ie. a flashover), or possibly by direct contact with a grounded object. The Mettlen-Lavorgo line failed as a result of a flashover with a tree.

ETRANS (the Swiss high voltage transmission system co-ordinator) made several attempts to automatically reclose the line without success. A manual attempt at 3.08 am also failed. Reclosure after a line trip of this kind is standard operating practice, allowing lines to be reconnected where they remain physically intact. However, on this occasion reclosure attempts failed because of high power flows into Italy at the time, which had created a high phase angle[33] difference in voltages at either end of the line. This phase angle difference exceeded the stability limits set for the line and resulted in its protection devices cutting in to prevent reclosure.

At 3.11 am, a phone conversation took place between the ETRANS coordination centre in Laufenburg and the Gestore della Rete di Trasmissione Nazional (GRTN – the Italian transmission system operator) control centre in Rome. ETRANS asked GRTN to activate countermeasures within the Italian system, in order to

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32. UCTE (2004a).

33. Phase angles measure the difference in voltage caused by the voltage at the load end of the line being out of phase with the voltage at the generator end. This difference determines the rate at which power flows along a line from generation to load in an AC environment. The greater the phase angle difference the greater the power flow. However, power flow only increases until the phase difference between two voltages reaches 90°, after which the power transfer becomes unstable possibly leading to voltage collapse and damage to infrastructure. This is a theoretical maximum. Power lines are never run near this limit. In practise, lower limits of between 30° and 45° are typically set and these form a stability limit for power flows on a transmission line.

help relieve the overloads in Switzerland and return the system to a secure state. In essence, the request was to reduce Italian imports by 300 MW, because Italy was at that time importing around 300 MW more than the scheduled power transfers, which amounted to 6 400 MW on the northern border.

The reduction of Italian imports by about 300 MW took effect at 3.21 am, 10 minutes after the phone call and returned Italy close to the agreed schedule. However, the import reduction together with internal countermeasures taken within the Swiss system was insufficient to relieve the overload.

After the loss of the Mettlen-Lavorgo line, loads on neighboring lines increased. In particular, the Swiss 380 kV Sils-Soazza line (also called the "San Bernardino" line) was operating at 110% of its normal maximum rated capacity following the loss of the Mettlen-Lavorgo line. According to UCTE operating standards, an overload of this magnitude can be maintained in emergency circumstances, but only for a short period. Under the operating standards, the system operator had no more than 15 minutes to eliminate the overload. At 3.25:21 am, around 24 minutes after the loss of the Mettlen-Lavorgo line, the Sils-Soazza line also tripped as a result of a flashover with a tree. The UCTE Investigating Committee concluded that this flashover was probably caused by the sag in the line, due to overheating of the conductors.

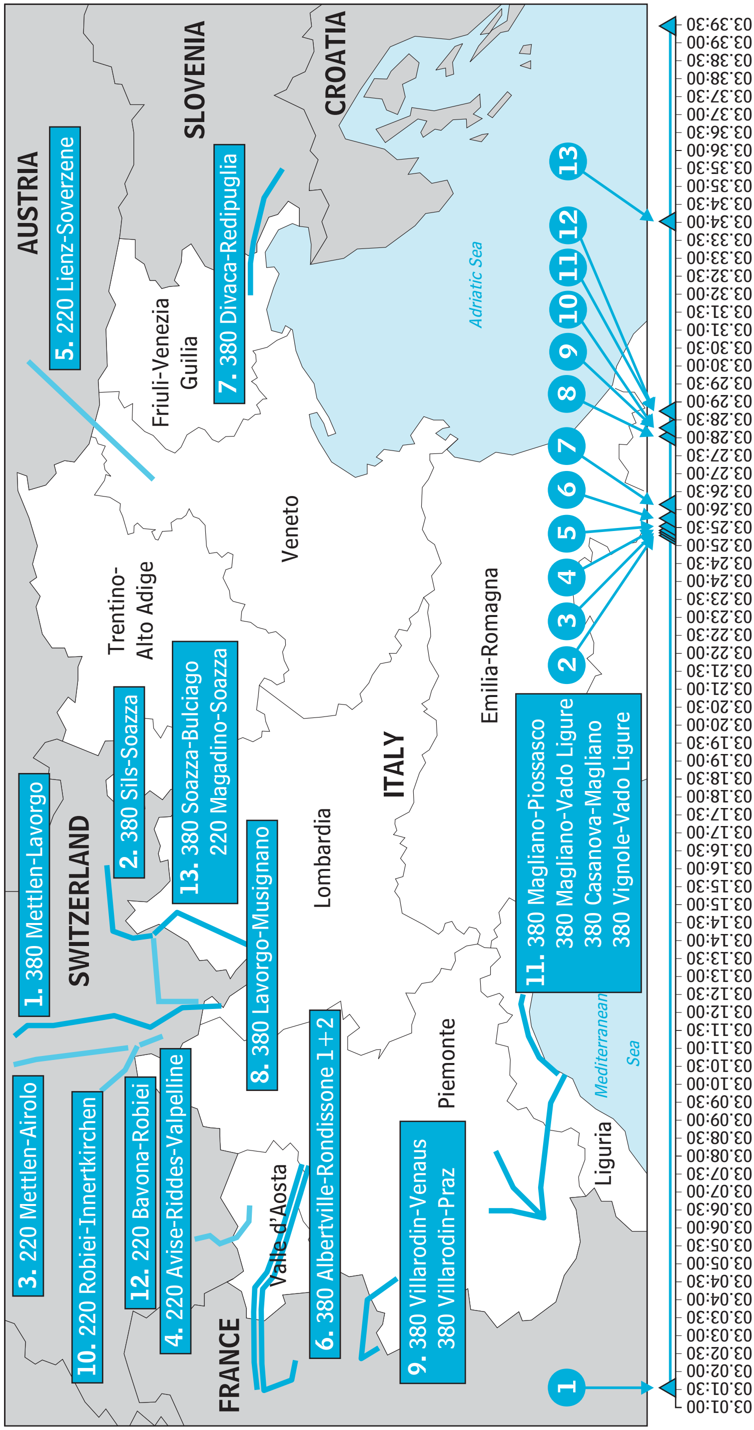
A significant part of the additional power flow resulting from failure of the Sils-Soazza line was redistributed to an internal 220 kV line in Switzerland (the Mettlen-Airolo line), which became highly overloaded and was tripped by its protection devices almost immediately. Other Swiss 220 kV lines in the area subsequently tripped due to overloads, separating the southern part of Switzerland from the Swiss network.

Loss of the Mettlen-Lavorgo and Sils-Soazza lines also created substantial overloads on the other transmission lines in the area. The remaining lines from Riddes and Robbia to Italy then tripped, leading to an overload on the interconnectors with France. This overload caused a significant and rapid decrease in voltage at the French border. Low voltages and high currents caused protection devices to trip the French 380 kV Albertville-La Coche-Praz line.

At this point the Italian system lost synchronisation with the UCTE network and all remaining interconnectors were disconnected almost simultaneously by their automatic protection devices. The Italian system was isolated from the UCTE network about 12 seconds after the loss of the Sils-Soazza line, at around 3.25:34 am. A weak 220/132 kV interconnection remained with Slovenia till it tripped at around 3.26:30 am, after which disconnection was complete. Disconnection largely occurred along the Italian borders with

Figure 18

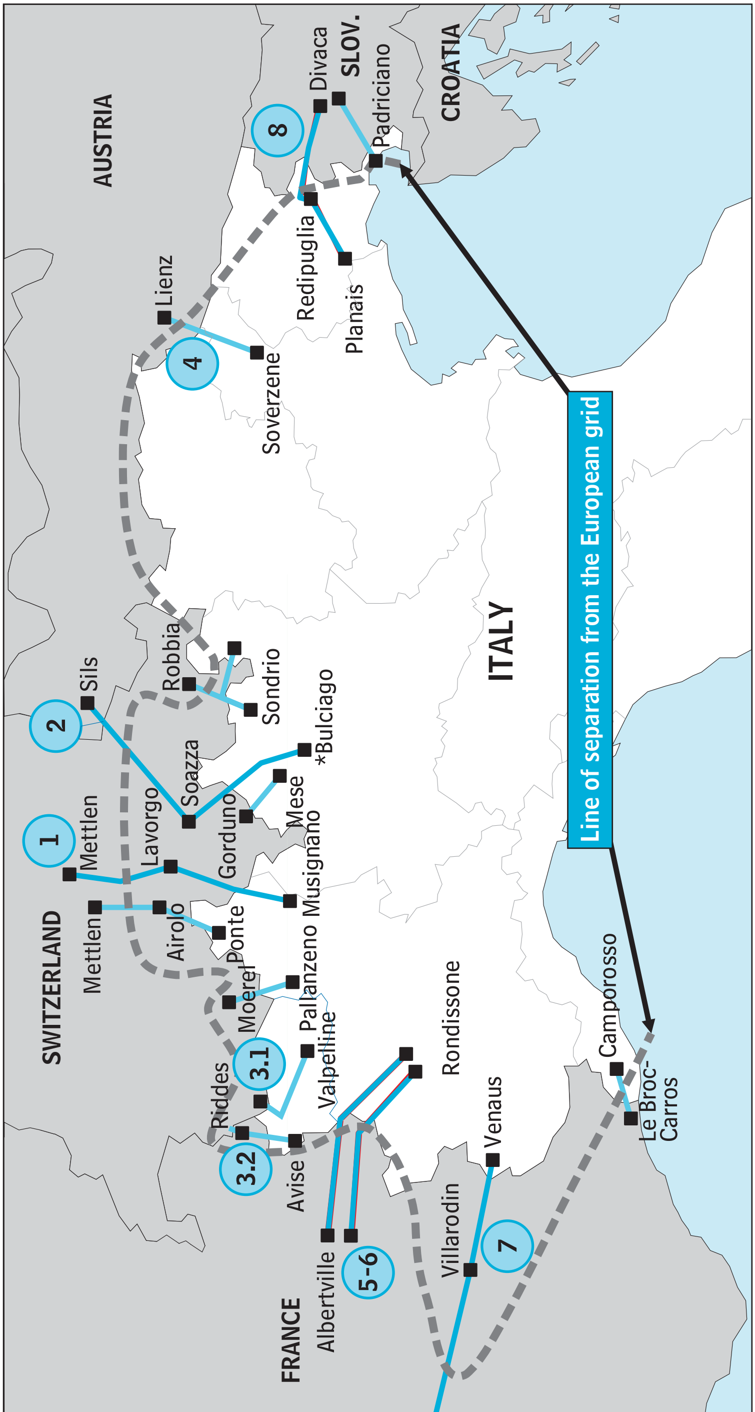
Overview of the Italian Interconnector Separation Sequence



Source: UCTE (2004a)

Figure 19

Final Line of Separation of the Italian Transmission System from the UCTE Transmission Network



Source: UCTE (2004a)

France, Switzerland and Austria. Pockets within France and Switzerland were also disconnected. On the Slovenian border, disconnection occurred within Italy. An overview of the interconnector separation sequence and the final line of separation of the Italian transmission system from the continental European transmission network are presented in Figure 18 and Figure 19.

During the 12 seconds of very high overloads, instability phenomena started in the affected area of the system. This led to very low voltage levels in northern Italy that tripped several Italian generators. Separation from the UCTE network created a large generation deficit of nearly 6 650 MW, which also caused a fast frequency drop throughout the Italian system.

GRTN's under-frequency load-shedding plan automatically activated. The plan was designed to cover between 50% and 60% of total Italian demand, and was especially calibrated for response during peak periods. The plan involved stepped shedding of pump storage plants, large industrials and other high voltage and medium voltage users. However, implementation was 'hard wired', which meant that it was not possible to quickly modify implementation to account for the specific characteristics of load at the time of the event. Once the pump storage units had been shed, the remaining load available to be shed at around 3.30 am accounted for less than 11,000 MW. Much of the remaining load was residential and largely excluded from the defense plan due to binding contractual and legal conditions. Although the plan operated as programmed, its effectiveness was probably reduced by the relative lack of available load to shed during the early hours on a Sunday morning.

Primary frequency control combined with automatic shedding of the pumped storage power plants and some industrial demand helped to slow the rate of decline. However, it was insufficient to prevent the ultimate collapse of the islanded Italian system. Figure 20 provides a summary of the key events during the transitory period until system collapse.

Additional generating units tripped for various reasons that typically reflected under-frequency relay operation or the activation of gas turbine protection devices. Despite additional load shedding, the frequency continued to decline and the system collapsed 2 minutes and 30 seconds after the separation when the frequency within the Italian system reached the threshold of 47.5 Hz at around 3.30 am.

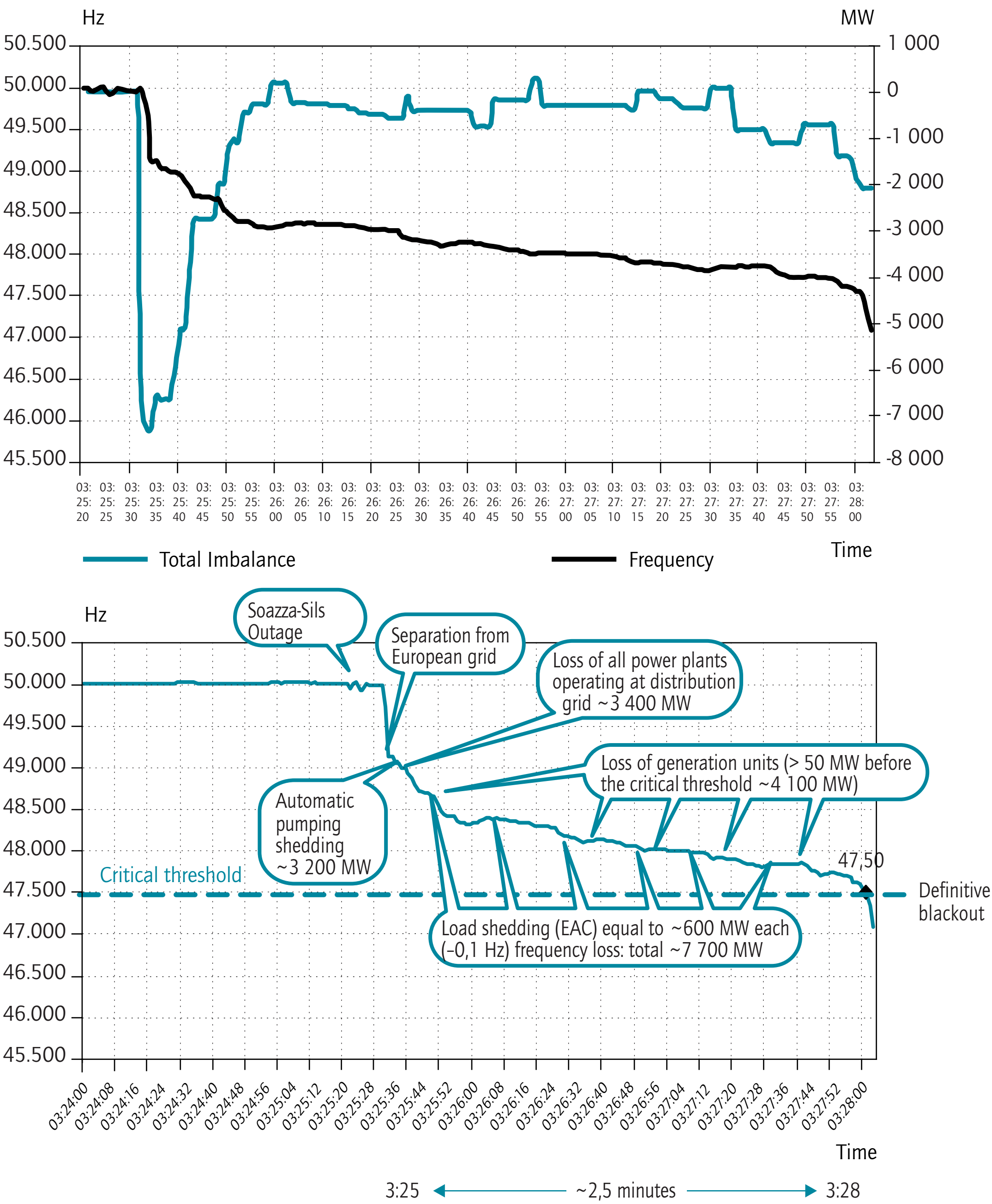
Following the separation, the significant fall in load on the UCTE system resulting from the loss of demand in Italy led to a sharp increase in frequency

42. *IEA 2005c.*

43. *EFET, 2004.*

Figure 20

Key Events during the Transitory Period



Source: UCTE (2004a).

across the UCTE network, creating a potential danger for system security across continental Europe. Some generating units were tripped by over-frequency and under-voltage relays. Although loading on lines from France to Germany to Belgium increased significantly, system operators successfully implemented emergency responses that quarantined the effects of the outage and prevented a cascading failure across the UCTE network.

Impact and Restoration

Immediately after the event, all of Italy (with the exception of Sardinia), a portion of southern Switzerland up to the outskirts of Geneva, and a small area within France near the Italian border was disconnected. Over 340 power plants operating at the time in Italy had been shut down, representing a loss of over 20 500 MW of domestic generation. Around 6 600 MW of electricity imports to Italy had also been lost. Over 27 000 MW of load was lost at the time of the failure. Around 55 million people were initially disconnected. The economic cost of the disruption has been estimated at around USD 139 million[34].

31 thermal units initiated the sequence to switch to in-house operating mode prior to system collapse. However, only 8 of these plants completed the sequence, allowing them to remain in operation after the collapse and to provide immediate support for restoration activities. Two small electrical islands continued to operate following the general collapse: one south of Rome and the other in the south western region of Calabria. These electrical islands helped support restoration of services in the southern and central regions.

Restoration Process

In Switzerland, services were largely restored within 1.5 hours. The San Bernardino region was the exception, where lengthy interruptions continued until the afternoon.

In Italy, restoration proceeded according to GRTN's established plan. The plan was based on implementing several restoration paths in parallel to restore auxiliary services to shut down power plants and to reconnect thermal plants that either succeeded in maintaining operation within an electrical island or by switching to in-house operating mode. Implementation proceeded once operators had a clear understanding of the nature of the outage and was managed with caution to avoid further service failures. Load was progressively added to the islands that emerged from each restoration path. Strategic level implementation was planned, coordinated and supervised centrally. However,

34. OXERA (2005).

many initial activities were undertaken locally and autonomously, with central coordination taking over as the islands developed and were ultimately reintegrated. A key objective was to restore services in the shortest possible time, especially to metropolitan areas.

In practice, timely and successful implementation of the restoration plan was influenced by the limited availability of base-load thermal units which remained operational after the collapse; the availability of hydro and gas-fired generators to provide black-start services, particularly voltage and frequency control as load was restored; and the reliability of telecommunications systems to support coordinated restoration activities.

Although some difficulties were encountered, the UCTE Investigation Committee considers that given the severity of the outage the restoration process was timely and successfully performed. However, the duration of the emergency may have been reduced if more generating units had managed to switch successfully to in-house operating mode or if more of the black-start capable plants had been operational.

The main 380 kV network was re-energised 13.5 hours after the initial collapse. Fifty percent of load was reconnected after 6.5 hours, 70% was reconnected after 10 hours and 99% was reconnected after 15 hours. Services were completely restored to all consumers 18 hours and 12 minutes after the outage. The UCTE Investigation Committee estimates that around 177 GWh of energy was not supplied as a result of the outage.

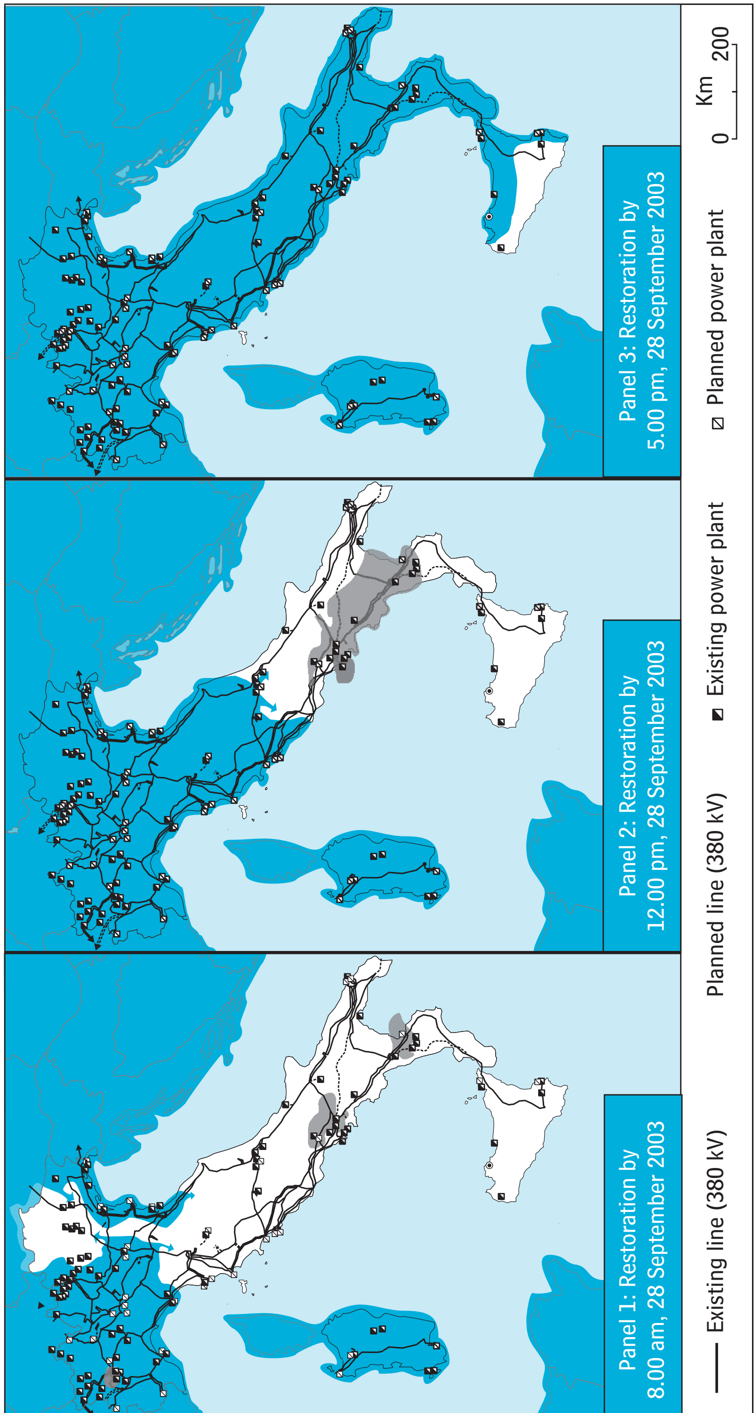
Twenty-six restoration paths were used, with service restoration largely progressing from north to south. Figure 21 provides a diagrammatic overview of the restoration process.

Approximately three hours after the outage, services to the northwestern region of Italy had been almost completely restored and reconnected with the French network. Hydroelectric generation was available to progressively re-supply load in this area, while around 750 MW of thermal capacity had completed the initial start-up sequence in the Lombardy region. The Lombardy region was also being supplied through two energised transmission backbones that had been synchronised with the UCTE system through interconnections with Switzerland. Services had also been restored to parts of northern Florence through a connection with Lombardy, and to eastern and northern Venice through interconnections with Slovenia.

By 8.00 am, the northern network had been re-energised and was operating synchronously with the UCTE system. No significant progress had been made on restoring services in the central region. Restoration progress was delayed

Figure 21

Restoration Progress Following the Italian Blackout



Source: UCTE (2004a)

in the southern region by telecommunications failures and remote control problems with some sub-stations on the preferred restoration paths. Panel 1 of Figure 21 shows progress by 8.00 am.

Between 8.00 am and 12.00 pm restoration continued more slowly than expected due to technical difficulties with switching operations at sub-stations, and telecommunications outages which continued to complicate restoration. In particular, loss of the telecommunications network around Naples and Palermo led to a loss of all SCADA data for these areas between 8.50 am and 12.03 pm and between 8.50 am and 1.17 pm respectively. This complicated coordination of activities and re-supply in the central and southern regions. Progressive depletion of the hydro reservoirs, which had not been fully replenished as a result of the outage the night before, emerged as a significant issue with the potential to disrupt the restoration effort. GRTN asked distributors to interrupt industrial loads and implement the first level of rotating load shedding between 11.00 am and 6.00 pm in the northern and central-northern regions. However, the response was not effective.

By 12.00 pm load in the northern region was mostly restored. In the southern region the two electrical islands south of Rome and southwest of Calabria were reintegrated and expanded. Panel 2 of Figure 21 shows the progress of restoration by 12.00 pm.

From noon, the focus of the restoration shifted toward re-supplying central and southern Italy and Sicily as soon as possible. The relative weakness of the transmission backbone from northern to central-southern Italy combined with the lack of available generation in the central-southern regions had induced high power flows from north to south, creating a phase angle risk. Restoration of the 500 MW interconnection with Greece helped strengthen system security and allowed some additional domestic capacity to be released from maintaining system security to serve load. Services were restored to metropolitan Rome at 1.17 pm. Panel 3 of Figure 21 shows that services had been largely restored to Italy by 5.00 pm. The interconnection with the UCTE network had also been fully restored.

Progress during the initial phases of restoration was slowed by the relatively small number of thermal plants that had managed to switch to in-house operating mode, and by failures and difficulties in starting the black-start power plants. A lack of information on the primary causes of the outage also slowed implementation, while problems with voice and data communications hindered restoration. Implementation and coordination difficulties were typically overcome by employing alternative restoration routes and by issuing instructions over the phone. UCTE reserves were also used to facilitate black-start activities and progressive restoration of load once sufficient interconnection had been restored.

Restoration of services in Sicily proved more difficult than expected. Several attempts to restore services independently without interconnection failed. Ultimately, restoration was undertaken using the interconnection with Calabria. However, power exchange on the interconnector was effectively limited to 200 MW. Power exchange limitations combined with the need to direct scarce generation capacity to meet the evening peak slowed the pace of restoration. Emergency conditions were terminated with the restoration of power supplies to Sicily at 9.40 pm.

Key Findings of Investigations and Inquiries

Several official investigations of the event have been undertaken, most notably by the Swiss Federal Office of Energy, through the joint report by the Italian and French regulators and by the UCTE.

Table 4 summarises UCTE's analysis of the key underlying causes of the event, the relative impact of each cause on the event and the actions initiated in response to the event. The influence of the underlying causes on system security leading to the outage is summarised in Figure 22.

The UCTE Investigating Committee Final Report notes that the integrated system was operating in an N-1 secure state, consistent with UCTE operating procedures, prior to the failure of the Mettlen-Lavorgo line. The inability of the system operator to reclose this line after its initial failure due to the phase angle exceeding stability limits was a direct and decisive underlying cause of the event. 10 minutes were lost in unsuccessful attempts to reclose the line, time which proved crucial given that the resulting overload on the Sils-Soazza line could only be sustained for around 15 minutes.

Subsequent responses by system operators in Switzerland and Italy were considered slow, given the nature of the emergency, and the measures adopted were insufficient to return the system to an N-1 secure state within the 15 minute margin to reduce the overload on the Sils-Soazza line. The UCTE Investigation Committee Final Report also noted the differing accounts of a conversation between the Italian and Swiss system operators, and suggested that ineffective communication and information exchange contributed to an ineffective response. Therefore, although the countermeasures were available to return the system to a secure state, operational, technical and organisational factors prevented a timely and appropriate response.

Table 4

Primary Causes of the Swiss-Italian Blackout

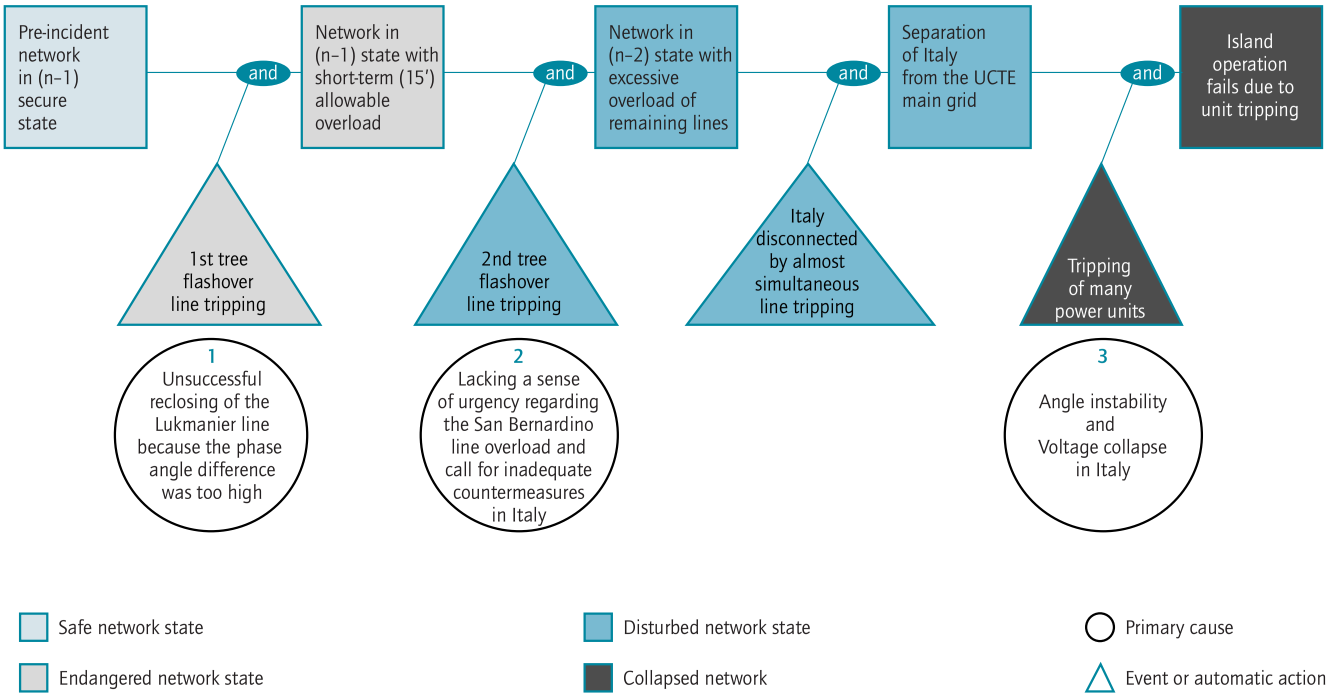
Primary Cause	Impact on Event	Origin of Primary Cause	Action
Unsuccessful re-closing of the Lukmanier line because the phase angle difference was too high	Decisive	Large phase angle due to power flows and network topology	Study settings of concerned protection devices. Reassess possible consequences for net transfer capacity to Italy. Coordination of emergency procedures.
Lacking a sense of urgency regarding the San Bernardino line overload and call for inadequate countermeasures in Italy	Decisive	Human factor	Operator training for emergency procedures. Reassess acceptable overload margins. Study real-time monitoring of transmission line capacities
Angle instability and voltage collapse in Italy	Not an underlying cause of the events but was the reason that island operation of Italy after its disconnection failed.	General tendency towards grid use close to its limits	Further studies necessary on how to integrate stability issues in UCTE security & reliability policy.
Right-of-way maintenance practices	Possible	Operational practices	Perform technical audit if necessary, improve tree cutting practices

Source: UCTE (2004a).

UCTE analysis also indicates that angle and voltage instability occurred in the moments just prior to complete disconnection of the Italian system, resulting in very low voltages in the northern portion of the Italian system at the time of disconnection from the UCTE network. Successful migration to island

Figure 22

Impact of Primary Causes on System Security during the Swiss-Italian Blackout



Source: UCTE (2004a).

operation was very dependent on keeping generating capacity in service, and in the Italian case a necessary condition for achieving this was that voltage and frequency conditions at the moment of disconnection were close to normal. This condition was not met and 21 of 50 large thermal generators were lost during the 2.5 minutes between disconnection and ultimate system failure. According to the UCTE Investigation Committee, the observed instability at the time of disconnection was a primary cause for the failure of the Italian system to operate in an islanded mode.

The UCTE Final Report also suggests that line flashovers that led to key transmission line failures triggering the event may have been caused by insufficient maintenance of easements under transmission lines. This issue was beyond the scope of the UCTE investigation. Hence, a definitive view was not presented. The Swiss Inspectorate for Heavy Current Installations conducted an investigation of this issue and concluded that the network owners involved had undertaken vegetation management in accordance with relevant regulations and standard practise[35].

UCTE Investigating Committee Recommendations

The UCTE Investigating Committee Final Report proposes several recommendations for action at a regional UCTE and national transmission system operator (TSO) level. It also raises several issues in relation to the interface with regulatory arrangements, principally regarding factors affecting system adequacy, especially investments in the transmission system, and the need to strengthen the powers and independence of TSOs to ensure system security.

Recommendations relating to the UCTE-regional level include:

- **Operational Procedures**. For interconnections between UCTE control blocks, confirm, set up or update where necessary the emergency procedures between the involved TSOs. They should be made mandatory and integrated into joint operator training programs. Their performance should be evaluated at regular intervals.
- **Application of the N-1 Criterion**. UCTE's rules in relation to security assessment should seek to:
  - harmonise criteria for compliance with the N-1 principle;
  - determine criteria for the period allowed to return the system to an N-1 secure state after a contingency;

35. Swiss Federal Inspectorate for Heavy Current Installations (2003).

  - include issues such as phase angle and voltage stability in the standard short-term contingency analysis; and
  - define clear guidelines for sharing of tasks to be performed, taking into account the boundaries of each control area.

- **Day Ahead Congestion Forecasts (DACF).** Intensify the ongoing work on DACF in UCTE. In particular increase the frequency of DACF calculations, increase the number of areas involved and provide quality indicators for the data and computed results in order to assess the performance of the forecasts.

- **Real-time Data Exchange**. Extend the existing real-time data exchange among neighbouring TSOs. Data should be consistent so that state estimators can produce more accurate results for a wider area.

- **Technical Specifications for Generating Equipment**. Determine on a UCTE level a set of minimum requirements for generation equipment, defense plans and restoration plans, as a basis for harmonization to be implemented throughout the respective national grid codes and regulations.

- **Emergency Control and Co-ordination of Load Frequency Control**. Further work at the UCTE level is needed to agree on the implementation of appropriate load-frequency control strategies should an accidental split of the synchronous area occur.

- **Improving Wide Area Measurement System (WAMS) Management**. As a support tool for dynamic analysis and monitoring of the UCTE system, accelerate the ongoing WAMS installation program.

Recommendations relating to TSO's at the national level include:

- **Enforcement of Technical Specifications for Generating Equipment**. National Grid Codes (or equivalent regulation) should enforce a set of minimum requirements, to be harmonised at the UCTE level, with respect to the tolerance of generation units to frequency and voltage disturbances.

- **Defense and Restoration Plans**. National regulations should, insofar as they are not yet implemented, provide for: binding defense plans with frequency coordination between load shedding, if any, and generator trip settings; and binding restoration plans with units sufficiently capable of switching to in-house operation and black-start capability. Due consideration should be given to joint simulation, training and evaluation of these plans with all involved parties.

- **Vegetation Management**. Tree trimming practices should be evaluated and the operational results should be audited with respect to the potential line sag under maximum rated overload conditions.

- **Distribution Level Measures**. The blocking of On Load Tap Changers (OLTC) of transformers in case of severe voltage drop should be accepted practice.

Recommendations from the Joint Inquiry by the Italian and French Regulators

Commission de Regulation de l'Energie (CRE – the French Regulator) and Autorita per l'Energia Elettrica e il Gas (AEEG – the Italian Regulator) released a joint report on the event in April 2004[36]. The Report concluded that Swiss operational contingency planning and resources for 28 September 2003 were inadequate and that Swiss system operators lacked sufficient countermeasures to manage a foreseeable event. The Report stated that this lack of preparation contravened UCTE operating procedures and put the whole UCTE system at risk. It also found that inappropriate operational responses exacerbated the emergency and were responsible for the failure of the Sils-Soazza line. Key recommendations included the following.

- The potential for diverging interpretation and application of UCTE operating rules should be eliminated by providing further detail to remove ambiguity.

- Compliance with UCTE rules should be made legally binding.

- The application of UCTE rules should be monitored and enforced by independent bodies formally responsible for verifying TSO compliance. CRE and AEEG suggest that the industry regulators be the responsible body in this context.

- TSO coordination of operational planning and real-time operation of integrated networks should be reinforced.

- A legal and regulatory framework coherent with EU legislation should be implemented and enforced in all European countries operating within the integrated UCTE system to ensure secure network operation and supply in Continental Europe. Switzerland in particular should adopt a compatible framework as a matter of priority.

36. CRE and AEEG (2004).

Recommendations from the Inquiry of the Swiss Federal Office of Energy

The Swiss Federal Office of Energy released its report on the event in November 2003[37]. The report concludes that the underlying causes of this incident lay in "the unresolved conflict between the trading interests of the involved countries and companies, and the technical requirements of the existing trans-national electricity system".[38] Deviations between planned transit volumes and actual volumes represent a threat to system security and should be minimised to the greatest extent possible. Current operational requirements are lagging behind economic realities and need to be addressed. In particular, real-time corrective measures that needed to be undertaken interactively by the system operators in Switzerland, France and Italy could have been implemented more rapidly and coordinated more efficiently. Priority needs to be given to the development and implementation of binding regulation of international electricity trading. Key recommendations included the following.

- Provisions contained in EU Directive 1228/2003 governing network access for cross-border trade need to be implemented in a manner that does not compromise system security. Procedures need to be applied fairly and transparently.
- Swiss authorities should have the right to jointly determine capacity allocations for export to Italy with Italian and French authorities.
- Swiss transmission owners should voluntarily align themselves with the organisational requirements contained in the EU Directives. In particular, they should create an independent TSO as soon as possible.
- Roles and responsibilities of market participants, regulators and market institutions need to be clarified, with binding requirements introduced for:
  - network-related security of supply;
  - allocation of export volumes to Italy;
  - minimum national reserve capacity requirements; and
  - financial compensation for eliminating network congestion.
- Switzerland needs to implement comprehensive electricity market legislation consistent with the EU Directives and to establish a strong electricity sector regulatory authority to ensure:

  – non-discriminatory network access and allocation of transmission capacity;

37. SFOE (2003).
38. SFOE (2003), p21.

  - adequate network investment; and
  - adequate system security.

- Technical regulatory requirements in relation to high voltage transmission line loadings should be reviewed.
- Governmental arrangements for handling power failures should be reviewed. Communication arrangements between network operators and government organisations responsible for energy crisis management should also be reviewed.

CASE STUDY 3: Sweden and Denmark

The Nordic transmission system experienced its worst power failure in 20 years at around 12.37 pm on Tuesday, 23 September 2003. A combination of mechanical faults in southern Sweden occurred in quick succession at around 12.30 pm and 12.35 pm, creating system conditions that were beyond the capacity of normal operational reserves. As a consequence, supplies to southern Sweden and eastern Denmark, including the Danish capital, Copenhagen, were disrupted. The following event summary is largely drawn from the reports prepared by the transmission system operators responsible for the Swedish and eastern Danish networks[39].

Prior to the disturbance, operating conditions were stable and well within the tolerances set in the operational planning and grid security assessment. Contingency planning had taken into account the unavailability of several facilities due to annual or scheduled maintenance. These included nuclear generating units in southern Sweden and several transmission lines, including two 400 kV transmission lines connecting central and southern Sweden, the DC interconnectors between Sweden and continental Europe and the Kontek DC interconnector between Zealand and Germany. Eastern Denmark is closely integrated with Sweden through 400 kV and 132 kV AC submarine cables. Total consumption in eastern Denmark and southern Sweden before the event was around 4 850 MW. Around 400 MW of Swedish demand was being met by exports from eastern Denmark.

At 12.30 pm, Unit 3 at the Oskarshamn nuclear power plant shut down due to mechanical problems with the valves controlling its feedwater circuits. 1 175 MW of generation was lost as a result of the shut-down, and Nordic system frequency began to fall as a result of the production shortfall. This was a standard N-1

39. *See Elkraft System (2003); Svenska Kraftnat (2003) and (2004). Elfrakt System is now part of Energinet.DK.*

contingency event managed through operational reserves. Spinning generating reserves from Norway, northern Sweden and Finland activated automatically to restore the supply-demand balance and to stabilise system frequency. Although power flows increased on the western part of the Swedish transmission system serving loads in southern Sweden, the flows were within pre-determined security limits. After a normal frequency transient the system returned to stable operating conditions in less than a minute without any loss of services. Under the Nordic system security standards, operators have up to 15 minutes to return the system to an N-1 secure state, where it would be able to absorb another similar disturbance without threatening reliable system operations.

At 12.35 pm, a double busbar failure occurred at a 400 kV substation on the west coast of Sweden. This represented a serious system failure consistent with an N-2 event. The fault was caused by mechanical failure of an isolator in one of the busbars, which collapsed in a manner that ignited an electric arc between that busbar and the adjacent busbar. Both busbars were automatically disconnected by protection devices, which immediately tripped the circuit-breakers for all incoming lines to both busbars. This was an extraordinary occurrence.

As a result of this failure, four 400 kV transmission lines were disconnected. Two of these lines provided a key link between central and southern Sweden, while the other two lines each connected a 900 MW nuclear unit at the Ringhals power station to the transmission network. As a result, the transmission path along the west cost of Sweden was lost, as was 1 750 MW of production with the disconnection of the two Ringhals units. However, Ringhals Unit 4 managed to switch to in-house operating mode and was available to support the subsequent restoration.

The sudden loss of generating and transmission capacity triggered large power oscillations, low voltages and a drop in system frequency, initiating automatic under-frequency load shedding. Power flows increased further on the remaining transmission links between central and southern Sweden. Automatic responses from generators in northern Sweden, Norway and Finland to compensate for the loss of the Ringhals units exacerbated these power flows. By this stage, no major generators were left connected to the transmission system in southern Sweden, which substantially reduced the level of reactive power support available for voltage control.

During the 90 seconds following the busbar failures the power oscillations began to fade and the system seemed to stabilise. Load levels began to recover, placing further stress on the remaining 400 kV transmission links between central and southern Sweden. As a result, voltage levels on these lines dropped to critical levels. The situation developed into a voltage collapse in a section of the transmission network southwest of Stockholm. Distance relays on the transmission system in central and southern Sweden registered this event as a distant short circuit, and automatically tripped these transmission lines, severing all remaining transmission connections between northern and southern Sweden. Distance relays for the Oresund interconnectors between Sweden and eastern Denmark did not react as the voltage at the Swedish end of the connection remained relatively high.

An electrical island containing southern Sweden and eastern Denmark formed momentarily. However, the large generation deficit led to a collapse of frequency and voltage over a 1 to 2 second period, triggering generator and network protection devices. The islanded system collapsed at 12.37 pm. Eastern Denmark was automatically disconnected from southern Sweden at the time of the voltage collapse by zero-voltage relay protection devices on the Oresund link. The voltage collapse caused damage to the two largest power stations in eastern Denmark. Damage to the largest of these precluded it from supporting restoration activities after the blackout.

Impact and Restoration

Services in southern Sweden and eastern Denmark were disrupted as a result of the outage. In Sweden, all supplies south of a geographic line between the cities of Norrkoping in the east and Varberg in the west were interrupted, with the exception of some small islands which were being supported by local small hydro power stations that survived the collapse. Figure 23 shows the area affected by the outage.

Around 6 350 MW of load was lost at the time of the outage, around 4 500 MW in Sweden and 1 850 MW in eastern Denmark. Four million people were initially disconnected and the economic cost of the disruption has been estimated at around USD 310 million[40].

In southern Sweden, services were cut to 1.6 million people. Provincial centers were worst affected, along with regional airports and rail services. In eastern Denmark, services were cut to around 2.4 million people. The capital city of Copenhagen was the worst affected area, along with the international airport and rail services.

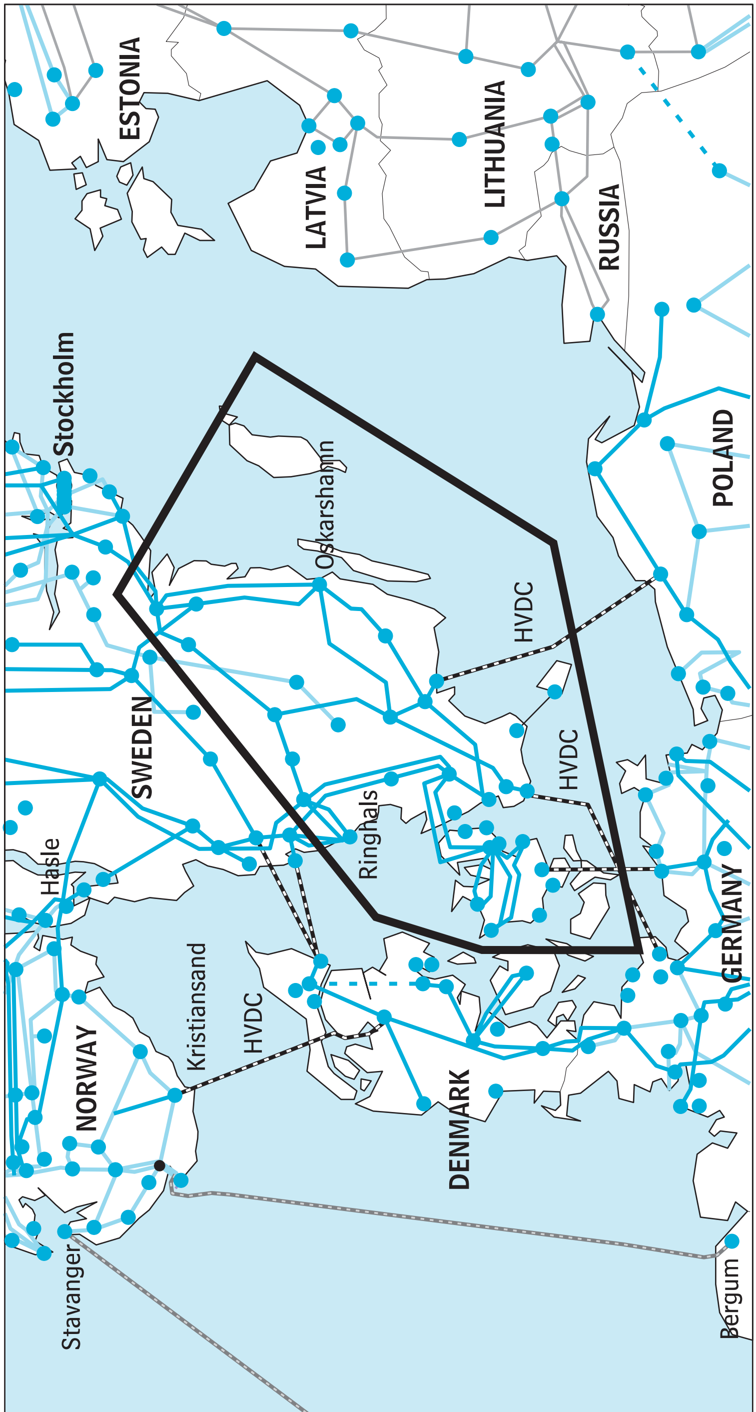
Restoration Process

Restoration of most services in southern Sweden and eastern Denmark was successfully achieved by around 7.00 pm, with full service restoration achieved

40. OXERA (2005).

Figure 23

Area Affected by the Swedish-Danish Blackout, 23 September 2003



Source: Larsson, S. (2004)

in eastern Denmark around 10.00 pm. Some technical difficulties were encountered that slowed restoration to some extent, particularly in eastern Denmark.

In southern Sweden, restoration was facilitated through the northern part of the network, which had remained intact after the separation. Hydropower from Norway, northern Sweden and Finland was used to re-energise the network and to supply load as it was gradually restored in southern Sweden. Transmission lines and substations were re-energised in a manner that allowed the network to be rebuilt from north to south. Restoration proceeded along the eastern and central 400 kV transmission paths from north to south. Technical difficulties with a faulty disconnector at the Horred substation (near the Ringhals power station) slowed network restoration on the western transmission path. Despite these technical difficulties, the main 400 kV network was successfully re-energised down to the southernmost substations within an hour after the initial collapse.

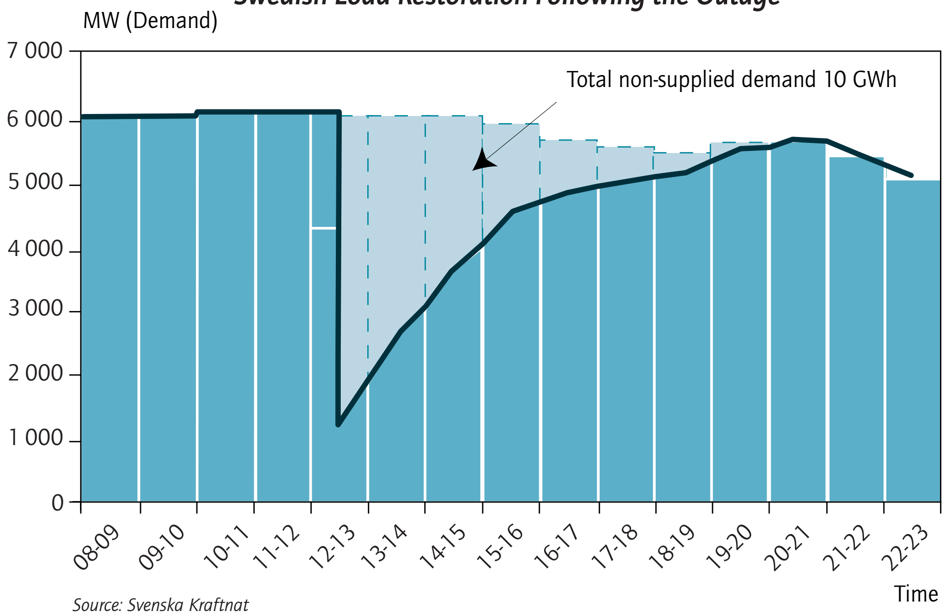
Initial voltages were volatile due to a lack of reactive power before generation was reconnected to the southern network. A serious loss of remote control to a key substation delayed efforts to stabilise voltage and slowed restoration of services. Regional and local network services were restored through feeder transformers connected to the 400 kV network. Initially some restrictions were imposed on restoration of load. However, these were quickly removed as networks returned to service. One of the nuclear units at Ringhals successfully switched to in-house operation during the event and was immediately available to support restoration of load once the network had been restored. Svenska Kraftnat estimates that around 10 GWh of energy was not supplied as a result of the outage. Figure 24 charts the return of load in southern Sweden during the restoration period.

In eastern Denmark, preparations to restore voltage to the main transmission network began within minutes of the outage. All loads were disconnected so that the supply-demand balance could be properly controlled during the restoration. To achieve the quickest possible return of services, the network was prepared for voltage restoration from either the black-start capable generators at the Kyndby power station or through the Oresund interconnection with Sweden. Elkraft System's communications strategy for emergency events was also immediately activated to inform key stakeholders and the public about the event and progress on the restoration.

Restoration of voltage through the interconnection with Sweden was preferred as it would normally be expected to provide the fastest and most reliable solution. It was also the most practical route for timely restoration at the time. Damage to regulating equipment, possibly caused by the voltage collapse

Figure 24

Swedish Load Restoration Following the Outage



Source: Svenska Kraftnat

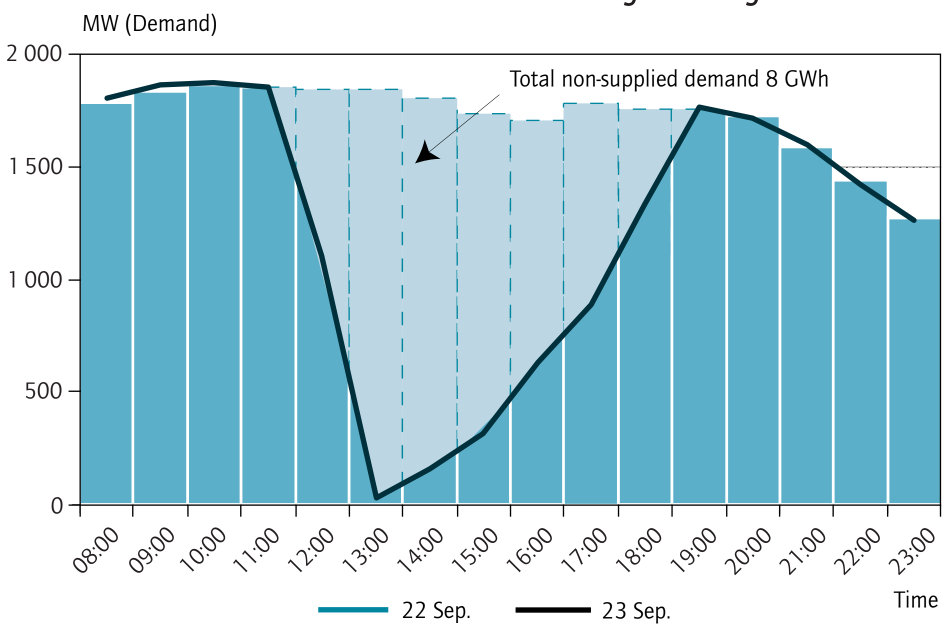
associated with the outage, meant that the diesel plant at Kyndby was unable to affect black-start restoration of voltage to the eastern Danish transmission system.

Svenska Kraftnat had re-energised a 400 kV transmission link to the Swedish end of the Oresund interconnector by 1.30 pm. Voltage had been restored to the transmission system in eastern Denmark through the Oresund link by around 1.45 pm, around 70 minutes after the outage. Initial voltages fluctuated due to a lack of reactive power before generation could be restored to the eastern Danish network. About 200 MW was imported from Sweden to stabilise voltage and provide for initial reconnection of some priority loads.

Restoration of further load followed the reconnection of eastern Danish generators. Load was resupplied in step with the reconnection of major generating facilities, based on a pre-determined 10-part reconnection plan agreed between Elkraft System and local distributors. Restoration of load may have been achieved more quickly had some of east Denmark's large generators successfully switched to in-house operation. Four of ten succeeded temporarily but subsequently failed when the final voltage collapse occurred. Protection systems on generators are usually set to disconnect in response to large frequency or voltage variances. But on this occasion, voltage and frequency conditions developed in a manner that led to the large power stations disconnecting at a relatively late stage in the event, making switching to in-house operation mode more difficult than usual. Elkraft System estimates that around 8 GWh of energy was not supplied as a result of the outage. Figure 25 charts the return of load in eastern Denmark during the restoration period using load from the previous day as a benchmark for comparison.

Figure 25

Danish Load Restoration Following the Outage



Source: Elkraft System.

Key Findings of Investigations and Inquiries

Official investigations of this event were undertaken by Svenska Kraftnat and Elkraft System, the transmission system operators responsible for the Swedish and eastern Danish networks respectively. These investigations were largely undertaken as a joint exercise.

Both reports note that the system was operating in an N-1 secure condition prior to the first fault and that the operational reserves were deployed appropriately to return the system to a stable operating condition. Svenska Kraftnat notes that the underlying cause of the outage was that a second major fault occurred within the 15 minute period allowed under Nordel operating practices for a system operator to return the system to an N-1 secure condition. This second fault shut down two major generators and severely reduced transmission capacity in southern and central Sweden, and occurred only 5 minutes after the first N-1 contingency event. The subsequent disconnection of high voltage transmission lines severely weakened the transmission grid in southern Sweden to an extent that it became impossible to transmit sufficient electricity to meet load.

Elkraft System notes that neither increased production in eastern Denmark nor imports from the continent would have been capable of preventing the subsequent voltage collapse. The combination of these events constituted at least an N-3 contingency event, leading to conditions that were beyond the operational limits of the system and beyond prepared countermeasures. Elkraft System concluded that given the present design of the power system and the current security criteria for system operation and infrastructure protection, it was not possible to prevent the blackout once the second failure had occurred.

Several other key conclusions can be drawn from these investigations. In particular, large disturbances can stem from a sequence of interrelated faults that would be manageable if they appeared alone. Rapid restoration is also extremely important to minimise the adverse impact of outages on modern societies that are highly dependent on electricity supplies. Similarly, the community has a right to be fully informed about outages and progress toward restoration. The provision of timely information to key stakeholders should be a key performance objective for system operators and other entities involved in managing system restoration after an outage.

Key Recommendations

Key recommendations from the investigations included the following.

- **System Operation Practices**. Examine the Planning and Operational Reliability Standards applied within Nordel with a view to assessing whether current technical standards and operational practices are sufficient to deliver reliable electricity services consistent with the efficient operation of electricity markets and community expectations. Modify technical specifications and the Nordic Grid Operation Agreement where appropriate to accommodate new operational conditions.
- **Emergency Procedures**. Consideration should be given to including automatic under-voltage load shedding as a means to manage potential voltage collapse situations, particularly where there is a shortage of

generating capacity. Review protection strategies for generation and network infrastructure to ensure that an appropriate balance is maintained between protecting the infrastructure and maintaining services during emergency situations. Review load-shedding arrangements to ensure that consumer disconnection is appropriately prioritised.

- **Restoration Procedures**. Develop procedures to reduce the time taken to prepare the system for black-start, possibly including establishing relays to automatically disconnect the underlying network in the event of zero voltage. In relation to eastern Denmark, consideration should be given to ways of strengthening restoration, including the potential for using generators operating in in-house mode to provide black-start services and for establishing plants dedicated to voltage restoration. Review reconnection plans to ensure that consumer reconnection is appropriately prioritised.

- **Emergency Operation of Generation**. Mandatory technical requirements are to be enforced, particularly in relation to managing the transition to in-house operation following external network disturbances.

- **Tools and Protection Devices**. Examine the potential for more advanced measurement and control systems in which information on system conditions from several control areas can be integrated. Such systems are not yet fully developed and their implementation would require an integrated evaluation of the design and system operation strategy for the Nordic synchronous area in order to avoid unplanned disconnections. Consider developing more advanced protection systems, possibly including the potential to detect voltage collapse in the entire system as part of a more integrated strategy for system operation. Investigate the potential to improve remote control functionalities under outage and transient conditions.

- **Communication**. Communication strategies should be reviewed and adjusted in the light of this experience, to strengthen timely flow of information to distributors, consumers, authorities and the media as appropriate.

- **Physical Design and Maintenance of the Transmission System**. The second fault focuses general attention on the design, inspection and preventative maintenance of the transmission system, particularly at vulnerable points with substantial consequences for reliable system operation. Specific issues include:
  - examination of the potential for restructuring switching gear at substations to eliminate the risk of flashovers between main busbars;
  - mandatory inspections of disconnectors and scheduled replacement of critical parts; and

- review of the methodology and resources applied to manage outsourced maintenance.

- **Investment**. Consider the potential for upgrading transmission lines to help improve system reliability. Proceed to reinforce transmission capacity to southern Sweden. New generation being constructed in southern Sweden will help to improve reliability within the region.

CASE STUDY 4: Australian National Electricity Market

On Friday, 13 August 2004, a current transformer at the Bayswater Power Station in New South Wales developed an internal fault causing it to later explode. This failure triggered a major power disturbance in the Australian National Electricity Market. Five large generating units and a medium generating unit were lost in New South Wales within 25 seconds. Although emergency responses led to the disruption of power supplies in the states of New South Wales, Victoria, Queensland and South Australia, a complete disruption of services was avoided. The following event summary is drawn from the reports prepared by the National Electricity Market Management Company (NEMMCO), which is the independent market and system operator responsible for the Australian National Electricity Market[41].

At 9.41 pm, a current transformer in the number 1 bay at the Bayswater Power Station switchyard (New South Wales) failed and later exploded. The switchyard has three 330 kV circuit breakers connecting the number 1 generating unit of the Bayswater Power Station and a transmission line (34 Line) to the Liddell Power Station. The current transformer fault was detected by protection devices, which activated 34 Line circuit breakers at the Liddell and Bayswater power stations, isolating the fault from the power system.

The great majority of faults that trip transmission lines are transient in nature with a relatively short duration. As a result, transmission line protection systems usually incorporate auto-re-close facilities so that the transmission network can be fully restored as soon as possible after such events.

Fifteen seconds after the initial fault, the auto-re-close function operated as designed to automatically re-close the main bus circuit breaker on 34 Line. However, the fault on the current transformer remained, and resulted in the fault effectively being reapplied to the power system when 34 Line's

41. NEMMCO (2004); (2005a) and (2005b).

protection system automatically re-opened the circuit breaker. But on this occasion generator differential protection on Units 1, 2 and 3 at the Bayswater Power Station also tripped, resulting in the immediate loss of 1 971 MW. Negative phase sequence protection also activated the automatic shutdown sequence for Unit 2 at the Eraring Power Station, ultimately resulting in the loss of a further 424 MW.

Sixteen seconds after the initial fault, the auto-re-close function on 34 Line operated again, this time to attempt an auto-re-close of the coupler circuit breaker. However, the current transformer fault was still present and the subsequent auto-re-close procedure effectively applied the fault to the power system for a third time. Twelve seconds later automatic voltage regulator protection tripped Unit 6 at the Vales Point Power Station, resulting in the loss of a further 542 MW. One second later Unit 2 at the Eraring Power Station completed its shutdown sequence and the unit was automatically disconnected from the power system.

Around 36 seconds after the initial fault, under-frequency protection activated automatically to trip the Redbank Power Station, resulting in a further loss of 150 MW.

Impact and Restoration

Within 40 seconds of the original fault, six generating units had been disconnected in New South Wales, resulting in the loss of around 3 100 MW, representing around 14% of total supply to the National Electricity Market.

The sudden loss of generation caused a substantial frequency disturbance on the power system. Frequency had fallen to near 49.0 Hz around 6.5 seconds after the initial power plant trips. Emergency under-frequency load shedding in New South Wales, Queensland, Victoria and South Australia combined with frequency control ancillary services (FCAS) procured by NEMMCO from the FCAS market stabilised the situation. However, the subsequent tripping of the Vales Point Power Station resulted in frequency again falling below 49.0 Hz. Available FCAS reserves had been exhausted by that stage, resulting in further emergency under-frequency load shedding in New South Wales, Victoria and Queensland to stabilise frequency.

Table 5 shows the distribution of emergency under-frequency load shedding across the National Electricity Market. Over 1 500 MW of load was disconnected as a result of automatic under-frequency load shedding, representing nearly 7% of total demand. Queensland bore the brunt of the impact, losing around 9.5% of regional demand. Victoria also lost significant load, representing around 8% of regional demand. However, the impact in Queensland was worsened by the nature of the pre-determined load shedding schedule, which led to the early disconnection of around 250 000 residential consumers. Load shedding arrangements in the other affected states tended to favour the early disconnection of industrial loads and hence minimised the impact on residential consumers.

Table 5

Automatic Under-frequency Load Shedding by Region

Region	Demand (MW)	Load shed (MW)	As % of demand
New South Wales	9 208	462	5.0
Victoria	5 998	488	8.1
Queensland	5 726	542	9.5
South Australia	1 669	18	1.1
Snowy	28	0	0.0
NEM Total	**22 629**	**1 535**	**6.8**

Source: NEMMCO.

The remaining 1 600 MW power deficit was met through a combination of increased generation, low frequency load relief (via FCAS) and other customer disconnections due largely to related voltage disturbances. In New South Wales these latter load losses totalled a further 342 MW, bringing the total lost load in New South Wales to around 800 MW or 8.7% of regional demand.

Immediately after the loss of generation in New South Wales all interconnector transfers into the State increased substantially as reserves were called upon to stabilise the system. Generation reserves from Victoria, Queensland and the Snowy region all contributed to restore the balance. Table 6 shows inter-regional flows just prior to the incident and the change in inter-regional flows following the disturbance.

Power transfers on the QNI interconnector from Queensland to New South Wales exceeded operational security limits by up to 25% following the disturbance, but were reduced below the security limit after around 15 minutes, well within the 30 minute maximum period established in the

Table 6

Inter-regional Power Flows Following the Disturbance

Interconnector	Initial (MW)	Maximum (MW)	After 10 Minutes (MW)	Approximate Line Limits (MW)
QNI to NSW (AC)	213	1 188	1 040	905
Directlink to NSW	0	0	0	N.A.
Snowy to NSW	-15	1 313	1 313	3 000
VIC to Snowy	-100	905	660	760
SA to VIC (AC)	-460	-241	-460	-460
Murraylink to VIC	-80	-3	-3	N.A.

Source: NEMMCO.

National Electricity Code for reducing transmission line overloads. Similarly, power transfers from Victoria to the Snowy region exceeded security limits by up to 20%, but were reduced below the security limit within 4 minutes.

NEMMCO had purchased sufficient FCAS to ensure that frequency levels consistent with operating standards could be maintained in the event of a single credible contingency (ie. an N-1 event). This disturbance, however, represented a multiple contingency event. Under current operational practises, NEMMCO does not purchase sufficient FCAS in advance to cater for multiple contingencies given the low probability of their occurrence and the likely considerable additional cost. However, given the emergency, NEMMCO called on all enabled service providers to supply the maximum possible amount of FCAS. Table 7 summarises FCAS service providers' performance in response to the emergency during the 5-minute dispatch interval commencing at 9.40 pm.

Table 7 shows that services delivered were well above the services enabled for the period. Fast response (6 second) raise FCAS provided was over twice the level enabled for the period, while 1 minute raise FCAS provided was over 7 times the levels enabled and 5 minute raise FCAS provided was nearly 2.5 times the levels enabled. Automatic generator governor responses to the frequency drop accounted for a large proportion of the FCAS response. The FCAS response together with the low frequency load relief supported the under-frequency load shedding in containing, stabilising and restoring power system frequency.

Table 7

FCAS Service Delivery During the Event

	Fast (6 Second) Raise (MW)		Slow (60 Second) Raise (MW)		Delayed (5 Minute) Raise (MW)	
	Delivered	Enabled	Delivered	Enabled	Delivered	Enabled
NSW	268	69-	531	67	225	90
VIC	69	95	183	80	181	118
QLD	146	75	641	92	206	119
SA	124	36	195	15	27	30
Snowy	5	0	294	0	281	120
Total	**612**	**275**	**1 844**	**2 540**	**920**	**477**

Source: NEMMCO.

Media and community interest focused on Queensland given the impact of load shedding on residential consumers in that state. NEMMCO acted quickly to provide information to key stakeholders and the media. Under the National Electricity Market Emergency Protocol, NEMMCO was also required to inform representatives of member governments. There were some delays in contacting certain officials but NEMMCO notes that these delays did not affect management of the disturbance or delay service restoration.

Restoration Process

A secure operating state was achieved when frequency was stabilised within the normal operating range at around 9.47 pm, some 6 minutes after the disturbance. At 9.56 pm, all affected loads were restored in South Australia, around 15 minutes after the outage. 50 MW of load was restored in Queensland at 10.02 pm. Two small 'sensitive loads' were also restored in New South Wales around this time. Two loads were restored in Victoria at 10.04 pm. Another 50 MW of load was restored in Queensland at 10.05 pm, followed by a further 100 MW at 10.28 pm. At 10.35 pm NEMMCO issued instructions to restore all remaining affected load in Queensland at a rate of 100 MW every 5 minutes.

By 10.20 pm, around 40 minutes after the outage, services to all affected load in New South Wales and Victoria had been restored, while most affected services were restored in Queensland by 11.00 pm, around 80 minutes after the outage. NEMMCO estimates that a little over 1 GWh of energy was not supplied as a result of the disturbance.

All but one of the affected generating units in New South Wales returned to service within 24 hours, with the remaining unit returning to service around 44 hours after the incident.

Key Findings of Investigations and Inquiries

NEMMCO undertook the official investigation of this event drawing on information provided by market participants and transmission network service providers.

The primary cause of the event was the failure of a current transformer at the Bayswater Power Station switchyard. Other recent current transformer failures led the transmission owner to install monitoring devices on all similar equipment to provide an early warning of a potential failure. However, the 13 August fault was qualitatively different to the faults previously experienced. The monitoring device was not designed to register this kind of fault, and therefore did not provide any warning of the approaching failure.

NEMMCO's analysis also suggests that a combination of technical failures may have magnified the impact and duration of the event. In particular, protection devices installed at some of the disconnected generators did not appear to operate as intended. For instance, the Bayswater units 1-3 were tripped by differential protection relays, which are intended to detect faults within generating equipment. However, these relays activated even though the current transformer fault was well outside the differential protection relay zone for these units. Similarly, the Eraring Unit 2 was tripped by its negative phase sequence protection systems, which are normally only meant to activate as a last resort response to external uncleared faults that may damage the generating equipment. On this occasion, the time delay function did not operate correctly and the unit was shut down as soon as the fault was detected. Problems with the power system stabilisers at the Vales Point Power Station may also have contributed to faulty operation of its automatic excitation regulator, leading to its shut-down. The Vales Point trip, which initiated the second dip in system frequency, was important in this context given NEMMCO's conclusion that this second frequency fall significantly delayed eventual recovery of frequency and restoration of services.

NEMMCO concluded that the emergency automatic under-frequency load shedding response performed according to design and in conjunction with FCAS operated effectively to stabilise power system frequency within the limits and timeframes established by operating standards, avoiding a catastrophic system collapse. However, some automatic under-frequency load shedding, which should have occurred, did not. Also, the impact of the load shedding may have been more equitably distributed among the regions. This latter issue was the cause of some concern, particularly in Queensland, which bore the brunt of the disturbance. Potential to rebalance load shedding is being investigated, but as NEMMCO notes, it may not be possible to ensure equal sharing between jurisdictions within an integrated regional market for every possible contingency, especially in the case of multiple contingency events.

Several other key conclusions can be drawn from NEMMCO's investigation. Successful management of such a major failure provides a practical example of the benefits for system security resulting from regional integration. Integration helped to strengthen the resilience of the power system in response to emergency conditions. In this case, the system operator had the authority and capability to draw on inter-regional resources in real-time to efficiently stabilise and restore secure operating conditions, which helped to minimise the impact of the event. It demonstrates the value of having a system operator with sufficient authority and scope to prepare operational contingency plans and execute them in real time on a whole-of-market basis in response to emergency situations.

The event also revealed potential system security issues associated with load flows on interconnectors. The National Electricity Market (NEM) is built around a largely radial (ie. point to point) bulk transmission system. As a result, key transmission line failures, particularly at points of interconnection between NEM regions, have the potential to immediately isolate regions and magnify the impact of any emergency event within an isolated region. NEMMCO's analysis suggests that a further generator failure could have tripped the QNI interconnector leading to effective separation of Queensland from the NEM, and potentially exacerbating the impact of the event in Queensland. Temporary overloading of transmission lines occurred as a result of the emergency response, and is to be expected following a multiple contingency disturbance of the kind experienced. The event has raised questions about how to strengthen the resilience of interconnectors and other key transmission lines so that they can support emergency responses and restoration activities to the greatest extent possible.

Key Recommendations

Recommendations from NEMMCO's investigation included the following.

- **Operational Standards**. National Electricity Code provisions relating to automatic re-closure, generating unit technical standards and incident investigation should be urgently reviewed, as follows:

  - The role of automatic re-closure in relation to power system security and the obligations on network service providers and generators should be reviewed to ensure that generating units are required to withstand faults reapplied by re-closure in the network.
  - Generators required to provide information to NEMMCO to support its investigation of a system disturbance should be required to report to NEMMCO within a reasonable timeframe, 20 business days for example.

- **Emergency Procedures**. The under-frequency load shedding arrangements across the National Electricity Market should be reviewed. (NEMMCO has initiated a review of the under-frequency load shedding arrangements.)
- **Generator Protection Relays**. Macquarie Generation and Delta Electricity should complete their investigations into the reasons why their respective generating units tripped, and provide NEMMCO with:
  - details of the conclusions in their reports;
  - assurances that their generating units can withstand disturbances following credible contingency events that are cleared in primary protection time and with subsequent auto-reclosure onto a fault; and
  - Redbank Project Pty Ltd. should amend its under-frequency tripping settings as soon as practicable and provide NEMMCO with an assurance that their generating unit can withstand frequency disturbances within the limits of the frequency operating standards.
- **Communication**. NEMMCO should review and improve the arrangements for responsible officer (ie. key government contact point) communications following major system incidents.

POLICIES TO STRENGTHEN TRANSMISSION SYSTEM SECURITY

Electricity market reform has fundamentally changed the environment for maintaining reliable and secure power supplies. Growing inter-regional trade has placed new demands on transmission systems, creating a more integrated and dynamic network environment with new real-time challenges for reliable and secure transmission system operation. These operational challenges are intensified as transmission capacity is absorbed.

Although it would be impossible to cost-effectively eliminate the risk of future blackouts, the case studies demonstrate that opportunities exist to improve the resilience of transmission systems and the flexibility of system operation in response to disturbances and emergency events.

Management of system security needs to be transformed to maintain reliable electricity services in this changed operating environment. Clearly defined responsibilities and authority to act are required. Improved operating practices, with greater emphasis on system-wide preparation, and co-ordination to support flexible, integrated real-time system management are also needed. Effective real-time system operation requires accurate and timely information and state-of-the-art technology to facilitate effective contingency planning, system monitoring, flow management and co-ordinated emergency response. The case studies highlight these issues and demonstrate the potentially substantial cost of failure to adequately address them.

These challenges raise fundamental issues for policymakers. Scope exists to clarify responsibilities and accountabilities, and to improve enforcement in this context. Rules and practices governing transmission system security can also be enhanced. New and existing technology could be more fully employed to enhance effective system operation. Asset and vegetation management could be strengthened, while co-ordination, particularly within integrated transmission systems spanning multiple control areas, could be improved.

Inadequate responses to these issues have the potential to encourage overly conservative management of transmission capacity at the expense of efficient inter-regional trade, or to potentially leave interconnected networks unduly exposed to the risk of further substantial power failures.

Strengthening Transmission System Security Incentives

Effective incentives are required to ensure transmission system security in competitive electricity markets. Incentives must reflect the key characteristics that affect transmission system security. In particular, maintaining system security requires a coordinated effort through the value chain and across integrated electricity systems spanning multiple control areas. A breakdown of coordination can lead to imbalances that can push the transmission system beyond its reliability limits, magnifying the risk of disturbances and rapidly cascading system failures. Incentive structures must also have regard for the implications arising from system operators being responsible for making operational decisions about system security but not being directly exposed to the consequences of those decisions[42].

Transmission system security also exhibits certain public good characteristics. Although transmission system security is of value to all system users, it is not readily possible to define an exclusive property right for it. As a result, system security is a good that can be consumed by any network user irrespective of their willingness to pay, which creates incentives to use the good and rely on others to pay for it – the 'free rider' problem. This could lead to insufficient provision for transmission system security where responsibilities and accountabilities are poorly defined[43].

Successful incentive structures are built on sound governance principles. In general, sound governance aims to establish clear responsibilities that are aligned with the role and function of each party so that those parties best able to manage a risk or function at least cost have the authority, means and incentive to act, and are held accountable for their actions. All parties whose actions may significantly affect transmission system security should be involved including governments, regulators, system operators, transmission owners, electricity users and generators. Appropriate and inclusive governance arrangements create the foundation for developing a mutually reinforcing web of incentives and accountabilities for maintaining transmission system security.

Before electricity liberalisation, industry structure provided the key foundation for effective governance. Each system operator was part of a vertically integrated electricity utility. Within its local control area, each operator had complete authority to co-ordinate and control electricity production and flows to

42. *Kirby, B. and Hirst, E. (2002).*
43. *IEA (2003).*

meet demand while maintaining transmission system security. Flows between control areas were relatively minor and closely controlled. Excess network and generation capacity also assisted system operators in maintaining system security. In this environment, responsibility and accountability for maintaining transmission system security could be clearly and readily allocated to local utilities as their functions and the scope of their activities provided them with the means to effectively co-ordinate the value chain to deliver system security.

Reliability standards and regulatory arrangements were built upon the governance foundation created by the vertically integrated industry structure. Standards were typically developed and approved by industry bodies, or developed by industry bodies and approved by technical regulators. Application of standards was often voluntary, and enforcement was in some cases largely left to the industry and peer or public pressure. Regulatory requirements were often defined in very general terms such as the obligation to supply or an obligation to provide a reliable service.

In a vertically integrated environment the costs associated with system operator actions to deliver system security were almost always hidden and averaged, with cost plus regulatory regimes typically permitting all such costs to be opaquely passed through to end users. Co-ordination across control areas was less problematic in this less competitive environment, which was more conducive to inter-regional cooperation. Hence, the need for external, independent regulation, clear and legally enforceable standards and greater transparency to strengthen incentives for maintaining transmission system security was less apparent.

Electricity market reform has fundamentally altered the underlying drivers for sound governance and weakened previous arrangements for maintaining effective transmission system security.

In particular, unbundling and independent, decentralised decision-making in response to competitive commercial incentives has greatly reduced system operators' capacity to co-ordinate and control production and electricity flows throughout the value chain. At the same time, system management practices are receiving greater scrutiny from market participants whose commercial interests are now directly affected by any interventions to manage reliability and system security. These commercial interests, arising as a result of electricity reform, raise questions about transparency, objectivity and legal liability associated with system operation.

Independent, decentralised decision-making has created a much more dynamic real-time operating environment, while the concurrent growth of electricity trade across integrated control areas has exposed local system operators to a degree of systemic risk not previously experienced. Together these new patterns of network use have greatly complicated the task of maintaining transmission system security, especially in real-time and across integrated control areas. This would imply a greater need for co-ordination and cooperation to successfully manage system security in more dynamic and integrated electricity markets. However, the combination of these factors may have in effect weakened incentives for co-ordination and information exchange between system operators, particularly where they remain within vertically integrated utilities that are competing in regional wholesale markets.

Functions previously concentrated within vertically integrated utilities are now spread among system operators, generators and users, while the emergence of more integrated regional electricity markets has seen a horizontal spreading of functional responsibility for transmission system security across multiple control areas.

Governance arrangements need to accommodate these fundamental structural and market changes. Opportunities exist to improve the governance framework in ways that will help to strengthen transmission system security in a manner that is consistent with the emergence of efficient electricity markets, and which provides scope for flexible evolution of standards and practices to accommodate new technologies and market developments. An effective framework should:

- clarify individual and shared responsibilities for transmission system security;
- align accountabilities with the new functional responsibilities resulting from unbundling;
- ensure the boundaries of authority to act are specified for each party, and that parties have sufficient authority to undertake their responsibilities within those boundaries;
- provide strong incentives for effective co-ordination and information exchange, within the value chain and across systems spanning multiple control areas, reflecting the shared nature of responsibility for aspects of transmission system security;
- create transparency and objectivity, given the potential commercial implications of system operators' actions in competitive electricity markets;
- strengthen coverage, accountability and enforcement, where necessary, to help reinforce incentives for providing appropriate levels of transmission system security, and to build the credibility of the regime;

- be applied consistently across an intergrated transmission system; and
- balance market requirements for access to transmission capacity with transmission system security requirements.

Addressing these challenges raises policy issues in relation to the legal, regulatory and structural framework. It also raises questions about the nature, development and application of security standards and operating practices employed to maintain transmission system security in competitive electricity markets.

Legal, Regulatory and Structural Framework

Effective legal and regulatory regimes provide an essential foundation for establishing an effective governance and incentive structure for ensuring transmission system security in competitive electricity markets. Ideally, the legal and regulatory regime should clearly identify the responsibilities and accountabilities of the various parties affecting transmission system security and provide a means to codify those responsibilities and accountabilities. Legal and regulatory regimes should also clearly delineate the nature and scope of authority each stakeholder has to discharge their responsibility. They also need to provide an effective mechanism for enforcement, especially where other incentives for appropriate action may be relatively weak.

Legal and regulatory arrangements could be expected to emerge as the principal means for establishing effective governance and incentive structures for transmission system security in competitive markets, replacing previous substantial reliance on the vertically integrated local utility structure. However, there may be a transitional 'vacuum' while these arrangements are being developed and implemented. During this period there is a risk that responsibilities and accountabilities may remain poorly defined or default to system operators who may no longer have sufficient authority to effectively manage them.

The case studies highlight several examples of such uncertainty and poorly defined responsibilities. For instance, concerns about this uncertainty were raised by the UCTE in the context of its investigation of the Swiss-Italian blackout. UCTE notes that uncertainty regarding the role and authority of transmission system operators (TSOs) to act, particularly in emergency situations, needs to be removed. Legal and regulatory clarity is required to define the boundaries of TSO responsibilities and accountabilities so that they can be empowered to effectively manage system security[44].

44. UCTE (2004a).

Another dimension of this uncertainty was raised in the Swedish-Danish and Australian case studies. Both cases suggest that poorly defined obligations on generators to ensure that plants could withstand credible contingencies may have contributed to their failure to meet specified performance requirements[45].

These examples highlight the importance of clarifying roles, responsibilities and accountabilities within a legal and regulatory framework enabling effective enforcement, and the need to remove or minimise any related uncertainties as quickly as possible.

Several legal and regulatory approaches have been employed in competitive electricity markets to create accountability and to provide a basis for enforcement.

Legal instruments, including legally enforceable codes that specify responsibilities and accountabilities in relation to transmission system security, have been adopted in the United Kingdom and by jurisdictions participating in the Australian National Electricity Market. In the United Kingdom, code requirements have been augmented with specific transmission system operator licensing agreements incorporating a more precise interpretation of the requirements for reliability and system security[46]. In the United States, the recently enacted Electricity Modernisation Act 2005 provides the legal basis for the creation of an independent regulatory framework to define, monitor and enforce transmission system security standards[47].

A mandatory system of reliability standards has also applied in Ontario since market opening in 2002. Under this arrangement, the Independent Electricity System Operator (IESO) has statutory authority to maintain the reliability of the IESO-controlled grid in accordance with NERC reliability standards. The electricity market rules reference the Northeast Power Coordinating Council (NPCC - the regional reliability coordinator) reliability requirements and require market participants to meet these requirements through compliance with the market rules. The IESO assesses and enforces compliance with these reliability provisions and can restrict participation or impose financial penalties on market participants. The NPCC monitors compliance by the IESO and can sanction the IESO. The regulator, the Ontario Energy Board, acts as an appeal body to these compliance and enforcement decisions.

A System Operator Agreement has been implemented by the Nordel transmission system operators[48]. This agreement addresses issues of shared

45. NEMMCO (2005a) and Elkraft System (2003).

46. See National Grid Transco (2004) and (2005) for details.

47. United States Congress (2005).

48. Nordel (2004a).

responsibility in relation to managing reliability and system security within the Nordic electricity market. It is designed, among other things, to facilitate effective co-operation and information exchange on matters affecting joint system security. It incorporates agreed standards for system security, agreed principles for managing operational disturbances and agreed procedures for procuring operating reserves through a market-based process. Although the agreement is considered binding by member transmission system operators, it does not appear to be legally enforceable. Nordic governments separately prescribe certain system security requirements and emergency responses, which are enforceable through national legislation.

Contractual mechanisms have also been employed to ensure accountability and compliance. UCTE has recently implemented a multilateral agreement to make the system security and reliability standards contained in the UCTE Operation Handbook legally binding for all member transmission system operators in continental Europe. The multilateral agreement entered into force on 1 July 2005[49]. A key objective of the multilateral mechanism is to help clarify system operator responsibilities and to provide a legal framework for undertaking system operation functions. The mechanism also incorporates sufficient flexibility to permit ongoing evolution of the underlying standards without invalidating the agreement.

In North America, the Western Systems Co-ordinating Council has employed a Reliability Criteria Agreement with independent power producers and transmission service providers to enforce reliability requirements in restructured electricity markets. This agreement is similar to a bilateral contract that specifies compliance requirements for system operators in relation to operating reserves, disturbance control, control performance and operating transfer capability. Penalties for violation range from a letter to the chief executive through to fines of USD 10 000 or USD 10/MWh, whichever is higher, and include an increasing contingency reserve penalty for a three-month period following any violation of the disturbance control criteria. Although coverage is voluntary, initial results suggested that there had been an improvement in compliance with reliability criteria following its introduction[50].

NERC has also sought to enhance its compliance audit program following the 2003 blackout and to increase peer and public pressure for compliance by posting the names of violators on its website. The recently enacted legislation will substantially strengthen the effectiveness of the compliance auditing program by providing an effective means of ensuring compliance and enforcement[51].

49. UCTE (2005a).

50. Kirby, B. and Hirst, E. (2002).

51. NERC (2005b).

Several challenges associated with clarifying responsibility, compliance and enforcement of transmission system security may arise. Opportunities clearly exist to move toward more comprehensive coverage and enforcement, and efforts are being made to do so.

One significant challenge relates to defining responsibilities and accountabilities. For instance, precise clarification of roles, responsibilities and accountabilities may prove a considerable practical challenge in this context, especially where the boundaries of responsibility may be overlapping and somewhat ambiguous. This could occur, for instance, at the interface between control areas in the context of managing parallel flows, or at the interface between an independent system operator and transmission owners in the context of managing network control ancillary services.

The European Union has sought to address this issue in its draft security of supply directive. Article 4 of the draft directive envisages that transmission system operators would be largely responsible for ensuring transmission system security, subject to performance standards endorsed by a member state or an appropriate national regulator[52]. However, assigning responsibility and accountability for 'operational reliability' largely to TSO's may prove problematic in practice. As discussed previously, unbundling and decentralised decision-making has created a new operational environment where system security is essentially a responsibility shared across the value chain and among all TSO's within an integrated transmission system. Inappropriate allocation of responsibility in this context has the potential to distort system operator behaviour, with the potential to produce overly conservative management of transmission systems at the expense of efficient interregional trade, or to encourage actions that may weaken overall system security. Member states will face the challenge of precisely specifying these responsibilities and accountabilities.

Management of shared responsibilities that cannot be readily allocated to individual stakeholders will require the development of innovative legal and regulatory approaches.

Prior to the recently enacted Energy Policy Act in the United States, NERC had begun to address this challenge through the development of a functional model. The model identifies 17 basic functions associated with operating a transmission system, and with maintaining power system reliability. It aims to provide a means for identifying key functions and assigning responsibilities for performing each function, irrespective of the institutional framework applied. It also identifies the

52. *European Parliament (2005).*

key tasks and minimum capabilities each responsible entity should have to undertake each function, and the interaction between functions both in terms of the inputs needed from other functions to undertake a particular function and in terms of the other functions that are directly affected by the performance of each function. Responsibilities can be combined under this model, however, they cannot be split between different responsible entities. A single responsible entity would remain accountable for undertaking all tasks within a functional responsibility, including any tasks assigned to other parties. In this way accountabilities would remain clearly and precisely allocated between all responsible entities. Key features of the functional model are presented in Annex 2.

The model has received cautious support from the industry and is undergoing further development and evaluation. It clearly illustrates the complex interdependence between functions, reflecting the shared nature of responsibility for key elements of transmission system security and reliable delivery of electricity services in general. It also highlights the challenge associated with defining functional responsibilities and assigning accountabilities to create incentives for effective, coordinated management of all aspects of reliability in reformed electricity markets. Meeting this challenge requires a sophisticated response. The NERC proposal represents a positive a step in this direction.

Care also needs to be exercised in relation to defining obligations in the context of establishing performance contracts for transmission system security. For instance, during the early phase of the merchant power plant development in North America, some system operators entered into ancillary services contracts with independent power producers (IPPs) that failed to explicitly account for certain services like reactive power for voltage control. IPPs that signed these contracts had no guarantee of payment for these services, and reportedly balked at providing them. Similar lack of incentives to provide ancillary services may exist in competitive markets where these services can only be provided at the expense of producing active power for sale on wholesale markets.[53]

Common definitions of responsibility for system security may also prove to be a challenge across integrated networks spanning multiple jurisdictions and control areas. A recent Nordel report to Nordic energy ministers noted that regulations defining system security responsibilities vary across the Nordic market and recommended that a common definition be developed with legislation and regulations across the Nordic market harmonised accordingly[54]. A similar argument can be made in favour of implementing

53. Kirby, B. and Hirst, E. (2002); Bialek, J. (2004).

54. Nordel (2005a).

consistent rules for system security across control areas within integrated regional transmission systems[55].

Mechanisms designed to uphold legal rights, enforce accountabilities, resolve disputes and determine compensation for damages need to be credible – in other words, they need to be consistent, objective and transparent. The challenge here, given the likely technical nature of any dispute, is to create a credible and timely process that produces fair and binding rulings. Standard legal procedures would achieve binding rulings, but may not have access to sufficient technical expertise to enable effective adjudication in a timely manner. Conciliation or arbitration processes could be established to address technical expertise and timeliness, but may not have sufficient legal standing to deliver binding rulings. Questions may also be raised over the independence of conciliation or arbitration processes, depending on how they are constituted. Issues surrounding the determination of compensation in the event of damages may also prove problematic given the shared nature of the responsibility for many aspects of transmission system security. UCTE is in the process of developing a conciliation process in the context of its multilateral agreement[56].

Exposure to legal liability has the potential to strengthen incentives on system operators to effectively manage transmission system security. However, caution needs to be exercised. The shared nature of responsibility for certain aspects of transmission system security may make application of legal liability problematic. For instance, individual responsibility and liability for the events described in the case studies would be impossible to determine objectively.

Full exposure is intuitively appealing as it has the potential to maximise system operator incentives to effectively manage transmission system security. However, it may also encourage behavior that is not conducive to efficient system operation or to effectively managing system security. For example, a system operator that is fully exposed to liability for system security failures would be encouraged to adopt very conservative operating practices that may be inconsistent with promoting efficient trade and market development.

Full exposure to legal liability may also discourage transparency and information exchange, which could serve to reduce transmission system security and the quality of co-ordinated responses to manage disturbances in integrated transmission systems spanning multiple control areas. It may also discourage efficient use of operational tools to manage emergency events. Uncertainty regarding legal liability was cited to help explain the reluctance

55. Alvarado, F. and Oren, S. (2002).

56. Vandenberghe, F. (2004).

of system operators to employ load shedding to help manage the 14 August 2003 blackout in North America. The US-Canada Power System Outage Task Force Final Report indicates that effective application of 1 500 MW load shedding in Ohio could have prevented the disturbance from cascading and ultimately disconnecting over 60 000 MW[57].

Conversely, a complete liability exemption could substantially weaken incentives for system operators to effectively manage transmission system security, and possibly even encourage less-than-prudent operational behaviour. A balance needs to be struck to ensure that exposure to legal liability provides appropriate incentives for transparency, information exchange and prudent management of system security. Limited liability arrangements established on an *ex ante* basis may provide a practical approach in this context.

Regulatory Arrangements

Effective regulatory arrangements are essential for monitoring and enforcing compliance with transmission system security standards in restructured electricity markets. They provide a practical institutional framework for reinforcing responsibilities and accountability, and for applying regulatory discretion and judgment to resolve remaining uncertainty.

In an unbundled environment, effective regulatory arrangements have the potential to assure competing market participants that system operators' decisions in relation to transmission system security are objective, non-discriminatory and comply with security standards. This is important given that: system operation is a natural monopoly, system operators are largely separated from the financial consequences of their system security decisions, and these decisions can have substantial commercial consequences for competing market participants. Management of transmission system security has implications for electricity trade and market efficiency.

Ideally, regulatory arrangements should be independent, with regulatory processes characterized by transparency, objectivity and consistency. Such arrangements have the potential to ensure effective monitoring, compliance and enforcement of transmission system security standards, while building credibility and confidence in the regulatory framework among stakeholders.

Prior to reform, regulatory structures were created to support the development, implementation and enforcement of reliability standards. In North America,

57. *United States-Canada Power System Outage Task Force (2004a).*

for example, the North American Electric Reliability Council and related regional reliability councils were formed following the 1965 Great North Eastern Blackout to provide industry self-regulation including the development, implementation and enforcement of reliability standards. Other jurisdictions pursued the formation of technical regulatory bodies to oversee and approve industry-developed reliability standards.

However, an institutional framework based largely on industry self-regulation may no longer be considered credible by market participants in competitive electricity markets. Concerns have been raised about the independence and objectivity of such arrangements. Conflicts of interest could compromise the development, application and enforcement of system security rules, or lead to inertia as competing interests are unable to resolve rule-making issues in a timely or effective manner.

The US-Canada Power System Outage Task Force final report suggests that vested interests may have compromised the organisational and financial independence of regional reliability councils to a degree that may undermine their effectiveness. Box 1 provides an example elaborating on these concerns. The Task Force made several recommendations to address these deficiencies, including the development of a stronger and more independent institutional framework and funding mechanisms approved by an independent regulator[58].

Box 1 . East Central Area Reliability Co-ordination Agreement (ECAR) and Regulatory Independence

ECAR was established in 1967 as a regional reliability council, to "augment the reliability of the members' electricity supply systems through co-ordination of the planning and operation of the members' generation and transmission facilities."[a] ECAR's membership includes 29 major electricity suppliers serving more than 36 million people.

ECAR's annual budget for 2003 was USD 5.15 million, including USD 1.775 million paid directly to NERC.[b] These costs are funded by its members in a formula that reflects megawatts generated, megawatt load served and miles of high voltage lines. AEP, ECAR's largest member, pays about 15% of total ECAR expenses. FirstEnergy pays approximately 8 to 10%.[c]

Utilities "whose generation and transmission have an impact on the reliability of the interconnected electric systems" of the region are full ECAR members, while small utilities, independent power producers, and

58. *United States-Canada Power System Outage Task Force (2004a).*

marketers can be associate members.[d] Its Executive Board has 22 seats, one for each full member utility or major supplier (including every control area operator in ECAR). Associate members do not have voting rights, either on the board or on the technical committees that do all the work and policy-setting for the ECAR region.

All of the policy and technical decisions for ECAR, including all interpretations of NERC guidelines, policies and standards within ECAR, are developed by committees (called "panels"), staffed by representatives from the ECAR member companies. Work allocation and leadership within ECAR are provided by the board, the Coordination Review Committee and the Market Interface Committee.

ECAR has a staff of 18 full-time employees, headquartered in Akron, Ohio. The staff provides engineering analysis and support to the various committees and working groups. Ohio Edison, a FirstEnergy subsidiary, administers salary, benefits and accounting services for ECAR. ECAR employees automatically become part of Ohio Edison's (FirstEnergy's) 401(k) retirement plan; they receive FE stock as a matching share to employee 401(k) investments and can purchase FE stock as well. Neither ECAR staff nor board members are required to divest stock holdings in ECAR member companies.[e] Despite the close link between FirstEnergy's financial health and the interest of ECAR's staff and management, the investigation team found no evidence to suggest that ECAR staff favour FirstEnergy's interests relative to other members.

ECAR decisions appear to be dominated by the member control areas, which have consistently allowed the continuation of past practices within each control area to meet NERC requirements, rather than insisting on more stringent, consistent requirements for such matters as operating voltage criteria or planning studies. ECAR member representatives also staff the reliability council's audit program, measuring individual control area compliance against local standards and interpretations. It is difficult for an entity dominated by its members to find that the members' standards and practices are inadequate. But it should also be recognized that NERC's broadly worded and ambiguous standards have enabled and facilitated the lax interpretation of reliability requirements within ECAR over the years.

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a. ECAR "Executive Manager's Remarks," http://www.ecar.org.

b. Interview with Brantley Eldridge, ECAR Executive Manager, March 10, 2004.

c. Interview with Brantley Eldridge, ECAR Executive Manager, March 3, 2004.

d. ECAR "Executive Manager's Remarks," http://www.ecar.org.

e. Interview with Brantley Eldridge, ECAR Executive Manager, March 3, 2004.

Source: US-Canada Power System Outage Task Force (2004a).

NERC reports that considerable progress has been made to improve organisational independence since the 2003 blackout, with all regional reliability councils currently assessed as having open and inclusive membership and fair and balanced governance arrangements[59]. Notwithstanding recent progress, the ECAR example illustrates the potential difficulties with industry self-regulation of transmission system security in competitive electricity markets.

One option to address the issue of independence would be to allocate regulatory responsibility for transmission system security functions to existing industry regulators, as proposed in the joint report of the Italian and French regulators into the Swiss-Italian blackout. Not only would this option deliver institutional independence, it could also facilitate a more integrated and objective regulatory approach to related issues of transmission system security and electricity trade, allowing issues of non-discriminatory system operation to be supervised in an appropriate regulatory context.

However, economic regulators may not possess sufficient technical competence to effectively verify and enforce compliance with transmission system security requirements. In addition, they may not be capable of effectively supervising processes to develop system security rules. This goes to the heart of the issue of regulatory credibility and raises something of a conundrum: an independent body may lack the technical expertise required to effectively regulate system security whereas a technically competent body may become conflicted and exposed to capture by vested interests. The balance between independence and competence needs to be carefully managed.

These issues were addressed in the Australian National Electricity Market by establishing a separate regulatory body – the National Electricity Code Administrator (NECA)[60]. NECA was legally empowered to regulate the system operator to ensure that it complied with transmission system security and other standards specified in the National Electricity Code. NECA was advised on technical matters by the Reliability Panel, which drew its membership from industry experts and transmission owners. The Reliability Panel advised NECA about reliability standards and made recommendations for amendments as appropriate.

The Electricity Modernisation Act 2005 recently enacted in the United States proposes a similar approach. It provides the legal basis for the creation of an independent technical regulator, the Electric Reliability Organisation (ERO), which will be supervised by the Federal Energy Regulatory Commission (FERC).

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59. NERC (2005b).

60. These roles and functions were transferred to the Australian Energy Market Commission, effective from 1 July 2005.

The ERO will have authority to make binding reliability rules. It will also have legal authority to monitor and enforce compliance among control areas within the existing NERC organisational boundary. It will remain an industry body able to draw on the expertise of industry participants. However, its independence will be assured by FERC, which has authority to supervise its activities and to approve its funding arrangements. Its governing board will be representative of all stakeholders. FERC has recently released a Notice of Proposed Rulemaking detailing its proposals for establishing the ERO and related institutional arrangements[61]. The new legislation requires FERC to issue final rules for implementing the new reliability arrangements by February 2006.

Another emerging issue relates to the consistency of regulatory monitoring and enforcement across integrated transmission systems spanning multiple control areas and jurisdictions. A minimum goal should be to establish consistent reliability rules across integrated electricity systems. Approaches adopted by NERC, UCTE, Nordel and in the Australian NEM have sought to establish consistent rules across each region, however, interpretation, application and enforcement can vary considerably across jurisdictions within these regions. There may be a case for developing a single independent regulatory structure to facilitate transparent, objective, and consistent monitoring and enforcement across integrated transmission systems.

A single regulatory body has recently been established to manage an integrated transmission system spanning several regulatory jurisdictions in Australia. The Australian Energy Regulator (AER) assumed responsibility for economic regulation of the Australian National Electricity Market and related transmission systems in June 2004. It is planned to expand the AER's regulatory functions over the next two years to include economic regulation of electricity distribution, and gas transmission and distribution in all states and territories except Western Australia. Once this transfer of regulatory authority has been completed, the AER will have effectively replaced at least 13 jurisdictional regulators at the federal, state and territory level, which were previously responsible for regulating electricity and gas networks in 8 jurisdictions.

Creation of a single regulator structure among multiple jurisdictions raises considerable challenges, particularly in relation to cross-jurisdictional empowerment of the body and oversight arrangements. The challenges can be magnified in an international context, particularly where regulatory arrangements differ fundamentally between countries within an integrated transmission system. For instance, regulatory oversight of transmission systems

61. *See FERC (2005) for details.*

is a federal responsibility in the United States and a provincial responsibility in Canada, which could complicate negotiations around the creation of a single regulatory structure. Efforts to co-ordinate related regulatory activities become particularly important in the absence of such a structure.

Detailed and timely information will be required to support effective regulatory arrangements. Regulators need to be empowered to collect sufficient information to enable them to effectively monitor and verify compliance, and to pursue enforcement cases where necessary. Information gathering powers should be prescribed in a manner that will minimise the compliance burden and provide appropriate protection of confidentiality.

Structural Arrangements

Effective structural arrangements can greatly reinforce the incentives created for transmission system security by the legal and regulatory framework. Structural arrangements should aim to clearly combine roles and functions in a manner that strengthens commercial incentives for efficient reliability and markets outcomes. It should also seek to minimise the potential conflicts of interest that may dilute incentives for effective management of transmission system security.

Structural arrangements possess vertical and horizontal dimensions. Vertical issues refer to how functions and responsibilities for transmission system security are allocated within the electricity value chain, while horizontal issues refer to how functions and responsibilities are allocated across integrated transmission systems. Given the nature of transmission system security, structural issues in this context largely relate to the allocation of system operation functions.

In several markets, system operation functions remain within partially or fully vertically integrated utilities. Combination of system operation, which is essentially a natural monopoly function, with contestable functions such as generation raises immediate concerns about the independence and credibility of system operation. As noted earlier, system operation is of fundamental importance to efficient market operation and effective provision of reliability. Confidence in electricity markets is closely linked to the credibility of its institutions, and particularly to the perceived and real independence and objectivity of its system operators.

The significance of this issue has been recognised. In most cases where system operation functions remain within a vertically integrated structure, they have been organisationally, financially and, in some cases, legally separated from contestable functions. External regulation has been established to monitor the activities of system operators to ensure that they act in a non-discriminatory manner.

However, concerns are beginning to emerge about the effectiveness of these arrangements. For instance, a recent analysis of transmission loading relief (TLR)[62] in the United States suggests that system operators within some vertically integrated utilities may have used the TLR mechanism to curtail scheduled inter-regional power exchanges from generators competing with their incumbent parent utility. Such actions may be very difficult to distinguish from legitimate use of the TLR mechanism to manage congestion; raising the question of whether a regulator would be well placed to identify and respond in a timely manner to any such abuse should it arise. At the very least such concerns can raise the perception that system operators within vertically integrated utilities may be conflicted and may use reliability as a means of masking anti-competitive behavior[63].

Independence and objectivity could be strengthened by ownership unbundling of system operating functions from contestable components of the value chain. Ownership unbundling would help to reinforce incentives for transparent and non-discriminatory behaviour that are more closely aligned to efficient management of system security and market-based dispatch. It would also remove any related conflict of interest that could influence operator interventions and possibly adversely affect transmission system security. Ownership unbundling of system operation functions could help to enhance the real – and perceived – credibility of system operation in competitive electricity markets.

Transmission system security could be strengthened through greater aggregation of system operating functions across integrated transmission systems spanning multiple control areas. North America and continental Europe, in particular, have large integrated transmission systems with many control areas, which presents substantial challenges for effective co-ordination and management of transmission system security, particularly in response to disturbances and emergency situations. This challenge is probably greatest in North America where transmission system security within the area covered by NERC is managed by around 140 separate control areas within 3 integrated transmission systems. Figure 26 illustrates the extent of the challenge.

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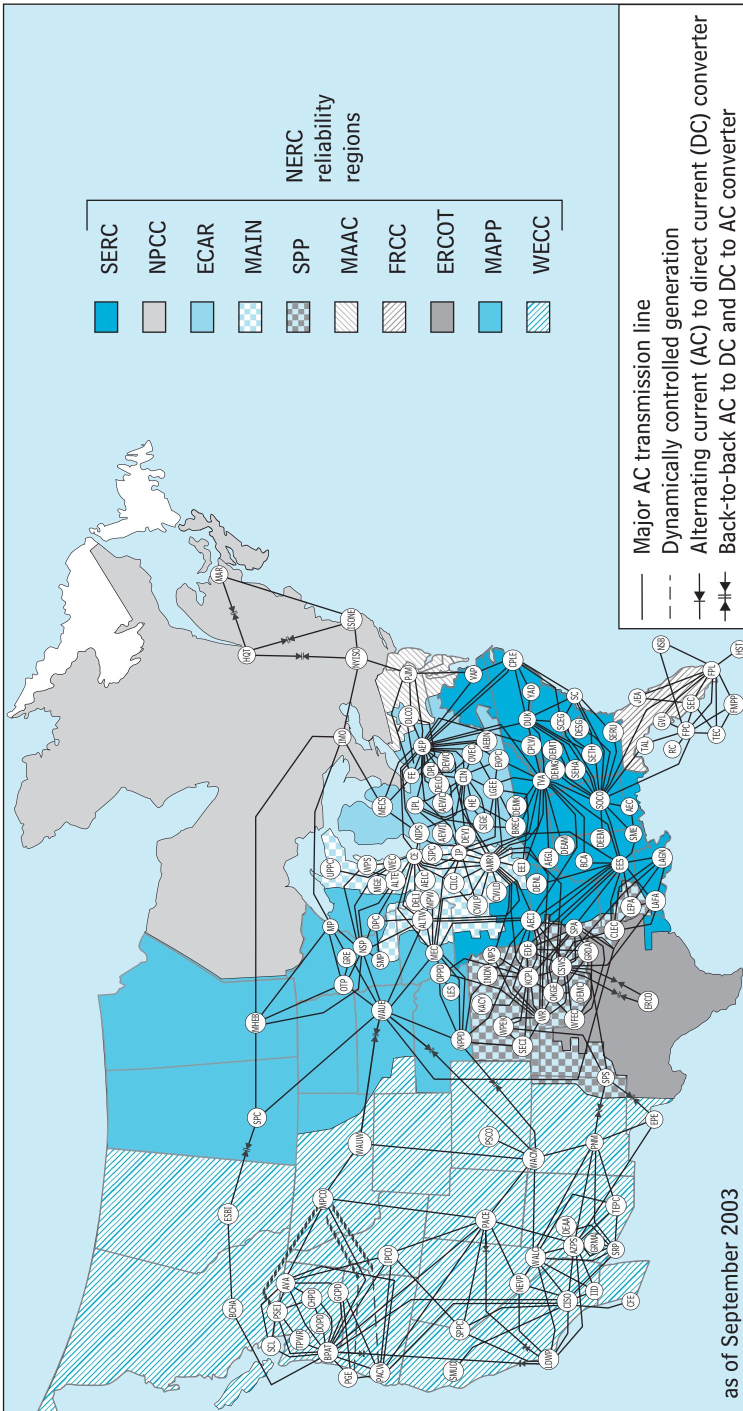
62. The transmission loading relief mechanism was introduced by NERC for the North American Eastern Interconnection in the late 90s, essentially to provide a means of managing potential overloading of key transmission lines. The TLR mechanism incorporates 6 main levels reflecting increasing risk to the transmission system. TLR levels 3-5 involve actual curtailment of transfers, while TLR level 6 signifies an emergency action.

63. Moss, D. (2004).

Figure 26

NERC Regions and Control Areas



Source: US-Canada Power System Outage Task Force (2004a).

The fractured responsibility for transmission system security resulting from this distribution of functions has led to the creation of a complex institutional framework to help manage transmission system security across each integrated transmission system involving reliability co-ordinators, regional reliability councils and, ultimately, NERC.

These issues have been recognised and several different approaches are emerging in competitive electricity markets to address them. In the United States, a system of regional transmission organisations is being implemented to help co-ordinate the activities of individual control areas within larger regional markets. In the Nordic region, independent system operation is undertaken by transmission system owners in each country with co-ordination achieved through co-operative agreements that address operational standards and emergency procedures. In the United Kingdom, system operation is undertaken by a single independent transmission owner, and market operation is independent of the transmission owner. In Australia, an integrated market and system operator has been established to enable effective whole-of-market system operation for the interconnected transmission network. The market and system operator is independent of the transmission network owners.

In the case studies, institutional complexity created a degree of uncertainty and co-ordination problems, particularly in the North American and Swiss-Italian cases, which may have delayed timely and appropriate system operator intervention. By contrast, the Australian case study illustrates the benefits of an integrated, independent system operator (ISO). In this case, NEMMCO was able to efficiently mobilise resources from several inter-connected regions to successfully manage a major system emergency that could easily have led to system-wide collapse. Although some load shedding occurred, system collapse was avoided and services were fully restored within 1.5 hours. This suggests that institutional arrangements involving a single ISO with clear responsibility for an entire integrated network can provide an effective means of managing emergency events in real time to minimise impacts and deliver least-cost outcomes.

Greater consolidation of system operation functions across integrated transmission systems has the potential to reduce transaction costs, increase consistency of application of reliability rules and improve real-time co-ordination and action to manage transmission system security. However, these benefits may accrue at the expense of more flexible, local responses to manage system security. More localised control areas may provide greater flexibility to accommodate local differences in market rules, structures, generation and fuel mix and public policy.[64]

64. Vandenberghe, F. (2004); and Kirby, B and Hirst, E. (2002).

Excessive aggregation has also been criticised for potentially exposing integrated transmission systems to greater risk of system operator error, which could have a more immediate impact on power flows over a much larger area compared to system operation based on more localised control areas. There may be an intuitive appeal to this view. However, any such benefits associated with highly localised system operation could be outweighed by the additional co-ordination costs and inherent inertia such arrangements suffer in responding to emergency situations that need to be addressed in real time. Rather than reducing the potential for error, multiple system operators acting in relative isolation with little knowledge of real-time system conditions beyond their control areas may be more likely to misjudge real-time conditions and, hence, to make erroneous interventions that may threaten system security within and beyond their control areas.

Integrated alternating current transmission networks are particularly susceptible to the failure of any integrated component, the effect of which can cascade through an interconnected network almost instantaneously. Hence, the impact of an error is not necessarily lessened by localised system operation compared to a more consolidated model. Further, effective co-ordination may prove difficult or even impossible under certain real-time conditions in an environment where multiple system operators need to co-ordinate their actions to identify and manage an emergency event. A single independent system operator with a holistic, real-time perspective of an integrated transmission system and with sufficient resources to manage credible emergency events is in a strong position to effectively respond to such events in a manner that minimises their overall impact.

A more compelling concern may be the practical challenges of further aggregation. It has been claimed that it would not be practically possible for a single system operator to effectively manage and coordinate the many thousands of simultaneous transactions undertaken at any time in a large integrated transmission system like the Eastern Interconnection in North America or the UCTE system in continental Europe. Effective system operation would require more localised control, even if under the banner of a single system operator, which would imply the need for ongoing coordination of system operator activities[65].

Furthermore, a single integrated ISO spanning multiple jurisdictions may not be acceptable from a public policy perspective. It may also raise legal, technical and organisational challenges in a cross-jurisdictional context, not

65. Alvarado, F. and Oren, S. (2002).

the least of which may involve convincing incumbent transmission system operators to give up some control over their transmission assets[66].

Under an ISO model, separation of the system operation functions from transmission ownership may also raise challenges associated with clarifying the respective technical roles and responsibilities for co-ordinating system operation and network management. It also raises the challenge of ensuring that the ISO acts in a manner that does not devalue transmission assets or in any other way cause undue financial loss for the transmission owner.

Notwithstanding these concerns, appropriate aggregation of system operation functions can strengthen co-ordination of system security, leading to more efficient responses to disturbances and emergency events in real time. The potential benefits are too great to be ignored. A key issue revolves around defining an appropriate level of aggregation that balances the potential benefits and costs.

Improving Transmission System Security Standards..........

Official investigations of the events described in the case studies focused considerable attention on the rules and practices governing transmission system security. These reviews suggest that opportunities exist to reform operating rules and practices so that they can provide a more effective means of ensuring transmission system security in the more dynamic, real-time and integrated operating environment created by electricity market reform.

Transmission system security standards have typically changed little since the introduction of electricity market reform. In practice, great reliance is placed on the N-1 standard. This methodology has the advantage of being relatively simple to compute, implement and monitor. It is typically applied in a deterministic manner[67] based on the notion of managing a single credible contingency and returning the transmission system to a stable and secure condition within a minimum timeframe, usually somewhere between 15 and 30 minutes. It provided an effective and practical framework for managing system security in the operational conditions existing prior to electricity reform.

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66. Bialek, J. (2004).

67. Deterministic *application in this context refers to the criterion being applied in a manner that delivers the same level of protection to all points in an integrated system (or control area) at the same time, irrespective of the likelihood of failure or the potential impact failure would have on the overall reliability of an integrated transmission system.*

However, the case studies reveal that transmission systems have become more dynamic with the advent of electricity market reform. Transmission systems are driven more efficiently and closer to security limits for longer periods than in the past. Although this may not necessarily increase the risk of an N-1 event, it may increase the potential impact of such events. It may also increase the probability and potential impact of multiple dependent contingencies, particularly as they are likely to occur within the timeframes usually given to return the transmission system to a secure operational state.

In view of these concerns, questions are being raised about the relevance of the current standards and the extent to which they provide an appropriate basis for transmission system security in competitive electricity markets spanning larger integrated networks. Several suggestions have been advanced to improve the effectiveness of transmission system security standards in the wake of the 2003 blackouts.

An immediate response was to pursue ways to strengthen the legal basis for enforcement. Proposals to strengthen the legal framework have been discussed previously. Such proposals aim to extend coverage to all relevant parties and to make standards legally binding. Mandatory application of transmission system security standards would greatly strengthen compliance with existing standards. However, improved compliance with existing reliability standards would not address the fundamental effectiveness of existing standards in reformed electricity markets.

Another option would be to extend the existing standard to increase the absolute level of security delivered. This could be achieved, for example, by moving from an N-1 standard to an N-2 standard. Although an N-2 standard would generally increase the level of transmission system security within an integrated transmission system, it may do so at great cost. Figure 27 presents a very simple example to illustrate this point.

Deterministic application of a more stringent security criterion to all transmission lines within an integrated transmission system or control area, regardless of the risk of failure or potential consequences for transmission system security, would represent a poorly targeted response to strengthen system security with the potential to substantially increase total costs. Deterministic approaches are also by nature static and do not readily permit real-time incorporation of dynamic factors affecting transmission system security, such as angle stability, voltage and frequency conditions[68].

68. Bialek, J. (2004).

Figure 27

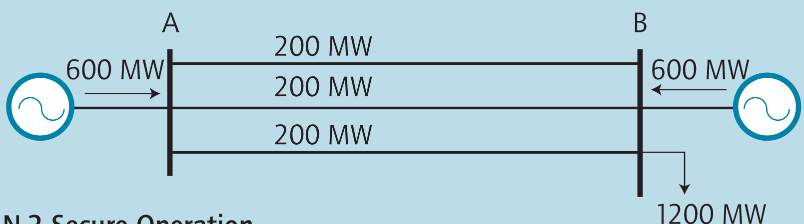
Cost Comparison of N-1 and N-2 Security: Simple Example

Assumptions

- *In this example, two regions (A and B) form an integrated electricity market and are interconnected by three transmission lines with a maximum rated capacity of 300 MW each.*
- *A load of 1 200 MW is connected in Region B.*
- *The system marginal price of electricity in Region A is USD 20/MWh, while in Region B it is USD 50/MWh.*

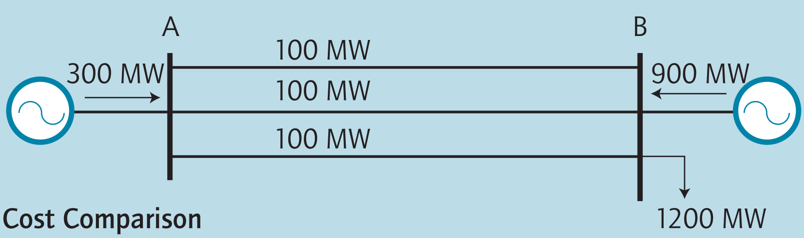
N-1 Secure Operation

Application of an N-1 security criterion in this example would mean guaranteeing power transfers between Region A and Region B if one of the 300 MW transmission lines was lost. As a result, the maximum power transfer on each of the three transmission lines would be 200 MW.



N-2 Secure Operation

Application of an N-2 security criterion would double this requirement, leading to a maximum total transfer capability on each line of 100 MW.



Cost Comparison

- *The hourly cost of adopting an N-2 security standard would be the difference between the system marginal price in each region multiplied by the reduction in transfer capacity. In this example that would be USD 9,000 (ie. USD 30 × 300 MW), representing an increase in electricity costs of around 20%.*

Source: Krischen, D. and Strbac, G. (2004).

An alternative, more radical option could involve modifying the way the N-1 criterion is interpreted and applied, to provide a more flexible and adaptable approach for managing transmission system security that better reflects more dynamic and uncertain real-time system operating conditions. Current deterministic approaches could be enhanced with probabilistic methodologies. Probabilistic techniques could be used to identify and assess factors that may affect transmission system security and to calculate the risk of failure and impact of failure using indices such as probability, frequency, duration and severity.

For instance, probability risk assessment (PRA) has been successfully applied in several industries with complex engineering systems that are exposed to low probability, high consequence failures, such as the nuclear power sector. PRA involves calculating a measure of the probability of undesired events on the transmission system and a measure of the severity or impact of those events.

Considerable progress has been made toward the development of PRA tools to support contingency planning and real-time system operation. For example, the Electric Power Research Institute (EPRI) as part of its Power Delivery Reliability Initiative has developed several PRA related methods and tools for the electricity industry[69].

Probabilistic methods may facilitate the development of more effective risk management strategies, including more pro-active targeting of contingency resources to meet transmission system security standards at least cost. According to EPRI, PRA offers several potential advantages for real-time system operation including:

- helping to identify component failures that would most jeopardise transmission system reliability and components most affected by the failure of other system components;
- providing a more effective means of simulating and evaluating transmission system behaviour under various conditions to identify weak points and bottlenecks;
- supporting the development of efficient response strategies to address transmission system security vulnerabilities; and
- enabling the effective operational reliability of the transmission system to be measured objectively at any point in time.

Ideally PRA should consider every possible scenario. However, in large integrated transmission systems this would require a prohibitively large number of

69. The following discussion on PRA is drawn from several EPRI publications including EPRI (2001) and EPRI (2003c).

calculations. EPRI's solution was to develop a hybrid methodology that involves undertaking a reliability assessment of a representative set of simulations, resulting in an estimation of reliability. As a result, the EPRI methodology combines probabilistic and deterministic features to develop a practical approach.

Achievements to date have included the development of a series of integrated software packages. Key among these is the Physical Operation Margin (POM) program and the Probabilistic Reliability Index (PRI) program. The POM program can simulate a large number of contingencies quickly and determine their likely impacts, including identifying those most critical to system security. Its outputs are a list of potential contingencies including voltage violations, thermal overloads, voltage instability and loss of load. POM results are then fed into the PRI program, which computes probabilities for various contingencies. It then multiplies the probability of critical contingencies by the potential impacts to determine reliability indices for each potential event. Box 2 provides further information on EPRI's PRA methodology.

Box 2 . Overview of EPRI's Probability Risk Assessment (PRA) Methodology

EPRI's PRA methodology consists of a range of software packages that provide probabilistic results that allow system operators to incorporate the probability of a contingency event into their operational contingency analysis and preparation. Key software components include the Physical Operation Margin (POM) program and the Probabilistic Reliability Index (PRI) program.

Physical Operation Margin Program

The POM software program essentially simulates power transfers while monitoring technical constraints. The software can simultaneously monitor voltage stability, voltage constraints and thermal constraints while calculating voltage stability margins. POM provides flexibility in monitoring these constraints. For example, thermal constraints can be monitored based on total power flow (MVA) or current loading (MVA/pu). Voltage constraints may be monitored at load buses, or different voltage limits may be monitored at different buses. The program automatically generates N-1 and N-2 contingency lists and performs simultaneous contingency and transfer studies by identifying critical contingencies for each transfer level and by determining the location type *and severity of potential system security violations. The program is available in two versions to support contingency planning and real-time operation.*

Probabilistic Reliability Index Program

Output from POM and other probabilistic data become inputs for the PRI program. The PRI program calculates the likelihood of a simulated outage and its physical impact or severity. Each contingency is deduced from a unique combination of the availability and unavailability of pieces of equipment, with each unique situation assigned an occurrence probability. For every simulated situation (i), the PRI calculates the sum of its impact (I_i) and its occurrence probability (p_i) according to the formula:

$$PRI = \Sigma p_i I_i$$

In this equation, "probability" represents the likelihood of experiencing the impact (the probability of the initiating events – contingencies that could lead to violations of operating security limits – that cause the impact). "Impact" represents the calculated severity, which includes deviations from:

- *acceptable thermal loading of transmission lines and transformers;*
- *acceptable bus voltage levels;*
- *voltage stability; and*
- *dynamic stability (in some systems).*

The impact may be measured by the distinct number of buses or lines that experience voltage violations or overloads. The results can also be presented as an aggregate reliability index which is the sum of the product of the occurrence probability multiplied by its severity. For example, a voltage index could be calculated as the sum of the product of the probability and amount of the voltage deviation below a certain level, summed over all outage situations and summed over all buses with violations. Similar reliability indices can be defined using this methodology for thermal overloads, voltage stability and dynamic stability.

However, it is generally not possible to evaluate all possible contingencies in real-time using this methodology due to the huge number of potential contingency events associated with large integrated transmission systems. In practice, a representative set of simulations would be analysed to provide an approximation of system reliability.

Source: EPRI.

EPRI's methodology has undergone extensive testing and yielded some promising results, particularly in the context of improving contingency planning. Box 3 provides a summary of recent experience from utilities involved with testing the methodology.

Box 3 . Applying PRA Methodologies: Three Case Studies

Consolidated Edison Company of New York

Consolidated Edison Company of New York (Con Edison) is a regulated utility serving 3.1 million customers over a 660 square mile area that includes most of New York City.

Con Edison undertakes internal reliability assessments that incorporate probabilistic methodologies. Programs includes: transmission system analysis using contingency analysis programs, physical operating margin and reliability evaluation programs; probabilistic representation of component failures; planning for multiple contingencies; and prioritising outages and maintenance work.

Con Edison has developed a network modelling program to evaluate the risk of cascading failures and widespread outages, which the company uses to target its maintenance expenditures. Con Edison has also developed a detailed probabilistic reliability model for planning, and extended this model to provide its system operators with a reliability monitor for outage management. The company's PRA methodology provides a coherent and quantitative structure enabling its system planners and operators to make accurate reliability decisions. The methodology also enables the company to integrate its maintenance and operations functions.

The company is planning to complete a detailed model of its entire bulk transmission system including all substations in time for a comprehensive planning process in 2008. Con Edison intends to continue to use PRA methods to support planning analysis, to analyse how to deploy and augment its assets and to provide reliability monitoring and management tools for its system operators.

Entergy Corporation

Entergy Corporation is an integrated utility, serving around 2.4 million customers and 22 000 MW of load in Louisiana, Mississippi, Arkansas and Texas. Its 500 kV transmission system includes 15 500 miles of *transmission lines, 1 450 substations and 14 interfaces with neighbouring control areas with over 75 points of interconnection.*

From a system operating perspective, Entergy faces dynamic and less predictable system conditions, especially loop flows. To address some of its system planning issues, Entergy created a transmission outage database to use in its load flow analysis process. It used EPRI's POM and PRI software to evaluate potential reliability projects. Entergy found that the POM software provided fast and robust simulations, while the PRI program was easy to learn and use. Entergy plans to continue to use the PRA methodology to improve understanding of its transmission system and to justify and develop future projects to improve transmission system reliability.

American Electric Power

American Electric Power (AEP) is one of the largest electric utilities in the United States with nearly 5 million customers linked to its 11 state transmission system. It is the largest power producer in the United States. It operates over 42 000 MW of generation in the United States and abroad.

AEP is using PRA as part of a 4-phase project to strengthen its system planning and management. Phase 1 is underway and involves developing knowledge and experience in using the PRA tools. Phase 2 will involve application of the tools to transmission system operations. Phase 3 will involve extending application to system planning functions. Phase 4 will involve an evaluation of outcomes, including an assessment of PRA compared to other probabilistic methodologies.

Source: EPRI.

Work is progressing to adapt these tools to support real-time system operation. Development of a visualisation tool (the Community Activity Room – see Box 4 for a brief description) is progressing, as is work to combine the visualisation tool with the other PRA software to create a visual online probabilistic risk monitor that would have the potential to provide a visual representation of transmission system security in real time.

The development and successful application of real-time probability assessment tools would greatly assist the incorporation of probability methodologies to enhance transmission system security standards. They would also have the potential to support greater co-ordination of contingency planning and real-time management of transmission system security, possibly leading to an eventual convergence of these activities. Application of PRA would also be supported by technologies that provide system operators with greater direct control over power flows, such as flexible alternating current technologies (see Box 4 for further description of FACTS).

Scope may exist to extend the application of probability risk assessment to incorporate some measure of the cost of potential impacts. Contingency analysis using PRA could be further refined to incorporate an estimate of the value of lost load[70]. This approach may provide a means to encourage management of transmission system security to be more responsive to the value markets might place on reliable delivery of electricity.

Processes to develop and review transmission system security standards need to be transparent, objective and inclusive, given that transmission system security is a shared responsibility and that management of system security has implications for operation of markets and the commercial interests of market participants. Active stakeholder participation can help strengthen the credibility of these processes and ensure that the outcomes are consistent with the level of transmission system security market participants require. For instance, from a user's perspective, reliability has multiple dimensions including the cost of poor power quality, the cost of mitigation measures, and willingness to pay. These issues can not be effectively addressed without participation of electricity end users[71].

The need for transparency and greater stakeholder participation is beginning to be recognised. For example, NERC noted in a recent report the efforts made by all reliability regions to develop more open and inclusive memberships and to adopt fair and balanced governance arrangements[72]. Maintaining effective transparency, objectivity and inclusiveness will remain an ongoing challenge. Lack of technical expertise may represent a barrier to effective participation for some stakeholders, particularly end users. Education and, possibly, funded representation or regulatory representation should be considered to address such deficiencies if they emerge.

70. *Value of lost load (VoLL) can be defined as the monetary value consumers place on a marginal unit of electricity consumed. Defining VoLL is problematic given the relative weakness of demand-side participation in electricity markets and the quite different valuations different consumers are likely to place on electricity consumption at the margin. As a result, it is generally used to refer to the highest monetary valuation among all potential consumers for the marginal unit of electricity consumed. Hence, it can be used to define the maximum price consumers would be willing to pay in exchange for not having to reduce electricity consumption at the margin.*

71. *Burns, R., Potter, S. and Witkind-Davis, V. (2004).*

72. *NERC (2005b).*

Co-ordination, Communication and Information Exchange

System operating practices are key determinants of actual transmission system security. They translate the incentives created by the governance regime and security standards into practical activities that provide the means for delivering transmission system security.

In general terms, system operating practices in relation to transmission system security have changed little with the introduction of electricity reform. The fundamental basis for system operation remains the local control area. Local system operators remain largely responsible for operational contingency planning and secure system operation within control areas, and can act in an operational context without a great deal of co-ordination or consultation.

Co-ordination among system operators within larger integrated transmission systems has been enhanced to a degree to take account of greater interregional electricity flows. Various mechanisms have been developed to improve day-ahead exchange of information on projected trade flows, such as the Day-Ahead Congestion Forecast system in continental Europe, the Open Access Same Time Information System in North America and the Nordic Operational Information System (NOIS) system in Nordel. The NOIS system also provides the platform for the Nordic balancing market. In some cases an institutional framework has been placed over the top of control areas to improve co-ordination and information exchange in relation to reliability and power flows, such as the NERC framework in North America or the System Operation Agreement in the Nordic region. However, co-ordination and communication continues to be handled largely on an exception basis in the context of managing transmission system security, particularly in real-time.

The more dynamic operating environment created by unbundling, decentralised decision-making and greater interregional trade needs to be appropriately reflected in operating practices if they are to continue to ensure effective transmission system security in competitive electricity markets. In particular, operating practices need to be flexible and adaptable to permit effective real-time response to system emergencies and disturbances. Contingency planning and emergency responses need to be undertaken from a whole-of-system perspective, reflecting the shared nature of responsibility and action required to maintain transmission system security, particularly in integrated transmission systems spanning multiple control areas. Effective co-ordination and communication is vital for successful system operation to maintain transmission system security.

Co-ordination

Co-ordination in this context has vertical and horizontal dimensions. Vertical dimensions refer to the co-ordination between system operators and other parties in the value chain including generators, distribution network operators and users. Horizontal dimensions largely refer to co-ordination between system operators across integrated transmission systems that span multiple control areas. The greatest co-ordination challenges are likely to occur in integrated transmission systems with multiple control areas.

The US-Canadian and Swiss-Italian case studies show that effective management of an emergency event may require a response co-ordinated in real-time, rather than a collection of individual responses. In the Swiss-Italian case study, the Swiss transmission system co-ordinator, ETRANS, could not effectively manage the emergency situation with the resources solely under its control. Support was required from Italy. However, from GRTN's perspective there was no problem requiring its immediate response as its portion of the integrated network was operating in an N-1 secure condition at the time of the original Mettlen-Lavorgo line trip[73]. UCTE's analysis drew attention to the same issue, and went further to suggest that effective operational contingency planning would also be problematic in an integrated transmission system spanning multiple control areas given that no single system operator has the capacity to assess or manage the related systemic risks[74].

Given the speed with which emergency situations can materialise and spread across integrated transmission systems, it is not surprising that effective emergency responses involving co-ordinated manual interventions in separate control areas are virtually impossible to organise in real time. The decentralised operational model is inadequate and too slow to respond to real-time emergencies spanning multiple control areas[75]. The need for real-time flexibility to respond in this more dynamic operational environment can magnify the co-ordination challenge.

Co-ordination that facilitates integrated real-time operation and emergency responses across multiple control areas would greatly improve contingency preparation and management of system security. Interaction between control areas needs to move beyond day-ahead information exchange and exception based co-ordination closer to real time. Co-ordinated real-time security assessment and control is required.

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73. CRE and AEEG (2004).

74. UCTE (2004a).

75. Bialek, J. (2004).

Nordel has an effective multilateral agreement that incorporates protocols for coordinated actions to address aspects of transmission system security where responsibility is shared[76]. UCTE has recently implemented a multilateral agreement to enforce its operating standards across continental Europe. However, potential may exist to further develop multilateral approaches where system operators within an integrated region jointly prepare contingency plans with agreed protocols for co-ordinated action in the event of an emergency situation.

Appropriate operating practices need to be supported by real-time data exchange and communication, to facilitate effective real-time and holistic security assessment and system control. An effective ongoing commitment to real-time data exchange and communication will also be required.

However, implementation of more integrated and coordinated system operation is likely to raise organisational, legal, technical and local challenges, particularly across transmission systems spanning several jurisdictions[77]. Tension associated with the competing objectives of maximising capacity for trade and maximising contingency reserves to ensure transmission system security may need to be addressed in this context. Confidentiality of information exchanges may also need to be addressed.

Managing the impact of system disturbances across integrated systems spanning multiple jurisdictions and control areas may also need to be addressed. Co-ordinated emergency responses that lead to load shedding in adjacent or distant control areas or jurisdictions may undermine public support for co-ordinated action and lead to practices that may not be consistent with an effective, holistic emergency response[78]. Tensions were revealed in the case studies, in North America and Australia in particular, in relation to the use and impact of emergency load shedding. In North America, concerns were raised that load shedding was delayed or not considered because of the potential legal liabilities. In Australia, concerns were raised about the distributional impact, with claims that one jurisdiction bore an undue share of the loadshedding burden[79].

Details in relation to these and other operational practices need to be carefully considered and developed in consultation with all key stakeholders, especially governments. Greater transparency in the development and implementation of emergency procedures will promote better understanding

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76. Hagman Energy AB (2005).

77. Bialek, J. (2004).

78. See Kirby, B. and Hirst, E. (2002) for further discussion of this issue.

79. NEMMCO (2005a) and (2005b).

among stakeholders about the potential impacts and can strengthen support for appropriate actions taken to protect system security in an emergency situation. For instance, experience in Denmark and Australia suggests that there is considerable value in agreeing load shedding priorities in advance and making those priorities transparent so that potentially affected parties are aware and can respond[80].

Communication and Information Exchange

Effective communication and information exchange provides an essential platform for improving system operator situational awareness and for developing more effective operational planning and co-ordination of transmission system security, particularly in integrated transmission systems spanning multiple control areas. Public access to accurate and timely information would also permit independent assessment of transmission system security, creating the transparency required to support more effective governance and regulation. It may also support the development of efficient and innovative market-based responses, particularly to emerging transmission congestion.

The North American and Swiss-Italian case studies in particular highlight the importance of effective and timely communication and information exchange, with investigations finding that poor communication and information exchange contributed to a lack of situational awareness that undermined effective emergency responses[81].

Opportunities exist to improve the quality of information available to support operational contingency planning and transmission system security management, particularly during emergencies. Accurate, real-time information is required to support effective contingency preparation and emergency responses. The North American event in particular shows that electricity flows can become very volatile following an N-1 contingency event, highlighting the importance of accurate, real-time information.

Information also needs to provide a holistic picture of an integrated transmission system, to support effective co-ordinated management of transmission system security. Greater harmonisation of data standards could improve the quality of

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80. Elkraft System (2004a) and NEMMCO (2005a). In the Australian case study, reaction to load shedding in Queensland, which bore the brunt of the disruption, may also have reflected the very negative response of the media and public to disconnections that largely affected residential consumers (around 250 000 of them), whereas in other states the load-shedding protocols agreed to with state governments disconnected large industrial loads as a first priority. This suggests that even where load-shedding priorities are agreed in advance, support may evaporate in the face of public criticism, which highlights the importance of careful examination of any load-shedding priorities to ensure they minimise the impact of disruptions to the greatest extent possible.

81. CRE and AEEG (2004); and US-Canada Power System Outage Task Force (2004a).

information, and promote more effective information exchange between system operators within an integrated transmission system. Technology also offers potential to improve the accuracy and timeliness of data gathering and analysis. This potential is discussed in the investment section below.

Efforts to improve information exchange are not without their challenges. For instance, some utilities may resist greater information sharing for commercial or confidentiality reasons. Such issues can be addressed to a large degree through the governance framework by minimising any commercial conflicts of interest resulting from ill-defined regulatory or structural arrangements.

The need for more accurate and timely information has been recognised and various efforts are progressing to improve the quality of information and exchange of information between system operators. For example, Nordel is refining its NOIS information exchange platform to improve the accuracy and real-time flow of information between control areas. These enhancements have the potential to improve real-time situational awareness in relation to power flows, bottlenecks, reserves and lines out for maintenance in neighbouring control areas. Such developments will provide more effective information exchange between control areas, helping to improve co-ordination of operational planning and system operation in real-time. In particular, these enhancements have the potential to support more effective management of operational reserves on a holistic Nordic basis[82].

Efforts are also being made to improve communication between system operators. For example, UCTE noted that ETRANS and GRTN took immediate steps to improve their communication arrangements following the Swiss-Italian event in the context of a wider process to improve co-operation and co-ordination[83]. NERC also noted recent improvements to hardware and procedures to support more effective communication between reliability co-ordinators in North America. NERC is also upgrading its Reliability Coordinator Information System, which is an on-line, real-time messaging system that provides a key means of sharing emergency alerts between reliability co-ordinators and many control areas[84].

Other stakeholders including governments, generators, distribution system operators, end users and the community also expect to be kept well informed about events that affect the reliability of electricity services, particularly disruptions, and efforts to restore services following an outage.

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82. Nordel (2004b) and (2005a).

83. UCTE (2004a).

84. NERC (2005b).

Experience from the case studies indicates the importance of effective communication with key stakeholders and the community, especially during the restoration period in the wake of a major disruption. In each case, system operators faced tremendous demand for timely relevant information on the nature of the disturbance and efforts to restore services. Various strategies were employed to keep stakeholders informed.

For example, in Ontario, the IMO activated its Crisis Management Support Team (CMST) within minutes of the disturbance to co-ordinate emergency management, including providing a central point for information dissemination. Throughout the emergency, CMST communicated with key industry, end user and government stakeholders by conference call and through the IMO's secure website. CMST held 30 conference calls with key stakeholders during the 8-day restoration period. Information was provided to the general public through media releases, interviews and through regular updates on the IMO website. The IMO supported the government's emergency communications by providing real-time system status updates and by responding to technical questions[85].

Elkraft implemented its information preparedness plan in response to the 2003 Swedish-Danish blackout. The plan required Elkraft to inform the authorities as soon as possible and to then ensure that major media outlets with the widest possible public reach were informed about the cause, extent and likely duration of the disturbance. Consistent with the plan, control room operators informed the Copenhagen Police a few minutes after the outage. The police then informed the media. DK Radio News was first to be advised officially of the event given its large regional penetration in Zealand, where the outage had its greatest impact. DK Radio News had a journalist stationed at Elkraft System during the course of the restoration. Other media were then informed with priority given to radio, television and other electronic media. Elkraft System also gave priority to television interviews. A press conference was held the day after the event to explain the cause of the power failure and course of the restoration. Elkraft System stationed an engineer at the Copenhagen Police Headquarters to facilitate communication with government authorities. Elkraft's communication strategy was well received and succeeded in reducing pressure on civil emergency call centers[86].

Market messaging systems were also used to keep market participants informed. During the Australian event, NEMMCO employed SMS messaging to improve communication with government officials.

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85. IMO (2004).

86. Elkraft System (2003).

Event investigations reinforced the need for effective communication with governments. They also noted the potential to enhance emergency communications; through, for example, advance preparation of emergency communication strategies and improving the resilience of control centers and official websites to power failures.

Investing in Transmission Capacity

One of the more immediate reactions following the spate of large-scale blackouts in 2003 was to suggest that the transmission infrastructure was inadequate and that major new investment in transmission capacity was needed to improve transmission system reliability.

Although investment in transmission capacity may help to improve transmission system security to a degree over a period of time, it is not likely to be a critical factor in the context of managing the 'operational' reliability of an existing transmission system. Transmission investment issues are of greater importance in the context of discussions about the adequacy of existing capacity to meet growing demand for transmission services. Such issues are critical for the efficient development of electricity trade and for maximising the benefits from electricity reform. These issues are discussed in the IEA publication *Lessons from Liberalised Electricity Markets*.

Transmission system security, however, is not simply a function of available transmission line capacity. Under standard operational practices, system operators are bound to operate any transmission system irrespective of its capacity within its security limits. Hence an N-1 security criterion, for example, can be applied effectively to a transmission system whether it has 'excess' transfer capacity or not. In cases where capacity is relatively scarce, system security requirements will take precedence to ensure that sufficient transmission capacity is set aside to accommodate credible N-1 contingencies, and transfer capacity will be reduced. This can have significant implications for efficient inter-regional trade, but is less important from a transmission system security perspective.

To the extent that investment in new transmission line capacity creates 'spare' capacity, it may help to increase effective transmission system security. Applying an N-2 criterion would have a similar effect. However, both of these approaches could be very expensive and the outcomes may not be certain. Investments in integrated transmission systems should be considered from a holistic perspective. Individual expansions or additions may simply serve to move points of congestion elsewhere in the transmission system, delivering no net improvement in transmission system security.

Alternatively, 'spare' capacity may facilitate more interregional trade, especially where investment alleviates transmission congestion between regions with chronic wholesale price differences. As power flows increase, 'spare' transmission capacity will be absorbed until flows reach security limits. At that point, system security would be much the same as it was before the expansion, with the investment providing only a temporary improvement in overall transmission system security. It is even possible that such investment may serve to marginally increase the probability of a system disturbance due to the higher exposure to network instability resulting from longer distance power flows[87].

However, there are other investments that have the potential to significantly improve transmission system security. Investments in upgrading and improving system operating tools would have the potential to enhance system operators' capacity to effectively monitor, understand and more flexibly control transmission systems in real time. Investments to strengthen the competence and expertise of system operators and other professionals directly involved in the task of maintaining system security could also serve to improve real-time responses, particularly during emergency situations. Investments that enhance the likelihood of system components operating as designed, especially during emergency situations, may also help to improve transmission system security.

Investing in Technology

Transmission system security cannot be achieved without effective system management and operating tools. Effective system operating tools allow system operators to assess and prepare for potential contingencies, provide effective monitoring and situational awareness, and enable timely intervention in real time to manage potential emergency situations or to return power systems to a secure operating state after the loss of key equipment.

The potential for developing and deploying technologies to improve operating tools to enhance transmission system security is vast, covering the whole range of activities from operational contingency planning through to security monitoring and network control. Technology has the potential to improve the accuracy, quality and timeliness of information. It can also support the development of more accurate and dynamic system modeling, which in turn can support more flexible and adaptable contingency preparation and promote greater real-time situational awareness.

87. For further discussion of these issues see Kirschen, D. and Stribac, G. (2004); and Bialek, J. (2004).

Table 8

Examples of Technologies with the Potential to Enhance Transmission System Security

Technology	Description	Development status
High-temperature superconducting cables	Superconducting ceramic cables can carry much more current than standard wires of the same size, with extremely low resistance, allowing more power to flow in existing right-of-ways. But the required refrigeration results in higher initial and ongoing costs.	Demonstration project underway with cables up to 400 ft. Self-contained current limiters are close to commercial availability.
Underground cables	Underground cables transmit power with very low electromagnetic fields in areas where overhead lines are impractical or unpopular. Costs are 5 to 10 times that of overhead lines, and electrical characteristics limit AC lines to about 25 miles.	Widely used when overhead is not practical, mostly in urban areas and underwater. Research is ongoing to reduce costs.
Advanced composite conductors	New transmission conductors with composite cores, as opposed to steel cores, are both lighter and have greater current-carrying capacity, allowing more power to flow in existing right-of-ways.	Just entering commercial testing. More experience is needed to lower total life cycle costs.
More compact transmission line configurations	New computer-optimised transmission line tower designs allow for more power to flow in existing right-of-ways.	Commercially available, with increasing use.
Six or twelve phase transmission line configurations	Nearly all AC high voltage power transmission is performed using three phases. The use of six or even twelve phases allows for greater power transfer in a particular right-of-way with reduced electromagnetic fields due to greater phase cancellation.	Demonstration lines have been built. Key challenge is cost and complexity of integrating with existing three-phase systems.

Sources: US DOE (2002); EPRI (2003b); EPRI (2003c); Gellings, C. (2004a); Hauer, J. et al. (2002); and IEA (2004b).

Table 8

Examples of Technologies with the Potential to Enhance Transmission System Security (Continued)

Technology	Description	Development status
Modular equipment	Modular equipment designs provide greater transmission system flexibility, allowing the grid to quickly adapt to changing usage. They could also facilitate emergency deployment from a "strategic reserve" of critical devices, such as transformers.	Many standards already exist, but further work is needed.
Ultra high voltage lines	Higher voltage lines can carry more power than lower voltage lines. Higher voltages are possible, but require much larger right-of-ways, increase the need for reactive power reserves and generate stronger electromagnetic fields.	Voltage levels of 1 000 kV are currently used in Japan. Electromagnetic fields, right-of-way and technical concerns may limit use in other jurisdictions.
High-voltage DC (HVDC)	HVDC provides an economic and controllable alternative to AC for long-distance power transmission. DC can also be used to link asynchronous systems and for long-distance transmission under ground or water. Conversion costs from AC to DC and then back to AC have limited their usage.	Converter costs are decreasing making DC an increasingly attractive alternative. Most merchant transmission lines utilise HVDC.
Energy storage devices	Energy storage devices permit use of lower cost, off-peak energy during higher-cost peak-consumption periods. Some specialised energy storage devices can be used to improve power system control. Technologies include pumped hydro, compressed air, superconducting magnetic energy storage (SMES), flywheels and batteries.	Demonstrations are underway for many advanced storage technologies. The economics is problematic in most cases.

Sources: US DOE (2002); EPRI (2003b); EPRI (2003c); Gellings, C. (2004a); Hauer, J. et al. (2002); and IEA (2004b).

Table 8

Examples of Technologies with the Potential to Enhance Transmission System Security (Continued)

Technology	Description	Development status
Enhanced power device monitoring	The operation of many power system devices, such as transmission lines, cables and transformers is limited by the device's thermal characteristics. The high operating voltages of these devices make direct temperature measurement difficult. Lack of direct measurements requires conservative operation, resulting in less power transmission capacity and reduced operational flexibility. Newer dynamic sensors have the potential to increase transmission system capacity and operational flexibility.	Commercial units are available to measure conductor sag allowing for dynamic transmission line limits. Dynamic transformer and cable measurement units are also commercially available.
Direct system state sensors	In some situations, the capability of the transmission system is limited by region-wide dynamic constraints. Direct system voltage and flow sensors can be used to rapidly measure the system operating conditions, allowing for enhanced system control.	High-speed power system measurement units (eg phasor measurement units) are commercially available and are being used by several utilities. Research is progressing to examine use of these measurements for real-time control of the power system.
Enhanced system modeling	More accurate and dynamic modeling of transmission systems, employing methods such as probabilistic risk assessment, offers the potential for more flexible, real-time operational contingency planning and management of transmission system security.	Software programs are being developed that employ probabilistic methods for planning and system management. Planning tools have been developed and tested with several US utilities. Development is continuing.

Sources: US DOE (2002); EPRI (2003b); EPRI (2003c); Gellings, C. (2004a); Hauer, J. et al. (2002); and IEA (2004b).

Table 8

Examples of Technologies with the Potential to Enhance Transmission System Security (Continued)

Technology	Description	Development status
Enhanced system visualisation	Improved real-time visualisation of dynamic system operating conditions has the potential to substantially improve operators' situational awareness and capacity to respond to actual and potential emergency conditions.	On-line visualisation tools are being developed. One is currently being trialed by the Tennessee Valley Authority in the United States.
Enhanced data management	Improved methods of collecting, processing and sharing key data on the real-time status of integrated transmission systems can enhance system modeling and visualisation, enabling more effective planning and management of transmission system security.	Various protocols for common information management and data transfer have been developed and implemented. Work is progressing to develop more integrated communications system architectures.
Automatic control systems	Increasingly automated grid management designed to speed up reaction times for failure management.	Such systems are under development. Solutions for secure procedures are a major challenge.

Sources: US DOE (2002); EPRI (2003b); EPRI (2003c); Gellings, C. (2004a); Hauer, J. et al. (2002); and IEA (2004b).

Technology also has the potential to improve effective operator control over power flows, which would permit more flexible operation of transmission systems, allowing more effective real-time responses to alleviate congestion, manage emergency situations and enable timely service restoration. It may also support the development of more robust transmission systems that are able to continue to operate effectively even if regions within a larger integrated transmission system become disconnected – the so called 'self healing' transmission network. Technology also offers the potential to facilitate real-time co-ordination and more holistic management of transmission system security in transmission systems spanning multiple control areas. Such tools would greatly improve system operators' capacity to manage operational uncertainty.

Many technologies could be deployed to enhance transmission system security. Some examples are provided in Table 8.

Technologies can be combined to create integrated technological solutions with the potential to substantially improve transmission system security. Examples include combining technologies to create Wide Area Measurement Systems (WAMS), Flexible Alternating Current Transmission Systems (FACTS), and real-time visual reliability and risk monitors, such as the Community Activity Room (CAR). Box 4 provides an overview of these technologies.

Box 4 . Integrating Technologies to Improve Transmission System Security

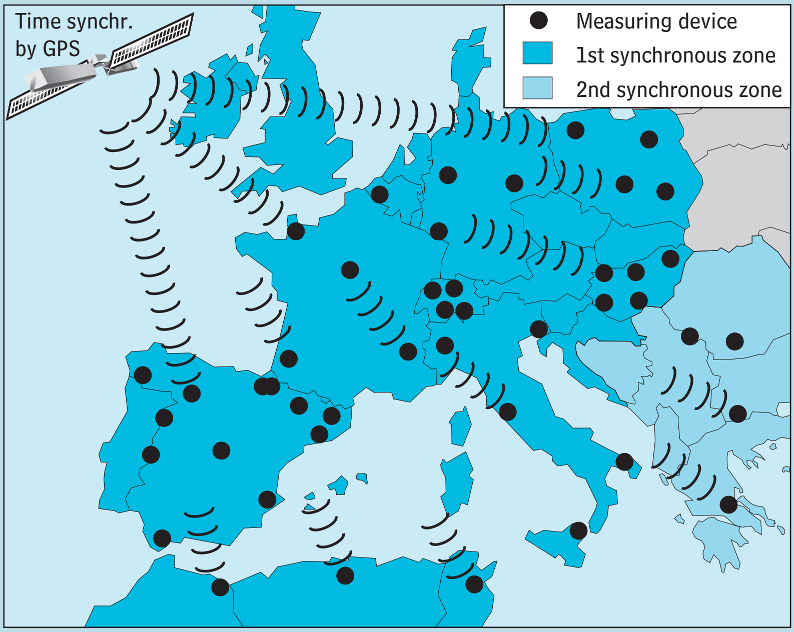
Wide Area Measurement Systems (WAMS)

WAMS technology is based on obtaining high-resolution power system measurements from sensors that are dispersed over wide areas of the grid, and synchronizing the data with timing signals from global positioning system satellites. System operators currently retrieve archived data to analyse grid disturbances and improve system models; in the future, they will be able to use these data in real time to assess the health of the grid.

The real-time information available from WAMS may allow operators to detect and mitigate a disturbance before it can spread and enable greater utilisation of the grid by operating it closer to its limits while maintaining reliability. The capacity that is freed up is available to move larger amounts of power over the grid in response to competitive market transactions.

Figure 28

UCTE Wide Area Measurement System



A prototype WAMS network was installed in the North American Western Interconnection in 1995, while a more extensive pilot WAMS system covering continental Europe was installed by UCTE members in 1998. Both systems have provided useful information in the context of analysing system disturbances. However, considerable potential exists to expand and enhance these systems to achieve their full potential.

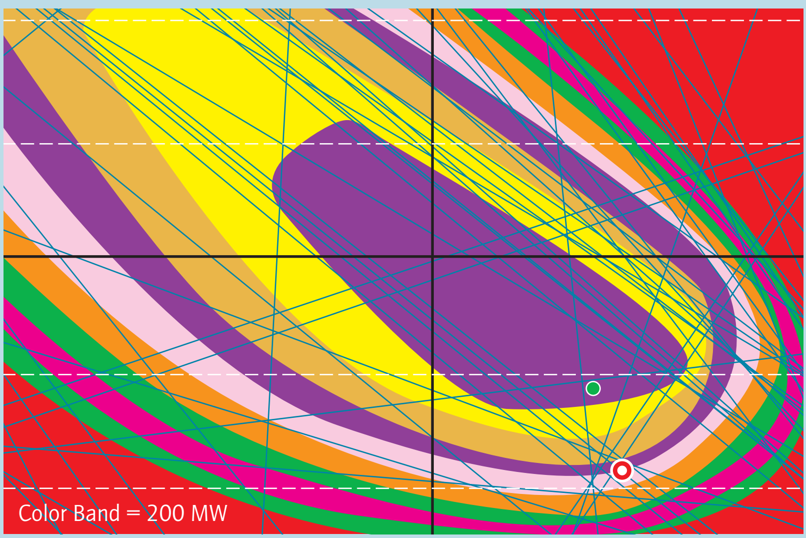
Flexible Alternating Current Transmission Systems (FACTS)

FACTS include a collection of electronic transmission power flow and control technologies that have extremely fast time response capabilities. FACTS devices are based on very high-power solid state electronic switches. They enable operators to exercise fast, precise and continuous active control of power flows on transmission systems to help relieve dynamic problems that may limit network use. FACTS also has the potential to increase the power-carrying capacity of individual transmission lines, providing an alternative to the construction of new transmission capacity.

FACTS provides the potential to react almost instantaneously to alleviate system congestion and manage power disturbances by providing real-time control of power flow on key lines. FACTS can also counteract transient disturbances, allowing transmission lines to be loaded closer to their thermal limits. Most FACTS applications remain very expensive, making FACTS uneconomic for most transmission applications at present. Quick response controllable load and distributed generation has the potential to permit more flexible and effective deployment of FACTS, particularly in the context of managing emergency events.

Figure 29

CAR Visualisation



Above is a CAR representation of a congested power grid where the "light bulb" (the red and white disc) has moved outside the "room". The position for getting back inside the "room" is given by the green disc.

Real-time System Visualisation Tools

The Community Activity Room (CAR) is a real-time dynamic visualisation display developed by EPRI. CAR converts the multidimensional transmission constraints for a transmission system into a three-dimensional set of equations that describe the 'walls' of a 'room' that represents the boundaries of reliable system operation imposed by transmission system security requirements. Beyond these 'walls' colour codes indicate probability risk of an outage and the degree of congestion.

Current operating conditions are shown by an illuminated point (or 'light bulb'). Operators monitor the location of the 'light bulb' and are warned when it approaches a 'wall'. If contingencies or market transactions move the 'light bulb' outside the 'walls', CAR shows the shortest path to move back inside the 'room'.

CAR is being tested by the Tennessee Valley Authority along with other EPRI software that together have the potential to turn CAR into an online probabilistic reliability monitor. This would allow system operators to understand the tradeoffs involved in operating their transmission systems in real time under a variety of conditions and how best to respond when system overloads or voltage violations occur.

Sources: US DOE (2002); UCTE (2004a); EPRI (2003b); EPRI (2003c); Hauer, J. et al. (2002); Burns, R., Potter, S. and Witkind-Davis, V. (2004); and Gellings C (2004b).

Strategic combinations of these technologies may offer additional synergies with the potential to further increase transmission system security. For example, WAMS could be combined with FACTS to provide system operators with more accurate real-time system monitoring capability to guide more effective deployment of flexible system control tools in response to dynamic changes in transmission system security. This would allow operators to more readily realise the potential of FACTS, while at the same time help increase the benefits from implementing WAMS[88]. More integrated deployment of technologies has the potential to facilitate a transformation of power delivery systems, improving their flexibility and resilience while enabling more innovative solutions to improve reliability, power quality and market efficiency[89].

Technology, however, should not be viewed as a 'magic bullet'. Increasing dependence on technologies also has the potential to increase vulnerability to technological failures. Technology failures in the North American case study contributed to a loss of situational awareness that was a direct cause of the blackout, while the spread of the failure reflected dependence on automatic controls. An appropriate balance between automatic and human control needs to be maintained, such that technology supports effective system operation and does not become a substitute for it.

Potential barriers to efficient development and deployment of cost-effective technologies may also need to be addressed. For instance, development and

88. *Hauer, J.* et al. *(2002).*

89. *Recent papers discussing these possibilities include Gellings, C. and Lordan, R. (2004); and EPRI (2003b).*

deployment of these technologies may suffer from being a shared responsibility, and a resource with some public good characteristics. An unbundled structure that encourages competition may not necessarily deliver the level of co-operation and co-ordination required through the value chain to achieve a timely and appropriate deployment. Uncertainty over relative roles and responsibilities in an unbundled environment and the potential to 'free ride' could exacerbate this challenge.

Other uncertainties may also discourage development and deployment. Unbundling leads to greater direct exposure to the related financial risks and costs. Greater competition, more effective regulation and greater exposure to legal liability in this environment may also discourage development and deployment of cost-effective technologies. In some cases it is possible that commercial interests would not be served by certain technological developments, which for example, may reduce network congestion permitting more trade and competition. These interests may act as a disincentive for such investment. Uncertainty over the potential benefits, costs and risks associated with the deployment of new technologies, particularly in relation to how new technologies will interact with existing technologies, may create a further disincentive for investment.

Regulation could also act as a barrier to efficient development and deployment of these technologies. For instance, regulatory incentives may generally focus on minimising costs at the expense of other activities, which may discourage investment in promising new technologies. There is also the potential that specific allowances for research and development or new investment may not be sufficient to enable timely deployment of cost-effective technologies.

Regulatory or institutional barriers to efficient development and deployment of cost-effective technologies need to be identified and removed to the greatest extent possible. Effective processes will be needed to test and validate new technologies, to help reduce uncertainty and deployment risks. Consideration might also be given to government assistance for promising areas of research and development, where appropriate. Any assistance should be provided in a framework of strong co-operation with industry to ensure that outcomes are efficiently and effectively deployed.

Investing in People

Skilled and experienced staff are essential for maintaining secure transmission system operation. Electricity market reform is creating a more dynamic operating environment, which on occasion requires immediate and incisive intervention to ensure continued, reliable and secure system operation. Highly trained and experienced personnel are required in this more demanding operating environment where transmission systems are run for longer periods at or close to their security limits. Technology cannot at this stage be expected to replace operator judgment and skill in managing transmission system security, particularly during emergency or near-emergency events.

The case studies illustrate the fundamental importance of effective system operation and the potential consequences of real-time operational decisions for transmission system security during emergency situations. In the Swiss-Italian event, for example, nine to ten minutes were used in an attempt to re-close the Mettlen-Lavorgo line even though it was not physically possible to do so given power flows on the system at that time. These minutes could have been spent exploring potentially more effective options.

Debate over the appropriateness of the system operator actions following the failure of the Mettlen-Lavorgo line highlights the importance of highly trained and experienced staff capable of quickly recognising developing emergency conditions and effectively intervening to either relieve the conditions, or to return the system to a secure operating state within prescribed timeframes[90]. The case studies suggest that scope may exist to strengthen operators' capacity to identify and respond to near and actual emergency events through appropriate training.

More attention has focused on emergency training in the wake of the 2003 blackouts. Training programmes are being implemented in North America with greater emphasis on emergency simulations to sharpen these skills. NERC requires staff with responsibility for the real-time operation or reliability monitoring of the bulk transmission system to undertake a minimum of five days of training and drills each year focusing on managing emergency events. Training programs must use realistic simulations. System emergency training is undertaken in addition to other training requirements[91].

Italian and Swiss system operators implemented a similar program in January 2004. Under this program, system operators train together for a week each year to help improve their ability to communicate and to co-ordinate responses to emergency events in real time. The program aims to facilitate an exchange of knowledge and experience between operators[92].

Nordel also undertakes joint annual training programmes to improve co-operation and to facilitate better co-ordination by improving operator

90. CRE and AEEG (2004).

91. NERC (2004e).

92. UCTE (2004a).

understanding of the characteristics of transmission systems in neighboring control areas. During these training programs system operators consider, among other things, operational issues relating to their shared management of transmission system security, including frequency regulation, managing power shortages and managing operational disturbances. Training employs case studies and uses desktop studies and computer simulators[93].

However, the more dynamic operating environment emerging with electricity market reform may suggest the need for a more fundamental review of current training programmes and practices. New training programmes may be needed to supplement experience, which may no longer be as relevant as it once was in the emerging more dynamic, real-time operating environment.

Nordel's Operation Committee recently noted that scope exists to improve its training programmes by adopting a more systematic approach to reviewing actual disturbances and applying simulators to emergency training. Potential exists to extend disturbance management training and to more effectively consider system restoration. A common certification process and training standards for new operators could also be considered to help operators develop a more holistic operational understanding of the integrated Nordic system[94].

In North America, NERC is also reviewing its training programs with a view to strengthening their effectiveness in a liberalised environment. A new operator training program is being developed and is scheduled for implementation in late 2005. Consideration is also being given to changing the basis for operator certification from a periodic assessment approach to a process of continual education and assessment[95].

Consideration could be given to reviewing the competencies needed to successfully manage transmission system security in liberalised electricity markets, and to examine whether current training and development programmes are sufficient to equip system operators for the more dynamic real-time operating challenges associated with electricity markets. Elkraft System is undertaking a competencies-mapping project to identify international best practices, new operator training requirements and opportunities for enhancing its operator training programmes.[96] Training to ensure that system operators more fully understand the nature and operation of electricity markets should be considered in this context.

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93. Nordel (2004b) and Hagman Energy AB (2005).

94. Nordel (2004b).

95. NERC (2005b).

96. Elkraft System (2004b).

Consideration could also be given to extending training to other relevant professionals involved in supporting secure system operation. These could include personnel managing related information technology and other technical or engineering staff. Training might also be extended to other parties whose actions could affect transmission system security, such as generator plant operators and technical regulators. NERC currently includes reliability co-ordinators in its operator training program.

Access to skilled staff could also become more of an issue in the future in some regions where an ageing workforce and progressive retirement of experienced people may create an experience and knowledge deficit, particularly among control room personnel. Such a loss of corporate memory and skill can have negative implications for effective management of transmission system security, particularly for the quality of real-time intervention to manage emergency events.

The US Department of Energy's National Transmission Grid Study notes that an ageing power system engineering workforce combined with an apparent decline in power system engineering graduates may lead to a shortage of qualified system operating staff in the future in North America. It notes concerns about the remuneration for power system engineers and suggests that higher pay in recognition of the more demanding operating environment may be required to attract new graduates[97].

Regulatory pressures on utilities to cut operating costs have the potential to exacerbate the situation if they are translated into an undue reduction in control room staff and resources for managing transmission system security[98]. This could have the effect of increasing pressure on remaining operating staff at a time when the challenges associated with managing transmission system security are rising as a result of the more dynamic operating environment created by electricity market reform. Increasing pressure and stress levels may increase the risk of operating errors, particularly during emergency situations.

Technical skill and staffing levels need to be carefully monitored, with appropriate action taken to identify and address any emerging deficits.

Asset Performance and Vegetation Management

Transmission system security is fundamentally dependent on predictable and reliable asset performance. Relatively small equipment failures can put

97. *US DOE (2002).*

98. Hauer, J., et al. *(2002) notes that regulatory cost-cutting pressures may have already led to a reduction in staffing levels and resources devoted to system planning.*

transmission system security at risk. Effective asset management is required to deliver predictable and reliable asset performance. Key dimensions of asset management in this context include protection and other operational settings that affect equipment performance, equipment maintenance practices and vegetation management practices. Each of these can exert a considerable influence on asset performance and transmission system security.

Management and Maintenance of Capital Equipment

The case studies highlight several examples of equipment that failed to operate as expected during emergency conditions and operated in a manner that helped to exacerbate the impact of the disturbance.

The US-Canada Power System Outage Task Force noted that unduly conservative protection settings on some generating equipment and transmission lines may have led to premature tripping of key generation and network assets, which accelerated the spread of the blackout and magnified its impact. Similar issues emerged during the Swiss-Italian event in relation to some of the initial generator trips.

The US-Canada Power System Outage Task Force also noted the failure of information technology equipment to function, or to function as expected, which served to degrade situational awareness among system operators and reliability co-ordinators, undermining a timely and effective emergency response.

In the Australian event, failure of protection devices to operate according to specification at the Bayswater and Eraring power stations tripped those generators and lead to substantial under-frequency load shedding[99].

In the Swiss-Italian and in the Swedish-Danish case studies, the failure of some generation to successfully migrate to in-house operation combined with the failure of some black-start generators to operate effectively under emergency conditions limited system operators' capacity to contain the impact of the event and slowed restoration.

Unavailability of generation and transmission assets for programmed maintenance can also temporarily reduce transmission system security by decreasing available resources to help manage emergencies while also placing a transmission system closer to its security limits. Maintenance issues can be expected to become more significant as loading on transmission systems increases. Several transmission lines and generators were unavailable due to

99. *NEMMCO (2005a).*

programmed maintenance during the Swedish-Danish event, reducing the resources available to help manage the emergency.

Effective maintenance programs are needed to meet these challenges. Scope may exist to apply more innovative maintenance practices. Transmission owners need to implement maintenance strategies that provide an appropriate balance between predictive and corrective maintenance. Predictive approaches using condition-based maintenance, for example, could be more fully utilised to target and optimise maintenance efforts, which could help to reduce maintenance down time while also minimising the risk of component failure at least cost[100]. Maintenance related risks to transmission system security could also be reduced by employing more integrated and co-ordinated maintenance cycles across integrated transmission systems. Nordel has proposed developing common procedures for co-ordinating planned transmission network outages[101]. Effective information exchange between transmission owners and operators will be required to support more integrated planned maintenance activities.

The case studies highlight the need for effective verification and enforcement to ensure that equipment is appropriately maintained and operates predictably, particularly during emergency situations. The degree of independence associated with verification and enforcement may also need to be considered in this context given the growing trend toward outsourcing of maintenance activities. Maintenance requirements and performance standards may need to be clarified.

Effective certification programs will help to strengthen verification and enforcement. Failure of contracted black-start generation in Denmark has led Elkraft System to implement new service contracts that incorporate routine and surprise inspections to test the preparedness of equipment contracted to provide black-start and other ancillary services. Incentive payments are linked to this verification program. Svenska Kraftnat is also reviewing its methodology and resource requirements to effectively manage outsourced maintenance, and is pursuing more effective enforcement of mandatory operational requirements for generators. NEMMCO has suggested that the legal framework underpinning system operation may need to be strengthened to provide it with authority to

100. Condition-based maintenance involves performing maintenance based on an assessment of the actual condition of components. It allows transmission owners to more closely align maintenance activities with observed wear and tear on equipment and probability of failure, to create more equipment-specific maintenance schedules designed to facilitate 'just in time' replacement. See Ray, C. (2004) and CIGRE (2005) for further discussion of innovative maintenance practices.

101. Nordel (2005a).

102. Elkraft System (2004b); Svenska Kraftnat (2004); and NEMMCO (2005a).

demand similar assurances from National Electricity Market generators that their plant can withstand credible contingencies[102].

Protection settings may also need to be reviewed to ensure that they provide an appropriate balance between equipment protection and reliable system operation. In particular, protection settings should not unduly contribute to the risk of a cascading blackout following an N-1 event. An initial review of Zone 3 transmission protection systems undertaken by NERC revealed that around 70% of those systems that did not meet operational requirements could be fixed by changing protection settings. NERC is continuing to examine the potential for wider and more effective use of protection systems to support reliable system operation[103].

Regulators should also be mindful of the potential impact of regulatory decisions on incentives for efficient asset management. For instance, there is potential for incentive regulation to encourage cost-cutting at the expense of effective maintenance. Regulatory outcomes need to allow adequate cost-recovery for prudent maintenance. These risks could be addressed though specific allowances for maintenance activities, possibly linked to some form of reliability performance incentive.

Another regulatory dimension may relate to decisions regarding mergers and acquisitions. The US-Canada Power System Outage Task Force recommended that regulators take into account the reliability implications of these decisions[104].

Vegetation Management

Vegetation management is arguably the most critical component of any transmission asset management program. It is generally accepted that a flashover or contact with vegetation represents one of the most likely causes of a transmission line failure. Hence, effective vegetation management is vital for maintaining transmission system security.

Vegetation management is the responsibility of transmission owners. Typically the rules governing vegetation management are more objective than prescriptive, leaving considerable scope for interpretation by transmission owners. Specific standards have generally not been prescribed in the past, in recognition of the need for flexibility to allow local transmission owners to adopt practices that are aligned to the nature and growth characteristics of local vegetation. Although some jurisdictions have adopted mandatory vegetation management standards, most are framed as guidelines and applied on a voluntary basis.

103. NERC (2005b).

104. United States-Canada Power System Outage Task Force (2004a).

Specific practices adopted to manage vegetation also vary considerably between transmission owners, reflecting the unique circumstances pertaining to each transmission line easement. However, they tend to share certain common features. Practices are typically built around a vegetation management cycle that involves the progressive assessment and treatment of all easements over a period of years. Recent reports found that vegetation management cycles in North America can take from one year to over ten years to complete, with cycles of around five years relatively common practice[105].

Inspection and assessment of transmission easements is generally undertaken using aerial surveys and ground patrols. Treatment can involve tree pruning or removal, and vegetation control in the immediate vicinity of facilities. Manual, mechanical and chemical methods are used to control vegetation along easements. Sometimes ground covers are planted in easements to help control the growth of other less desirable forms of vegetation. Transplanting is also undertaken on occasion. Inspections are commonly undertaken following treatment to assess the treatment's effectiveness. Vegetation management activities are sometimes supported by management systems such as vegetation inventories. Other activities can involve public education, and research and development. Vegetation management represents one of the largest recurring expenses for most transmission owners.

Ideally, vegetation management programs should be guided by the nature and rate of growth of the vegetation in and around each easement. However, the high cost of vegetation management combined with a common lack of rigorous analysis to support work programmes can expose vegetation management to expedient commercial decisions, particularly where transmission owners are under pressure to cut costs. As a result, work programmes can be curtailed or delayed for financial reasons.

Official investigations have raised concerns about the effectiveness of vegetation management standards and practices in the wake of the 2003 blackouts. Contact or flashover with vegetation was identified as a primary cause of the North American and Swiss-Italian blackouts featured in the case studies.

In the North American event, three key 345 kV transmission lines failed due to contact with vegetation. Each of these lines failed before reaching their emergency maximum thermal ratings, with one failing with power flows at around 44% of its maximum rating. The US-Canada Power System Outage Task Force concluded that these failures were caused by contacts or flashovers with trees under the transmission lines which had been allowed to grow too

105. Cieslewicz, S. and Novembri, R. (2004); and United States -Canada Power System Outage Taskforce (2004a).

tall rather than excessive conductor sag resulting from the overheating associated with large power flows. The Task Force recommended the establishment of enforceable standards for clearances in easements[106].

UCTE's investigation listed contact with trees as a primary cause of the Swiss-Italian outage but did not examine vegetation management practices, which were beyond the scope of its review. Vegetation management within the UCTE area is subject to national regulation. An investigation by the Swiss Federal Inspectorate for Heavy Current Installations of the transmission lines that tripped due to contact or flashover with vegetation during the Swiss-Italian event concluded that vertical clearances on these transmission lines had been maintained in accordance with the relevant standards and regulations. However, the Swiss Federal Office of Energy's investigation recommended that current standards be reviewed, particularly in relation to calculating conductor temperatures and the degree of sag associated with power flows[107].

Studies undertaken in the context of the North American blackout investigations have identified several best practices principles for vegetation management of transmission easements including[108]:

- **Management Framework**. Transmission owners should establish a formal vegetation management plan incorporating practices, objectives and approved procedures. The plan should include a documented work program and appropriate measures to ensure effective outcomes, such as a quality assurance programme. It should be revised periodically.
- Workload budgeting and scheduling should be based on accurate and current information about the vegetation under and adjacent to transmission lines. Appropriate information systems should be developed to support efficient and comprehensive vegetation management. Funding should be based on actual work requirements with flexibility to manage unanticipated events like removing a dead tree.
- **Operational Practices**. Field inspections of vegetation conditions should occur on a frequent basis, and the schedule should be based on anticipated growth. Aerial patrols should be complemented by regular ground patrols.
- Transmission easements should be maintained in accordance with 'wire zone-border zone' and integrated vegetation management strategies.

106. United States -Canada Power System Outage Task Force (2004a).

107. SFOE (2003).

108. Cieslewicz, S. and Novembri, R. (2004); and FERC (2004).

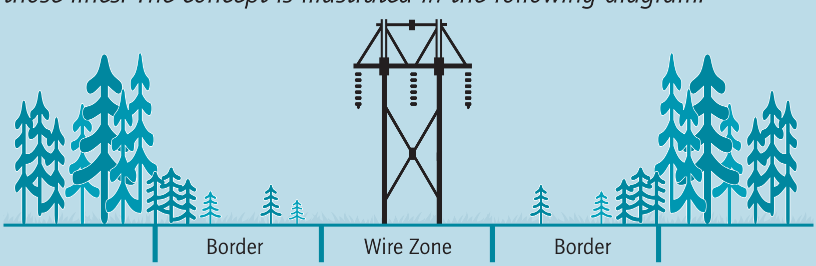
These practices employ environmentally sound control methods to promote desirable, stable, low-growing plant communities that will resist invasion by tall growing tree species. Figure 30 provides an overview of the 'wire zone-border zone' model.

- Maintenance of easements should take into consideration issues including line sag and sway, expected weather conditions and the anticipated pruning response of specific trees.
- **Qualifications and Education**. Transmission vegetation management programmes should be managed and implemented by appropriately qualified personnel. Internal training programmes should provide ongoing training for personnel directly involved with vegetation management. They should also aim to increase awareness and appreciation of vegetation management issues throughout a transmission owners organisation to promote support for these activities, particularly among senior management.
- Utilities should have a comprehensive public education programme that provides the public, individual landowners and other agencies and groups with accurate information regarding vegetation management activities and practices, to help increase support for effective vegetation management.

Figure 30

The Wire Zone – Border Zone Model

The wire zone-border zone model involves creating a predictable, low-growing vegetation environment immediately under and adjacent to transmission lines to prevent vegetation from growing into or falling on those lines. The concept is illustrated in the following diagram.



It has proven effective in reducing, and in some cases eliminating, vegetation-related outages on transmission easements. It can also generate other benefits including reduced long-term maintenance costs, improved habitat for wildlife, greater biodiversity and improved fire mitigation.

Sources: Cieslewicz, S. and Novembri, R. (2004); and FERC (2004). Diagram from Yahner, Bramble & Byrnes (2000).

- **Research and Development**. Transmission owners should undertake ongoing research and development to evaluate current and potential tools and practices.

Improved regulatory arrangements and more effective vegetation management practices offer the potential to significantly reduce the risk of vegetation-related transmission line outages. Several investigations have found that scope exists to create clearer, more consistent and enforceable vegetation management standards.

NERC is in the process of developing a more comprehensive vegetation management standard[109]. The current draft standard proposes minimum clearances and incorporates several of the best practice principles noted above. It appears that considerable discretion will remain for transmission owners to define the precise measures under the standard; however the framework for verification and compliance will be prescribed. The considerable variation that can occur in vegetation and climatic conditions precludes absolute prescription in this context. A balance will need to be struck between flexibility to accommodate local variations and certainty to permit effective verification and enforcement.

Mandatory standards alone are unlikely to eliminate vegetation-related transmission outages and, depending on their nature, may prove costly and difficult to enforce[110]. Standards need to be seen as part of the solution to improving vegetation management.

Other regulatory arrangements can also influence the effectiveness of vegetation management. FERC has noted that potential exists to improve regulatory co-ordination to remove potential duplication, resolve conflicting requirements and streamline regulatory approval processes. Vegetation management is an expensive exercise and regulators need to ensure that regulatory arrangements permit recovery of prudent expenditures. They also need to ensure that general incentives encouraging cost cutting are not translated into inappropriate cuts to vegetation management budgets[111].

Land owner and other local objections to effective, environmentally sound vegetation management may also need to be addressed. Education and effective communication combined with appropriate regulatory appeals processes could help to reduce resistance to appropriate vegetation management practices.

Adoption of improved vegetation management practices, including the best practice principles outlined above and shorter vegetation management cycles, would also help to increase the effectiveness of vegetation management programs.

109. NERC (2005a) and NERC (2005b).

110. Cieslewicz, S. and Novembri, R. (2004).

111. FERC (2004).

Applying Market-based Approaches to Support Transmission System Security

Electricity market reform is helping to strengthen transmission system security. Greater inter-regional trade resulting from reform has encouraged more efficient integration of transmission systems and permitted more effective reserve sharing arrangements within systems spanning multiple control areas. More effective integration has also expanded the potential pool of frequency control ancillary service providers in some regions, effectively increasing the resources available to help manage disturbances and emergency events from a frequency control perspective. A key benefit has been more cost-effective delivery of these services.

Some markets incorporate dynamic pricing of transmission congestion, such as locational marginal pricing, which is employed in several markets, especially in the Northeast of the United States. Dynamic congestion pricing provides greater transparency in relation to the operating state of a transmission system by time and location. It can create price incentives that are more closely aligned with the real-time operational conditions of a transmission system, encouraging market participants to respond in ways that support more efficient and cost-effective management of transmission system security. It can also help system operators to more effectively target system security resources to those transmission paths which are of greatest value to market participants.

Opportunities exist to strengthen transmission system security by employing more effective market-based mechanisms to improve transparency, strengthen cost-reflectivity and promote competitive service provision. Such mechanisms encourage more efficient, innovative and better-targeted provision of transmission system security at least cost. More transparent valuation of reliability and system security services may also provide a means of identifying and funding efficient new reliability-based investments, such as investments to provide reactive power.

Market-based approaches also encourage more flexible and responsive use of the transmission system, which has the potential to complement system operator management of transmission system security by reducing pressures on transmission resources at times when systems are congested and operating at or near their security limits.

Application of market mechanisms in these ways could enable more effective integration of network services with competitive markets, leading to more efficient and flexible provision of transmission system security reflecting market requirements. Markets may also provide a means of supporting more effective co-ordination of system security-related activities within the value chain and across transmission systems spanning multiple control areas, consistent with the shared nature of responsibility for transmission system security in unbundled electricity markets. Scope may exist to expand the role of market-based approaches to complement and, possibly in time, to replace regulatory methods for addressing transmission system security in some cases.

Markets for Ancillary Services

Ancillary services are required to ensure secure operation of transmission systems. They include a range of products to control frequency, voltage and power flows to ensure reliable delivery of electricity services. They also incorporate services to facilitate system restart after an outage, so called black-start ancillary services.

The potential benefits from employing market-based approaches to procure ancillary services have been recognised. At present, market-based methods typically involve open tendering and bilateral contracting processes. Some employ more dynamic market mechanisms that incorporate regular auction processes. Prices are set on the basis of competitive bids, with the marginal bid setting the system price for a particular trading period. In other cases, auction processes use cost-based regulated prices where competitive pressures are considered too weak to produce efficient system marginal prices. Cost recovery is typically averaged across users through some form of general charge or as part of the fixed component of transmission charges.

In the United Kingdom, ancillary services are provided through a combination of mandatory and commercial services. Commercial ancillary services are typically procured using market-based, open tender processes. National Grid Transco (the system operator) purchases a wide range of ancillary services through commercial processes including frequency control, network control and black-start services[112]. In some cases mandatory services have been replaced with commercially procured services by agreement between the contracting parties. Commercial arrangements have led to a substantial reduction in the overall cost of ancillary services for maintaining transmission system security.

The PJM Interconnection in the northeastern United States employs an auction-based approach to purchase regulating power and spinning reserve services[113].

112. Ancillary services that National Grid Transco currently procures through open tender processes include: maximum generation service, enhanced reactive services, commercial frequency response, fast reserve; standing reserve, warming; and emergency assistance. Further details are provided on the National Grid Transco website (http://www.nationalgrid.com/uk/).

113. PJM (2005).

Both the regulating and spinning reserve markets are cleared on a real-time basis and co-optimised with the energy market to minimise the total cost. The markets are cleared simultaneously so that a generating unit can only be selected to provide either regulating power or spinning reserve but not both.

PJM operates up to three regulating markets. Demand for regulating services is determined on the basis of technical requirements. Supply bids are accepted daily for each hourly trading period and can be modified on an hourly basis. In a market characterised by strong competition, the hourly price would be determined by the bid price of the marginal supplier, which would form the system marginal price received by all dispatched generators for a given trading period. However, the market is not considered sufficiently competitive to ensure efficient pricing outcomes at this stage. Hence, the market is currently cleared on the basis of administered prices that reflect the unit specific incremental cost plus a fixed opportunity cost margin per MWh supplied. These costs are calculated by PJM.

PJM introduced spinning reserve markets in December 2002, and operates up to three of these markets. Each market has two operational levels. Tier 1 resources consist of generating units that are online following economic dispatch and are able to increase output at short notice. All units within PJM are considered potential Tier 1 suppliers unless they are assigned to Tier 2, which includes units that are operated specifically to provide spinning reserve. Tier 1 units are paid when activated, while Tier 2 units are paid on the basis of their availability, whether or not they are used. An auction mechanism with an administered pricing regime similar to the one used for the regulating power market is employed to clear the spinning reserve market, as it is not yet considered sufficiently competitive for market-based bidding to set the price. PJM's Market Monitoring Unit undertakes market surveillance and advises PJM when administered pricing is required.

In Scandinavia, Nordel has operated a common real-time balancing market across the synchronous part of the Nordic region since September 2002. Nordel is investigating the potential for extending this market to include manually activated operating reserves, possibly from 2006[114].

Since November 2000, Statnett, the Norwegian TSO, has also operated an options market for fast-acting operational reserves. Under this arrangement, Statnett purchases an option to dispatch regulating resources from generators and from large consumers. Options are active for a trading period equal to one week. Bids of at least 25 MW can be made for periods of up to 8 weeks in

114. Nordel (2005b).

advance of a trading period and modified until the weekly gate closure (at noon on the Thursday before each trading week). Offers to reduce consumption by at least 25 MW must identify any restrictions regarding the period of activation and minimum interval between activations. Contracted reserves have to be offered to the balancing market between 6.00 a.m. and 10.00 p.m. each weekday during the trading period. Options that are activated must respond within 15 minutes.

Dispatch is determined by the bid-based merit order, subject to network capability, with the system marginal price set by the bid (offer) of the marginal generator (consumer) dispatched. All dispatched entities are paid the system marginal price. The reserves options market has proven effective and resulted in a substantial volume of demand-side participation from large industrial consumers. Statnett is investigating options to modify these arrangements to encourage participation from smaller consumers[115].

Further opportunities could be explored to extend market-based approaches for purchasing ancillary services. For example, market-based procurement could be expanded to include a wider range of ancillary services, such as more effective coverage of network control ancillary services like reactive power. Potential may also exist to use more dynamic market-based models, like the auction models noted above, which have the potential to substantially improve the flexibility and efficiency of transmission system security by more closely aligning resource procurement with real-time requirements. Another possibility may involve moving toward cost allocation based on the causer-pays principle rather then averaging costs across all users.

One notable example is the Australian Frequency Control Ancillary Services (FCAS) market, which was launched by the National Electricity Market Management Company (NEMMCO) in September 2001. NEMMCO purchases all its FCAS requirements for the National Electricity Market from this market. Eight products consisting of six contingency and two regulation services[116] are traded on the FCAS market. An auction mechanism is employed with the system marginal price determined by the bid of the marginal supplier for each product. Services are dispatched and settled on the same basis as the energy-only market, where bids are dispatched every 5 minutes with 30-minute settlement periods. This facilitates effective co-optimisation of the energy and

115. *Walther, B. and Vognild, I. (2005); and Nilssen, G. and Walther, B. (2001).*

116. *Contingency services are required to ensure that the large frequency deviations caused by relatively infrequent, large contingency events such as the unexpected loss of generating units or disconnection of large load blocks do not cause the frequency to deviate outside defined limits. Regulation services are used to carry out the continuous fine-tuning required to maintain frequency within the normal operating band. This fine-tuning is required to manage small deviations in load consumption and generation output.*

ancillary services markets. Small deviation costs are allocated on a causer-pays basis for each trading period. An overview of the FCAS market is provided in Box 5.

Box 5 . Overview of the Australian Frequency Control Ancillary Services Markets

The National Electricity Market Management Company (NEMMCO, the market and system operator for the Australian National Electricity Market) operates eight spot markets for frequency control ancillary services (FCAS). These include six markets for contingency services (6-second raise/lower; 60-second raise/lower and 5-minute raise/lower) and two markets for regulation service (raise/lower).

Dispatch

Registered service providers, including generation and load, can participate in the FCAS market by submitting an appropriate FCAS offer (load) or bid (generation) for that service, via NEMMCO's market management systems. An FCAS offer or bid submitted for a raise service represents the amount of MWs that a participant can add to the system, in the given time frame, in order to raise the frequency. An FCAS offer or bid submitted for a lower service represents the amount of MWs that a participant can take from the system, in the given time frame, in order to lower the frequency.

During each dispatch interval, NEMMCO's dispatch engine enables a sufficient amount of each of the eight FCAS products, from the FCAS bids and offers submitted, to meet the FCAS MW requirement. The dispatch engine will enable MW FCAS bids/offers in merit order of cost. The highest cost bid/offer to be enabled will set the marginal price for the FCAS category.

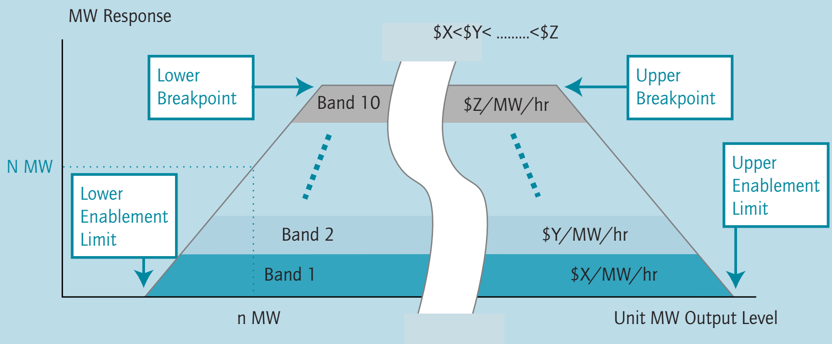
During periods of high or low demand, it may be necessary for the dispatch engine to move the energy target of a scheduled generator or load in order to minimise the total cost (of energy plus FCAS) to the market. This process is named co-optimisation and is inherent in the dispatch algorithm.

Offers and Bids

Offers and bids for the FCAS products take the form of the generic FCAS trapezium defined by enablement limits and breakpoints. The trapezium *indicates the maximum amount of FCAS that can be provided (y axis) for a given MW output level for a generator, or given MW consumption level for a scheduled load (x axis). For example, a generator or load dispatched, in the energy market, at "n" MW could be enabled by the dispatch engine to provide up "N" MW of the relevant FCAS.*

Figure 31

The FCAS Trapezium



The FCAS offers and bids must comply with similar bidding rules that apply to the energy market:

- *Bids or offers can consist of up to ten price-quantity bands with non-zero MW availabilities;*
- *Band prices must be monotonically increasing;*
- *Band prices must be set by 12.30 p.m. on the day prior to the trading day for which the bid or offer applies; and*
- *Band availabilities, enablement limits and breakpoints can be rebid under rules similar to those applying to the energy market.*

An ancillary services plant dispatched between an enablement limit and a corresponding breakpoint can be moved in the energy market in order to obtain more FCAS. For example, if a generator was dispatched between the upper enablement limit and the upper breakpoint, the dispatch engine may constrain the unit in the energy market in order to obtain more FCAS, provided this led to the lowest overall cost. The generic trapezium shown above is altered to suit the various technologies that provide FCAS.

NEMMCO is the sole purchaser of FCAS on behalf of market participants, and the costs are allocated to market participants on a causer-pays basis, where causers can be measured.

Settlements

For each FCAS market, clearing prices are set for each dispatch interval (5 minutes), to apply to all providers within a region. Prices are determined through the dispatch algorithm, and calculated to ensure that providers of both energy and FCAS are indifferent to the actual combination of energy and FCAS scheduled. That is, the prices for each FCAS service include an element of opportunity cost, to ensure providers are indifferent to using their equipment to provide either energy or FCAS. Payments to service providers are based on enablement of FCAS rather than actual use.

Settlement is determined on the basis of the normal 30-minute trading period. FCAS costs for each trading period equal the sum of the costs accrued for each 5-minute dispatch interval within the trading period.

All payments to FCAS providers are recovered from market participants. As contingency 'raise' requirements are set to manage the loss of the largest generator on the system, all payments for these three services are recovered from generators. On the other hand, as contingency lower requirements are set to manage the loss of the largest load/transmission element on the system, all payments for these three services are recovered from customers. Recovery for contingency services is pro-rated over participants based on the energy generation or consumption in the trading interval.

The recovery of payments for regulation services is based on the causer-pays principal. NEMMCO uses its supervisory control and data acquisition (SCADA) data to determine the contribution of each measured generator and load to frequency deviations for each dispatch interval. Causer-pays factors are calculated for each measured generator and load. Participants whose responses assist in the correction of frequency deviations are assigned a low causer-pays factor while those whose responses exacerbated the frequency deviation are assigned a high factor. Costs are recovered accordingly.

All non-measured entities (customers without SCADA) are assigned causer-pays factors based on the remainder (causers not accounted for by measured entities) and pro-rated based on their energy consumption in the trading interval being settled.

Sources: NEMMCO (2001); and ACCC (2001).

The National Electricity Code Administrator[117] reported that total FCAS costs fell from around AUD 110 million during the first full year of FCAS market operation (i.e. year ending September 2002) to around AUD 27 million during 2003-04, representing a reduction of around 75% in total annual costs over the period. The median weekly cost of FCAS in 2003-04 was around AUD 335 000, which represented around 0.5% of the total value of spot market turnover. The FCAS market is being refined to incorporate more effective regional cost allocation during periods when network congestion or disruptions separate the national market into its component regions.

Harnessing Demand Response

Demand-side participation has the potential to support more flexible, innovative and efficient delivery of transmission system security at least cost. Demand reductions in response to high prices tend to occur when transmission systems are operating close to their security limits. Effective harnessing of demand response in these situations has the potential to significantly reduce pressure on system security and improve reliability by improving the balance between generation and load. It would provide a more flexible and efficient alternative to mandatory load shedding during emergency situations. Greater demand flexibility may also reduce the volume of operating reserves system operators need to acquire to meet system security requirements. It may also be harnessed as an alternative source of operating reserve, helping to deepen the pool of reserves and increasing competition to provide reserve services. This could have the effect of lowering ancillary services costs while improving overall system security.

Greater demand flexibility may also support the development of markets that value reliability and system security. Such markets may open opportunities for the development of more flexible and innovative products and services to support transmission system security. In principal, they would also offer the potential to more closely integrate reliability with energy markets, providing a transparent price signal to help guide system operators toward more flexible and efficient management of system security that reflects consumers' valuation of reliability. They may also support the development of more efficient and dynamic methods for allocating transmission capacity for trade and reliability. Such markets could help complement existing regulatory measures to manage system security, and may have the potential to replace some of them over time. For instance, potential may exist to largely replace the use of mandatory load shedding with voluntary reductions based on some form of interruptible contract if sufficiently deep and competitive markets can be established.

117. NECA (2004).

The potential benefits of harnessing demand responsiveness to strengthen system security have been recognised. Typically these efforts have relied on administrative approaches such as demand management. Public appeals to voluntarily reduce consumption have also been used, particularly during emergency situations.

More effective market-based approaches are emerging. A variety of interruptible contracts with large industrial users are already used in North America, the United Kingdom, Scandinavia and Australia. Table 9 provides some examples of emergency load response programmes used in North America and the United Kingdom.

Probably the most substantial progress in harnessing demand responsiveness for system security to date has been made in the Nordic region and in the United Kingdom where significant amounts of demand response have been secured from large industrial users to provide regulating power reserves and operational reserves. An example from the Nordic market was described in the previous section. In the United Kingdom, National Grid Transco has attracted over 4 000 MW of demand response for frequency control and fast response operating reserves[118].

However, it is likely that considerable potential remains to be developed. Substantial voluntary demand reductions of up to 4 000 MW were recorded in Ontario during the emergency restoration phase following the 14 August 2003 blackout in response to public appeal[119]. Nordel has estimated the total potential demand response in the Nordic market at up to 12 000 MW, with every 1 200 MW of realised demand response having the potential to shave up to 2% off peak demand[120].

There are a range of potential barriers that may hinder the development of demand response for transmission system security. The real-time, instantaneous nature of system security management and the corresponding need for immediate responsiveness may practically preclude wider use of demand response beyond larger users. Technical and commercial arrangements used by system operators to procure operational reserves often tend to favour generation over demand, reflecting lower associated risks and transaction costs from a system operator's perspective, which may act as barrier to greater use of demand response[121].

118. IEA (2005).
119. IMO (2004).
120. Nordel (2005c).
121. IEA (2003).

Table 9

Examples of Emergency Load Response Programmes

Company	Programme	Minimum Size	Price Incentives	Financial Penalty
Independent Electricity Market Operator (Ontario)	Emergency Demand Response Programme	N.A.	Cost-reflective, real-time rate	None
US state utilities	Optional Binding Mandatory Curtailment Programme	15% reduction on entire circuit, in 5% increments	Exemption from rotating outages	USD 6 000 MWh of excess energy
PJM Interconnection (US)	Emergency Load Response Programme	100 kW	Higher of USD 500 MWh or zonal LMP	None
California Independent System Operator	Demand Relief Programme	1 MW load reduction	USD 20 000/MW-month and USD 500/MWh	Performance-based capacity payment
San Diego Gas & Electric	Rolling Blackout Reduction Programme	15% reduction from maximum demand, at least 100 kW	USD 200/MWh	None
New York Independent System Operator	Emergency Demand Response Programmes	100 kW reduction per zone (aggregated)	Greater of real-time price or USD 500/MWh	None

Source: IEA.

Verification of response is a critical issue in this context. Appropriate interval metering with remote telecommunications capability is necessary given the need to be able to precisely verify demand reductions in real time. Large industrial users typically possess appropriate metering; however, other users with potential to respond may not. Despite falling costs, installation of these meters remains relatively expensive and may limit further development of demand response for system security.

Efforts are being made to address some of these barriers and to expand the potential pool of demand response available to support system security. For instance, in the United States, the Federal Energy Regulatory Commission has proposed changes to market design rules to encourage greater demand response. In the United Kingdom, the system operator (National Grid Transco) is implementing new procurement guidelines with a view to engaging more demand-side participation[122].

Nordic TSOs have also proposed a range of action plans to enhance demand response, including improving its potential to contribute to system security[123]. These plans include:

- measures to enhance demand bidding for operational reserves and the balancing market;
- undertaking related research and development projects of common interest for market design and power system planning; and
- developing communication and information strategies to encourage market players and other stakeholders to become more active demand-side participants, or to take appropriate action to encourage further demand response.

These action plans will focus on encouraging greater demand-side participation among medium-sized industrial and commercial users, and in relation to the larger components of residential use, such as household electric heating.

Innovative financial products have the potential to support more effective harnessing of demand side participation. For instance, retail products could be developed that offer consumers differing degrees of service quality. Premium-priced products could offer minimum service interruption during power shortages or emergencies, with less expensive products involving greater exposure to service disruption during emergencies. Alternatively, products could be differentiated on the basis of compensation paid in the event of a service disruption.

122. IEA (2003).

123. Nordel (2005a); and Nordel (2005c).

Such products would allow customers to choose the level of service for which they are willing to pay. They could also be used to identify consumers that are more willing to experience service interruptions. This could support more efficient targeting of certain emergency interventions, such as load shedding, to protect system security at least overall cost to the community[124].

Another possibility involves encouraging more active participation from distributed generation. These generators are typically self-dispatching and tend to act like demand reduction from a system operation perspective. They are usually aggregated with demand in electricity market management systems. Nordic TSOs are investigating options to more effectively access and integrate distributed generation to deepen the market for system security services[125].

Some Challenges and Limitations

Although market-based mechanisms have considerable potential to help improve the flexibility and efficiency of transmission system security management, care needs to be exercised in their development and deployment in this context.

System security exhibits some characteristics consistent with a public good. For instance, the potential for system collapse may make operating reserves a public good where network users consider transmission system security external to their own activities and are therefore unwilling to pay for it. In these circumstances it is possible that a pure market solution may produce insufficient operating reserves to maintain system security[126]. Similar problems may emerge in relation to shared security services, such as frequency control, which can be provided at any point in an integrated transmission system. In transmission systems that span multiple control areas, there may be an incentive for individual system operators to 'free ride' to a degree on neighbouring system operators, relying on them to manage frequency deviations with their operating reserves. Were several system operators within an integrated transmission network to do this, then there is a risk that insufficient reserves may be procured in aggregate to meet credible system security contingencies[127].

The real-time nature of system security management may limit the application of market-based mechanisms. For instance, management of small deviations in voltage and frequency require immediate and largely automatic responses that

124. For further discussion of possible products built on the notion of 'priority insurance' see Giberson, M. and Kiesling, L. (2004).

125. See Chang, J., Murphy, D. and Graves, F. (2003) for further discussion of these issues.

126. See Joskow, P. and Tirole, J. (2004) for further discussion of this issue.

127. See Kirby, B. and Hirst, E. (2002) for further discussion of this issue.

would naturally preclude a market-based approach relying on price signals to ellicit responses. Models based on tenders or auctions that provide services for an agreed period would be better suited for providing such services.

Issues relating to the strength and depth of competition to provide services may also have implications for the deployment of market-based mechanisms. PJM's experience with market-based procurement of regulating and spinning reserves where the number of potential providers is relatively thin illustrates this point. Similar issues may emerge in the context of procuring services which are localised in nature, like reactive power. Reactive power rapidly diminishes over relatively short distances, which means that it must be provided close to source. As a result, it is likely that the underlying number of potential providers would be relatively small, possibly limited to just one or two suppliers in some cases, which might create potential for market power abuse[128]. Conversely, mandated provision combined with poor transparency may create a monopsony opportunity for system operators, as single buyers, to purchase these services below their market value. Regulation has the potential to intensify such behaviour where it creates inappropriate incentives for system operators to cut operating costs[129]. This could discourage efficient investment to provide reactive power in the longer term.

Effective market-based models rely fundamentally on the quality and timeliness of information. Information needs to be accurate over time and by location. Most importantly, it needs to be made available to all market participants quickly and transparently. This would be especially important with market models relying on near real-time responses to price signals, such as hourly auction models. Accurate information is also critical for effective verification of actions, which is particularly important for managing system security. It is also critical for effective regulation in this context. Effective real-time metering, information management systems and control equipment are required to meet this challenge. However, installation of these systems can be relatively expensive and coverage may therefore be limited to relatively few market participants. This could represent a practical barrier to deepening and broadening participation in the short term, particularly in the context of demand response as discussed previously.

Effective governance and regulatory arrangements that clearly assign authority and accountability would greatly assist the introduction of market-based mechanisms in this context. Related issues have been discussed in previous sections.

128. See Chang, J., Murphy, D. and Graves, F. (2003) for further discussion of these issues.

129. Giberson, M. and Kiesling, L. (2004).

These and other practical, technical and institutional issues need to be carefully considered in the context of developing and deploying market-based mechanisms and products to help manage transmission system security. The combination of these issues places some practical limitations on the potential to deploy market-based mechanisms and products at this time. Regulatory approaches will continue to be needed to ensure that transmission system security is not jeopardised. However, market-based mechanisms and products offer considerable potential to enhance and complement regulatory arrangements to strengthen transmission system security at least cost.

ANNEX 1

Annex 1

US-Canadian Power System Outage Task Force and NERC Investigation Recommendations and Implementation Status

Rec. Number		Description	Key Implementation Actions	Implementation Status
Task Force	NERC			
#1		Make reliability standards mandatory and enforceable, with penalties for noncompliance.	Energy Policy Act 2005 (EPA) implements provisions for the development and application of mandatory and enforceable reliability standards. The Federal Energy Regulatory Commission (FERC) issued a draft Notice of Proposed Rulemaking (NOPR Docket No. RM05-30-000) on 1 September 2005, which incorporates its proposals for establishing mandatory and enforceable reliability standards.	FERC to finalise rules by February 2006
#2		Develop a regulator-approved fundin mechanism for NERC and the regional reliability councils, to ensure their independence from the parties they oversee.	EPA provisions empower FERC to oversee and approve funding arrangements. FERC proposals are contained in its NOPR RM05-30-000 of 1 September 2005.	FERC to finalise mechanism by February 2006
#3		Strengthen the institutional framework for reliability management in North America.	EPA provisions provide for the establishment of an independent Electric Reliability Organisation (ERO) to develop and enforce reliability rules, subject to FERC regulatory supervision. Application across North America to be secured through international agreement between the US, Canada and Mexico. NERC has reformed its arrangements to make them consistent with the expected requirements for an ERO. FERC proposals are contained in its NOPR RM05-30-000 of 1 September 2005.	FERC to finalise criteria for EROs by February 2006

Sources: US-Canada Power System Outage Task Force (2004a); US-Canada Power System Outage Task Force (2004b); NERC (2005b) and FERC (2005).

Annex 1

US-Canadian Power System Outage Task Force and NERC Investigation Recommendations and Implementation Status (continued)

Rec. Number		Description	Key Implementation Actions	Implementation Status
Task Force	NERC			
#4		Clarify that prudent expenditures and investments for bulk system reliability (including investments in new technologies) will be recoverable through transmission rates.	FERC policy statement of 19 April 2004 reaffirmed its commitment to approve applications that recover prudent expenditures.	Complete
#5	#5	Track implementation of recommended actions to improve reliability.	NERC and regional reliability councils continue to track implementation and issue regular progress reports. NERC is developing arrangements for ongoing reliability performance monitoring.	Ongoing
#6		Confer FERC approval on new RTOs or ISOs only after they have met minimum functional requirements.	FERC policy statement of 19 April 2004 reaffirmed its commitment to take reliability issues into consideration before authorising new ISOs or RTOs.	Complete
#7		Require any entity operating as part of the bulk power system to be a member of a regional reliability council if it operates within the council's footprint.	EPA provisions empower an ERO to apply and enforce reliability standards with all relevant parties managing or using the bulk transmission system. FERC proposals are contained in its NOPR RM05-30-000 of 1 September 2005.	FERC to finalise rules by February 2006

Sources: US-Canada Power System Outage Task Force (2004a); US-Canada Power System Outage Task Force (2004b); NERC (2005b) and FERC (2005).

Annex 1

US-Canadian Power System Outage Task Force and NERC Investigation Recommendations and Implementation Status (continued)

Rec. Number		Description	Key Implementation Actions	Implementation Status
Task Force	NERC			
#8		Shield operators who initiate load shedding pursuant to approved guidelines from liability or retaliation.	No direct action to date. Could be addressed in context of strengthening institutional frameworks and prescribing reliability standards.	Not active
#9		Integrate a "reliability impact" consideration into the regulatory decision-making process.	FERC has created a reliability division to support assessment of reliability impacts.	Ongoing
#10		Establish an independent source of reliability performance information.	EPA provisions require the US DOE and FERC to report on establishing a system to provide real-time information on the functional status of all transmission lines within each interconnection.	Joint DOE/FERC report due by February 2006
#11	#15	Establish requirements for collection and reporting of data needed for post-blackout analyses.	NERC's Board of Trustees approved proposed standards for disturbance monitoring equipment and requirements for time-synchronised fault-recording devices in May 2005.	Ongoing
#12		Commission an independent study of the relationships among industry restructuring, competition and reliability.	DOE and Natural Resources Canada have initiated this study. EPA provisions require an Electric Energy Market Competition (EEMC) Task Force to report to Congress on competition issues.	Ongoing, EEMC Task Force to report by August 2006

Sources: US-Canada Power System Outage Task Force (2004a); US-Canada Power System Outage Task Force (2004b); NERC (2005b) and FERC (2005).

Annex 1

US-Canadian Power System Outage Task Force and NERC Investigation Recommendations and Implementation Status (continued)

Rec. Number		Description	Key Implementation Actions	Implementation Status
Task Force	NERC			
#13		Expand DOE's research programs on reliability-related tools and technologies.	DOE is working with NERC through the Consortium of Electric Reliability Technology Solutions on the development of these tools.	Ongoing
#14	#15	Establish a standing framework for the conduct of future blackout and disturbance investigations.	NERC developed blackout disturbance response procedures, including analysis requirements, which were accepted by the board in May 2005. Work to develop the procedures is proceeding. DOE has commissioned a report and work is progressing.	Progressing
#15	#1	Correct the direct causes of the 14 August 2003 blackout.	FE, MISO and PJM have undertaken remedial actions specified by NERC.	Complete, with some related ongoing activities
#16	#4	Establish enforceable standards for maintenance of electrical clearances in right-of-way areas.	NERC is in the final stages of developing a measurable standard that will specify the minimum clearances between energised high voltage lines and vegetation. EPA provisions will make minimum vegetation management standards mandatory and enforceable. NERC Reliability Regions submit annual reports on vegetation related line trips to NERC – first report was provided in March 2005.	New standard is expected by the end of 2005

Sources: US-Canada Power System Outage Task Force (2004a); US-Canada Power System Outage Task Force (2004b); NERC (2005b) and FERC (2005).

US-Canadian Power System Outage Task Force and NERC Investigation Recommendations and Implementation Status (continued)

Rec. Number		Description	Key Implementation Actions	Implementation Status
Task Force	NERC			
#17	#2	Strengthen the NERC Compliance Enforcement Programme.	NERC has implemented reforms to improve its compliance audit programme including updating compliance templates, disclosure of violators and reorganisation of its compliance committee. New guidelines for disclosure were adopted in June 2004. NERC is developing a methodology for ranking violations to guide the development of sanctions. EPA will help strengthen compliance and enforcement.	Largely complete; compliance enforcement programme subject to ongoing development
#18	#3	Support and strengthen NERC's Reliability Readiness Audit Programme.	Substantial progress has been made toward the goal of completing reliability audits for all reliability co-ordinators and control areas within 3 years. The 20 highest priority regions have been completed. NERC conducted reliability readiness audits of 61 control areas and 6 reliability co-ordinators during 2004. A further 55 entities are scheduled for audit in 2005.	Complete. Implementation ongoing
#19	#6	Improve near-term and long-term training and certification requirements for operators, reliability co-ordinators and operator support staff.	All reliability co-ordinators, control areas and transmission operators to provide 5 days of system emergency management training for system operators each year, with initial training completed by 30 June 2004. NERC is revising its operator training programme with new standards and accreditation requirements to be implemented shortly.	Ongoing; new training standards and accreditation to be implemented in 2005

Sources: US-Canada Power System Outage Task Force (2004a); US-Canada Power System Outage Task Force (2004b); NERC (2005b) and FERC (2005).

Annex 1

US-Canadian Power System Outage Task Force and NERC Investigation Recommendations and Implementation Status (continued)

Rec. Number		Description	Key Implementation Actions	Implementation Status
Task Force	NERC			
#20	#9	Establish clear definitions for normal, alert and emergency operational system conditions. Clarify roles, responsibilities, and authorities of reliability co-ordinators and control areas under each condition.	NERC has developed draft definitions. The draft is undergoing refinement. Once completed, it will be incorporated into the Reliability Co-ordinator Information System to improve consistency of communications between reliability co-ordinators.	Ongoing
#21	#8	Make more effective and wider use of system protection measures.Initial review of Zone 3 relay setting on 230 kV+ transmission lines completed in September 2004.	Regional Reliability Councils have completed initial reviews of the need for under-voltage load shedding. Final recommendations are expected in December 2005. NERC's review of protection and control standards is progressing.	Partially completed; follow-up work progressing
#22	#10	Evaluate and adopt better real-time tools for operators and reliability co-ordinators. NERC has established a Real-time Tools Best Practise Task Force focusing on identifying tools to improve situational awareness. Work should be completed by late 2005.	NERC is working with the Consortium for Electric Reliability Technology Solutions on an industry survey of best practices, and on the Eastern Interconnection Phasor Project. This program together with the Western Electricity Co-ordinating Council's Wide Area Measurement System, will include installation and assessment of high-speed measurement and analysis tools.	Ongoing

Sources: US-Canada Power System Outage Task Force (2004a); US-Canada Power System Outage Task Force (2004b); NERC (2005b) and FERC (2005).

Annex 1

US-Canadian Power System Outage Task Force and NERC Investigation Recommendations and Implementation Status (continued)

Rec. Number		Description	Key Implementation Actions	Implementation Status
Task Force	NERC			
#23	#7	Strengthen reactive power and voltage control practices in all NERC regions.	NERC has reviewed current practices. New and revised standards and procedures are being implemented. Regional studies are being undertaken into the feasibility of an under-voltage load shedding program. These studies are expected to be completed before 2006. Several regions have initiated processes to develop regional voltage control/reactive power criteria.	Ongoing
#24	#14	Improve quality of system modeling data and data exchange practices.	Reliability regions are reviewing their models, criteria and procedures for model validation and benchmarking. NERC is monitoring regional activities to improve modeling and data exchange. NERC has initiated a project to identify best practices and to propose recommendations for improving current standards and practices.	Ongoing
#25	#13a #13b #16	NERC should reevaluate its existing reliability standards development process and accelerate the adoption of enforceable standards.	NERC adopted new reliability standards in February 2005. Under the EPA, FERC will be required to review the reliability standards adopted by an ERO.	Complete
#26	#16	Tighten communications protocols, especially for communications during alerts and emergencies. Upgrade communication system hardware where appropriate.	NERC has adopted new protocols for hotline calls between reliability co-ordinators, and has installed new teleconference facilities. NERC is upgrading its real-time Reliability Co-ordinator Information System.	Ongoing

Sources: US-Canada Power System Outage Task Force (2004a); US-Canada Power System Outage Task Force (2004b); NERC (2005b) and FERC (2005).

US-Canadian Power System Outage Task Force and NERC Investigation Recommendations and Implementation Status (continued)

Rec. Number		Description	Key Implementation Actions	Implementation Status
Task Force	NERC			
#27	#13c	Develop enforceable standards for transmission line ratings.	NERC is developing a transmission facility ratings reliability standard. EPA provision will empower an ERO to enforce such standards.	Ongoing
#28	#12	Require use of time-synchronised data recorders.	NERC has received standards and current practices. New standards are being developed to improve disturbance monitoring capabilities. Criteria for selecting and locating disturbance recording devices are being developed with regional councils. Protocols for exchanging information are also being developed. FERC policy statement of 19 April 2004 reaffirmed its commitment to approve applications that recover prudent expenditures.	Ongoing
#29	#11	Evaluate and disseminate lessons learned during system restoration.	NERC regional reliability councils most affected by the blackout have prepared restoration reports, which have been circulated to members. Key recommendations from these investigations are being implemented. Ontario's IMO published its restoration evaluation report in February 2004. All NERC regions are reviewing their blackstart and system restoration plans and procedures in the light of these experiences.	Ongoing

Sources: US-Canada Power System Outage Task Force (2004a); US-Canada Power System Outage Task Force (2004b); NERC (2005b) and FERC (2005).

Annex 1

US-Canadian Power System Outage Task Force and NERC Investigation Recommendations and Implementation Status (continued)

Rec. Number		Description	Key Implementation Actions	Implementation Status
Task Force	NERC			
#30		Clarify criteria for identification of operationally critical facilities, and improve dissemination of updated information on unplanned outages.	NERC has enhanced its RCIS and system data exchange applications to improve dissemination of information on forced outages. Work is continuing on criteria for identifying and disseminating information on the operational status of other critical facilities. Joint DOE/FERC study about dissemination of real-time information on the functional status of all transmission lines is also relevant in this context (see Recommendation 10).	Ongoing
#31		Clarify that the transmission loading relief (TLR) process should not be used in situations involving an actual violation of an operating security limit. Streamline the TLR process.	NERC has revised its operating policies in relation to TLRs and incorporated changes into the latest reliability standards.	Complete
#32 #33 #34 #35	#17 #17 #17 #17	Implement NERC IT standards. Develop and deploy IT management procedures. Develop corporate-level IT security governance and strategies. Implement controls to manage system health, network monitoring and incident management.	NERC implemented a temporary cyber-security standard and procedures in August 2003. New permanent standards and procedures are being developed and are expected to be completed before 2006. Implementation will proceed in 2006. EPA will enable mandatory application and enforcement of standards.	New permanent standard is expected to be implemented in 2006

Sources: US-Canada Power System Outage Task Force (2004a); US-Canada Power System Outage Task Force (2004b); NERC (2005b) and FERC (2005).

Annex 1

US-Canadian Power System Outage Task Force and NERC Investigation Recommendations and Implementation Status (continued)

Rec. Number		Description	Key Implementation Actions	Implementation Status
Task Force	NERC			
#36	#17	Initiate US-Canada risk management study.	The US Department of Homeland Security, DOE, NERC and Public Safety & Emergency Preparedness Canada have jointly developed a security risk assessment methodology, which is being applied to specific infrastructure components. Several reviews have been completed.	Risk assessment methodology is complete; implementation is ongoing
#37	#17	Improve IT forensic and diagnostic capabilities.	Actions to identify and adopt best practices are an ongoing part of NERC operational practice.	Ongoing
#38	#17	Assess IT risk and vulnerability at scheduled intervals.	NERC has developed several security guidelines relating to process control systems (PCS) and Supervisory Control and Data Acquisition (SCADA) systems. Work is progressing to promote the development of new technologies to enhance security, safety and reliability of PCS and SCADA systems.	Ongoing
#39	#17	Develop capability to detect wireless and remote wireline intrusion and surveillance.	NERC has developed guidelines on cyber-security intrusion detection. The permanent standard will incorporate requirements for monitoring and controlling access.	Guidelines complete; development ongoing
#40 #41	#17 #17	Control access to operationally sensitive equipment. NERC should provide guidance on employee background checks.	NERC has developed and implemented the relevant security guideline.	Complete

Sources: US-Canada Power System Outage Task Force (2004a); US-Canada Power System Outage Task Force (2004b); NERC (2005b) and FERC (2005).

US-Canadian Power System Outage Task Force and NERC Investigation Recommendations and Implementation Status (continued)

Rec. Number		Description	Key Implementation Actions	Implementation Status
Task Force	NERC			
#42	#17	Confirm that NERC's Electricity Sector Information Sharing and Analysis Center is the central point for sharing security information and analysis.		Complete
#43	#17	Establish clear authority for physical and cyber security.	NERC's new cyber-security standards will address this issue. New permanent standards and procedures are being developed and are expected to be completed before 2006. Implementation will start in 2006.	New permanent standard is expected to be implemented in 2006
#44	#17	Develop procedures to prevent or mitigate inappropriate disclosure of information.	NERC has developed a security guideline addressing this issue. The permanent standards will include requirements for data and information to be classified according to confidentiality.	Complete
#45		Canadian Nuclear Safety Commission (CNSC) request Ontario Power Generation and Bruce Power to review operating procedures and operator training associated with the use of adjuster rods.	CNSC is responding through its licensing program.	Ongoing
#46		CNSC to purchase and install backup generation equipment.	Capacity was installed in August 2004.	Complete

Sources: US-Canada Power System Outage Task Force (2004a); US-Canada Power System Outage Task Force (2004b); NERC (2005b) and FERC (2005).

ANNEX 2

Annex 2

North American Electric Reliability Council Draft Functional Model

Function	Description	Key Tasks	Responsible Entity	Related Entities that serve or are served by the Responsible Entity
Operating Reliability*	Ensures the real-time operating reliability of the interconnected bulk electric transmission systems within a Reliability Authority Area.	• Enforce operational reliability requirements • Monitor all reliability-related parameters within the Reliability Authority Area, including generation dispatch and transmission maintenance plans • Direct revisions to transmission maintenance plans as required and as permitted by agreements • Request revisions to generation maintenance plans as required and as permitted by agreements • Develop Interconnection Reliability Operating Limits (to protect from instability and cascading outages). • Perform reliability analysis (actual and contingency) for the Reliability Authority Area • Approve or deny bilateral schedules from the reliability perspective • Assist in determining Interconnected Operations Services requirements for balancing generation and load, and transmission reliability (e.g., reactive requirements, location of operating reserves). • Identify, communicate, and direct actions to relieve reliability threats and limit violations in the Reliability Authority Area • Direct implementation of emergency procedures • Direct and coordinate System Restoration	Reliability Authority	• **Transmission Owners** • **Transmission Planners** • Transmission Operators • Transmission Service Providers • Generator Owners • Generator Operators • Load-serving Entities • Distribution Providers • Balancing Authorities • Interchange Authorities • Planning Authorities • External Reliability Authorities • ERO/NERC

Annex 2

North American Electric Reliability Council Draft Functional Model (continued)

Function	Description	Key Tasks	Responsible Entity	Related Entities that serve or are served by the Responsible Entity
Planning Reliability*	Ensures a long-term (generally one year and beyond) plan is available for adequate resources and transmission within a Planning Authority Area. It integrates and assesses the plans from the Transmission Planners and Resource Planners within the Planning Authority Area to ensure those plans meet the reliability standards, and develops and recommends solutions to plans that do not meet those standards.	• Develop and maintain transmission and resource (demand and capacity) system models to evaluate transmission system performance and resource adequacy. • Maintain and apply methodologies and tools for the analysis and simulation of the transmission systems in the assessment and development of transmission expansion plans and the analysis and development of resource adequacy plans. • Define and collect or develop information required for planning purposes • Evaluate plans for customer requests for transmission service. • Review and determine TTC values (generally one year and beyond) as appropriate. • Assess, develop, and document resource and transmission expansion plans. • Provide analyses and reports as required on the long-term resource and transmission plans for the Planning Authority Area. • Monitor transmission expansion plan and resource plan implementation. • Co-ordinate projects requiring transmission outages that can impact reliability and firm transactions. • Evaluate the impact of revised transmission and generator in-service dates on resource and transmission adequacy.	Planning Authority	• Transmission Owners • Transmission Planners • Transmission Operators • Transmission Service Providers • Generator Owners • Generator Operators • Load-serving Entities • Distribution Providers • External Resource Suppliers • Planning Authorities • Resource Planners • External Reliability Authorities

Annex 2

North American Electric Reliability Council Draft Functional Model (continued)

Function	Description	Key Tasks	Responsible Entity	Related Entities that serve or are served by the Responsible Entity
Balancing*	Integrates resource plans ahead of time, and maintains load-interchange-generation balance within a Balancing Authority Area and supports interconnection frequency in real time.	• Must have control of any of the following combinations within a Balancing Authority Area: Load and Generation (an isolated system); Load and Scheduled Interchange; Generation and Scheduled Interchange; or Generation, Load, and Scheduled Interchange. • Calculate Area Control Error within the Balancing Authority Area. • Review generation commitments, dispatch, and load forecasts. • Formulate an operational plan (generation commitment, outages, etc) for reliability assessment • Approve Interchange Transactions from ramping ability perspective • Implement interchange schedules by entering those schedules into an energy management system • Provide frequency response • Monitor and report control performance and disturbance recovery • Provide balancing and energy accounting (including hourly checkout of Interchange Schedules and Actual Interchange), and administer Inadvertent energy paybacks • Determine needs for Interconnected Operations Services • Deploy Interconnected Operations Services. • Implement emergency procedures	Balancing Authority	• Transmission Operators • Transmission Service Providers • Generator Operators • Load-serving Entities • Balancing Authorities • Interchange Authorities • Reliability Authority

Annex 2

North American Electric Reliability Council Draft Functional Model (continued)

Function	Description	Key Tasks	Responsible Entity	Related Entities that serve or are served by the Responsible Entity
Interchange*	Authorizes implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures Interchange Transactions are properly identified for reliability assessment purposes.	• Determine valid, balanced, Interchange Schedules (validation of sources and sinks, transmission arrangements, interconnected operations services, etc.). • Verify ramping capability of the source and sink Balancing Authority Areas for requested Interchange Schedules • Collect and disseminate Interchange Transaction approvals, changes, and denials • Authorize implementation of Interchange Transactions • Enter Interchange Transaction information into Reliability Assessment Systems (e.g., the Interchange Distribution Calculator in the Eastern Interconnection) • Maintain record of individual Interchange Transactions	Interchange Authority	• Transmission Service Providers • Purchasing-Selling Entities • Balancing Authorities • Reliability Authorities
Market Operations	Integrates energy, capacity, balancing, and transmission resources to achieve an economic, reliability-constrained dispatch of resources. The dispatch may be either cost-based or bid-based.	• Administer a market that provides capacity, energy, balancing resources, and other Ancillary Services subject to system requirements and constraints. • Arrange resources for congestion management. • Provide dispatch plans.	Market Operator or Resource Dispatcher (non-market environment)	• Market Operator tasks and relationships are specific to a particular Market Operator and will depend on the market structure over which the Market Operator presides. • A Resource Dispatcher performs the same dispatch duties as a Market Operator, but in a non-market environment.

Annex 2

North American Electric Reliability Council Draft Functional Model (continued)

Function	Description	Key Tasks	Responsible Entity	Related Entities that serve or are served by the Responsible Entity
Resource Planning	Develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority Area.	• Maintain resource models and apply appropriate tools for the development of adequate resource plans. • Define and collect or develop demand and resource information required for planning purposes. • Provide capacity resource information to planning and operating functions and service functions. • Assist in the evaluation of the deliverability of resources to customers. • Include consideration of generation capacity from resources both within and outside of the Planning Authority Area. • Develop and report, as appropriate, on its resource plans to others for assessment and compliance with reliability standards. • Monitor and report, as appropriate, on its resource plan implementation.	Resource Planner	• Transmission Owners • Transmission Planners • Transmission Service Providers • Generator Owners • Generator Operators • Load-serving Entities • Interchange Authorities • Planning Authority • Resource Planners • Reliability Authorities

Annex 2

North American Electric Reliability Council Draft Functional Model (continued)

Function	Description	Key Tasks	Responsible Entity	Related Entities that serve or are served by the Responsible Entity
Transmission Operations	Operates or directs the operations of the transmission facilities.	• Maintain reliability of the transmission area in accordance with Reliability Standards. • Provide detailed maintenance schedules (dates and times) • Adjust DC ties within the transmission area for those Interchange Transactions that include the DC tie in the transmission path • Maintain defined voltage profiles. • Define operating limits, develop contingency plans, and monitor operations of the transmission facilities. • Provide telemetry of transmission system information	Transmission Operator	• Transmission Owners • Transmission Service Providers • Generator Owners • Generator Operators • Distribution Providers • Planning Authorities • Reliability Authority
Transmission Planning	Develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority Area	• Maintain transmission system models (steady-state, dynamics, and short circuit) and apply appropriate tools for the development of transmission plans. • Define and collect transmission information and transmission facility characteristics and ratings. • Develop plans within defined voltage and stability limits and within appropriate facility thermal ratings. • Define system protection and control needs and requirements, including special protection systems (remedial action schemes), to meet reliability standards. • Determine total transfer capacity values as appropriate.	Transmission Planner	• Transmission Owners • Other Transmission Planners • Transmission Operators • Transmission Service Providers • Generator Owners • Generator Operators • Load-serving Entities • Distribution Providers

Annex 2

North American Electric Reliability Council Draft Functional Model (continued)

Function	Description	Key Tasks	Responsible Entity	Related Entities that serve or are served by the Responsible Entity
		• Notify others of any planned transmission changes that may impact their facilities. • Evaluate and plan for transmission service and interconnection requests beyond one year. • Develop and report, as appropriate, on its transmission expansion plan for assessment and compliance with reliability standards. • Monitor and report, as appropriate, on its transmission expansion plan implementation.		• Planning Authorities • Resource Planners • Reliability Authorities
Transmission Service	Administers the transmission tariff. Provides transmission services to qualified market participants under applicable transmission service agreements.	• Receive transmission service requests and process each request for service according to the requirements of the tariff. • Approve or deny transmission service requests. • Approve Interchange Transactions from transmission service arrangement perspective. • Determine and post available transfer capability values. • Allocate transmission losses (MWs or funds) among Balancing Authority Areas.	Transmission Service Provider	• Other Transmission Service Providers • Purchasing-Selling Entities • Generator Owners • Load-serving Entities • Interchange Authorities • Planning Authority • Reliability Authorities

Annex 2

North American Electric Reliability Council Draft Functional Model (continued)

Function	Description	Key Tasks	Responsible Entity	Related Entities that serve or are served by the Responsible Entity
Transmission Ownership	Owns and maintains transmission facilities.	• Install and maintain transmission facilities according to prudent utility practice. • Establish ratings of transmission facilities. • Develops interconnection agreements.	Transmission Owner	• Other Transmission Owners • Transmission Planners • Transmission Operators • Transmission Service Providers • Generator Owners • Load-serving Entities • Planning Authorities • Reliability Authorities
Distribution	Provides and operates the "wires" between the transmission system and the end-use customer.	• Provide the interface between the transmission system and the end-use customer. • Provide localised voltage reduction and load shedding as necessary.	Distribution Provider	• Transmission Planners • Transmission Operators • Load-serving Entities • Planning Authorities

Annex 2

North American Electric Reliability Council Draft Functional Model (continued)

Function	Description	Key Tasks	Responsible Entity	Related Entities that serve or are served by the Responsible Entity
Generator Operation	Operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services.	• Operate generators to provide energy or Interconnected Operations Services (or both) per contracts or arrangements. • Formulate daily generation plan. • Report operating and availability status of units and related equipment, such as automatic voltage regulators. • Develop annual maintenance plan for generating units and performs the day-to-day generator maintenance.	Generator Operator	• Transmission Operators • Purchasing-Selling Entities • Load-serving Entities • Balancing Authorities • Planning Authorities • Resource Planners • Reliability Authorities
Generator Ownership	Owns and maintains generating units.	• Establish generating unit ratings, limits and operating requirements. • Maintain generation facilities according to prudent utility practices. • Verify generating unit performance characteristics.	Generation Owner	• Transmission Planners • Transmission Operators • Purchasing-Selling Entities • Load-serving Entities • Planning Authorities
Purchasing-Selling	Purchases or sells energy, capacity and all necessary Interconnected Operations Services as required. Purchasing-Selling Entities may be Marketers or Merchant Affiliates.	• Purchase and sell generation or capacity. • Arrange Interchange Transactions . • Arrange for transmission service (as required by tariffs). • Purchase and sell Interconnected Operations Services. • Request implementation of Interchange Transactions.	Purchasing-Selling Entity	• Transmission Service Providers • Generator Owners • Generator Operators • Other Purchasing-Selling Entities • Load-serving Entities • Interchange Authorities

Annex 2

North American Electric Reliability Council Draft Functional Model (continued)

Function	Description	Key Tasks	Responsible Entity	Related Entities that serve or are served by the Responsible Entity
Load-Serving	Secures energy and transmission service (and related Interconnected Operations Services) to serve the end-use customer.	• Collect individual and develop overall load profiles and forecasts of end-user energy requirements. (daily, weekly, monthly, annually etc...). • Identify and provide facilities for load curtailment. • Identify and provide facilities for self-provided Interconnected Operations Services. • Negotiate agreements for needed energy, transmission service, and Interconnected Operations Services. • Manage resource portfolios to meet demand and energy requirements of end-use customers.	Load-Serving Entity	• Transmission Planners • Transmission Operators • Transmission Service Providers • Generator Owners • Generator Operators • Purchasing-Selling Entities • Distribution Providers • Market Operator • Balancing Authorities • Planning Authorities • Resource Planners
Compliance Monitoring	Monitors, reviews, and ensures compliance with Reliability Standards and administers sanctions or penalties for non-compliance to the standards.	• Audit and document compliance of all registered Responsible Entities to Reliability Standards. • Recommend sanctions or penalties for non-compliance with Reliability Standards.	Compliance Monitor	• All Responsible Entities

Annex 2

North American Electric Reliability Council Draft Functional Model (continued)

Function	Description	Key Tasks	Responsible Entity	Related Entities that serve or are served by the Responsible Entity
Standards Development	Develops, maintains, and implements Reliability Standards to ensure the reliability of the interconnected bulk electric transmission systems. In North America this would include the United States, Canada, and Baja California Norte, Mexico.	• Develop Reliability Standards for the planning and operation of the interconnected bulk electric transmission systems that serve the United States, Canada, and Baja California Norte, Mexico. • Develop compliance measurement and enforcement procedures for each Reliability Standard. • Develop Criteria and Certification Procedures for Balancing, Interchange, and Reliability Authorities, Transmission Operators, and others as needed. • Provide for appeals and dispute resolution procedures.	Standards Developer	• Coordinates with other standards approving entities.

* = Functions NERC considers especially critical for reliability, including transmission system security.

Key Definitions:

Authority. The highest level of responsible entity for a particular function. The Reliability Authority is the highest level of all responsible entities.

Balancing Authority Area. The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.

Customer. A Purchasing-Selling Entity, Generator Owner, Load-Serving Entity, or End-user.

End-use Customer. The customer served by a Load-Serving Entity.

Function. A group of tasks that can not be logically subdivided into other groups.

Planning Authority Area. That area under the purview of the Planning Authority. It will include one or more Transmission Planning Areas.

Reliability Authority Area. The collection of generation, transmission, and loads within the boundaries of the Reliability Authority. Its boundary coincides with one or more Balancing Authority Areas.

Responsible Entity. The label that NERC applies to an organisation that is responsible for carrying out the tasks within a Function.

Task. One of the elements that make up a Function in the Functional Model.

Total Transfer Capacity (TTC). This refers to the amount of electric power that can be moved or transferred reliably from one area to another area of an interconnected transmission system by way of all transmission lines (or paths) between those areas under specified system conditions.

Transaction. An agreement arranged by a Purchasing-Selling Entity to transfer energy from a seller to a buyer.

Transmission Arrangements. An agreement between a Transmission Service Provider and Transmission Customer (Purchasing-Selling Entity, Generator Owner, Load-Serving Entity) for transmission services.

Transmission Planning Area. That area under the purview of the Transmission Planner.

Source: NERC (2004b).

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