

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

NERC Operating Manual

August 2016

RELIABILITY | ACCOUNTABILITY



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A History of NERC

1962 — The Interconnected Systems Group (ISG), comprised of utilities located in the Midwest and South, met to prepare for the imminent closure of seven interconnections to form the largest synchronized system in the world. The systems to be included were the four regions of the ISG (Northeast Region, Southeast Region, Northwest Region, and Southwest Region), Pennsylvania-New Jersey-Maryland Interconnection, and Canada-U.S. Eastern Interconnection (CANUSE). The Interconnection Coordination Committee (ICC) was formed to study and recommend an informal operations organization for the future. The North American Power Systems Interconnection Committee (NAPSIC) was formed that adopted the recommendations of the ICC. It served as an informal, voluntary organization of operating personnel that included the ISG regions, the four areas that now comprise WSCC, and ERCOT.

1965 — A blackout occurs in the northeastern United States and southeastern Ontario, Canada.

1967 — The U.S. Federal Power Commission report on the blackout recommended “A council on power coordination made up of representatives from each of the nation’s Regional coordinating organizations to exchange and disseminate information on Regional coordinating practices to all of the Regional organizations, and to review, discuss, and assist in resolving matters affecting interregional coordination.”

— Legislation proposed: Electric Power Reliability Act of 1967

1968 — Twelve Regional and area organizations form the National Electric Reliability Council (NERC) when they sign an agreement on June 1. On August 19, the chairman of the NERC Executive Board writes to the NERC Regions appointing an ad hoc committee on operations and an ad hoc committee on planning and coordination to study and recommend the need for other committees for NERC.

1970 — NERC opens its administrative office in New York City on January 1, and in May, moves to Princeton, New Jersey.

Four organizations in the Southeast combine to form the Southeastern Electric Reliability Council. NERC now has nine Regional Councils.

1975 — NERC incorporates as a nonprofit corporation in New Jersey.

1978 — The Board of Trustees agrees on several additional organizational objectives for NERC, including the need to: define and measure reliability, analyze and testify about legislation affecting reliability, study interregional interconnections, communicate with and educate others about reliability, and collect and publish data on future electricity supply and demand.

1979 — NERC assumes responsibility for collecting and analyzing generator availability data from the Edison Electric Institute’s (EEI) Prime Movers Committee. NERC, with support from the Electric Power Institute, restructures EEI’s Equipment Availability Data Reporting System to create the Generating Availability Data System (GADS).

NERC approves expanding its activities to address changes in the industry resulting from the passage of the U.S. National Energy Act of 1978. These activities include the development of planning guides for designing bulk electric systems, invitations to utility trade groups to send observers to NERC Board meetings, and adding staff to support expanded technical activities.

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1980 — The North American Power Systems Interconnection Committee merges with NERC and becomes the NERC Operating Committee. The NERC Technical Advisory Committee (TAC) becomes the NERC Engineering Committee.

1981 — To recognize the Canadian membership in the Regional Councils, NERC changes its name to North American Electric Reliability Council, keeping the acronym NERC.

1983 — Alaska Systems Coordinating Council becomes NERC's first affiliate member.

1986 — EEI transfers the integrated Hourly Load Data Base to NERC. NERC expands the database to include all ownership sectors of the electric utility industry.

1987 — At the urging of the U.S. government's National Security Council and Department of Energy, NERC forms the National Electric Security Committee to address terrorism and sabotage of the electricity supply system.

1990 — Congress passes the Clean Air Act Amendments of 1990. NERC uses the GADS database to provide the Energy Information Administration with a summary of forced and planned outages in the 1985–87 period. EPA uses the GADS data to set generator unit emission allocation values.

1992 — Congress passes the Energy Policy Act of 1992. The “NERC Amendment” in the Act bars the federal government from ordering transmission service if the order “would unreasonably impair the continued reliability of electric systems affected by the order.”

1993 — The Future Role of NERC Task Force, appointed by the Board of Trustees in 1992 to address provisions of the Energy Policy Act of 1992, develops an action plan for the future. The resulting report, *NERC 2000*, includes: Policies for Interconnected Systems Operation, Policies for Planning Reliable Bulk Electric Systems, Membership Recommendations, and Policies for Dispute Resolution.

1994 — Legislative and regulatory initiatives directed at the industry encourage competition through participation in the electricity marketplace by many new entities. The Regional Councils open their memberships to these new participants including independent power producers, power marketers, and electricity brokers. The NERC Board adds two voting Trustees positions for independent power producers.

NERC develops a set of principles for scheduling electricity interchange transactions — “Agreements in Principle on Scheduled Interchange” — that apply equally to electric utilities, power marketers, and other purchasing-selling entities.

1995 — The Federal Energy Regulatory Commission issues its Notice of Proposed Rulemaking (NOPR) on Open Access seeking comments on proposals to encourage a more fully competitive wholesale electric power market. NERC took the lead in addressing the planning and operating reliability aspects of the NOPR and filed a six-point action plan to provide the basis for action by the electric utility industry and FERC.

1. Establish standards for “Available Transfer Capability,”
2. Reflect actual path flows in interchange scheduling to ensure continued reliability,
3. Ensure control area operators have clear authority in emergencies,
4. Ensure compliance with NERC rules in a comparable and fair manner,
5. Establish standards for Interconnected Operations Services, and

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6. Ensure that information vital to operational security is shared freely among control areas, but is not available to gain unfair market advantage.

1996 — NERC opens its board and committees to voting participation by all industry segments, including power marketers and independent power producers.

1997 — NERC formed the Electric Reliability Panel, an independent body, to recommend how NERC should redefine its vision, functions, governance, and membership to ensure that reliability could be maintained in an increasingly competitive marketplace. The panel's report called on NERC to restructure itself into a new organization called the North American Electric Reliability Organization (NAERO) that could function as a self-regulating organization with the authority to set, measure, and enforce reliability planning and operating standards.

The board approved NERC's first Planning Standards, replacing Planning Guides and a "due process" for developing Operating Standards.

NERC developed two coordinated programs to establish standards for the training and qualifications of persons who operate the bulk electric systems of North America — System Operator Certification Program and System Operator Training Accreditation Program. NERC and Commercial Practices Working Group (an industry group addressing electricity marketplace issues) and NERC Regional Reliability Coordinators worked together to build a more viable and reliable marketplace. The Operating Committee put into place a Transaction Information System that provides a method for "tagging" all interchange transactions. The tag provides information to identify and track the purchase and sale of electricity so that the reliability of the system can be maintained.

1998 — NERC board approved the basic elements of a mission and purpose statement for NAERO, defined the composition of NAERO's board, and set forth NAERO membership requirements. It also approved key elements of agreements between NAERO and its affiliated Regional Reliability Organizations and approved formation of an Interim Market Interface Committee to review NERC reliability policies and standards for impacts on commercial markets. This committee is now called the Market Committee. The board voted in favor of consensus legislative language, which would permit NERC to become a self-regulatory organization. In addition, NERC agreed, at the request of the U.S. Deputy Secretary of Energy, to lead the electric industry's efforts to assess and report on the industry's readiness to deal with Y2K issues.

1999 — NERC elected nine independent members to the Board of Trustees to succeed the industry stakeholder board after reliability legislation was enacted in the United States. It also appointed a special steering committee to develop an action plan to implement the next steps in the process of enacting the NERC Consensus Legislative Language on Reliability. Other actions taken:

1. NERC coordinated the electric utility industry's preparations for the Year 2000 (Y2k).
2. The board disbands the old standing committee and created three new standing committees whose members represent all sectors of the industry
3. NERC initiated standards and compliance procedures and launched a pilot compliance program. Objectives were to test the effectiveness of NERC and Regional compliance review procedures and to test compliance with 22 NERC standards and their associated measurements.
4. NERC initiated a second-generation (electronic) tagging system to avoid problems inherent in email systems and protocols.
5. NERC certified almost 2,400 system operators under its System Operator Certification Program, which tested their understanding of NERC Operating Policies. By 2001, all system operators on duty had to be NERC-certified.
6. NERC initiated a new approach to project management. NERC staff would provide technical support

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and project management to implement the decisions and directives of the respective standing committees.

7. NERC released its *Study on NO_x Rule*, which assessed the potential impact of certain Clean Air Act requirements in the on bulk electric system reliability.

2000 — NERC agreed to serve as the electric utility industry’s primary point of contact with the federal government for issues relating to national security and critical infrastructure protection. As part of this effort, NERC became a founding member of the Partnership for Critical Infrastructure Security (PCIS), which coordinates cross-sector initiatives and complements public/private efforts to promote and assure reliable critical infrastructure services. NERC also significantly increased its outreach to government officials in both the United States and Canada, reflecting the critical role governments play in the restructuring of the electric utility industry. In addition:

1. NERC and FERC take major step toward improving coordination and communication between the two organizations with the execution of a “Consultation and Communications Protocols,” which calls for increased FERC participation at NERC board and committee meetings and periodic discussions between the FERC chairman and NERC executives
2. NERC sponsored a long-term planning initiative to address market-reliability interface issues. The issues identified were molded into action plans and approved by the board.
3. Control Area Criteria Task Force defined basic operating reliability functions that can be rolled up into other entities. The concepts discussed in its report will serve as the basis for new operating policies and standards.
4. Board charged the Standards Task Force with recommending changes to the NERC reliability standards and the process used to develop them.
5. NERC Compliance Enforcement Program (CEP) completed the second year of a multi-year phase-in.

2001 — In the absence of legislative authority, nine of the ten Regional Reliability Councils signed an Agreement for Regional Compliance and Enforcement Programs with NERC. The agreements are intended to enforce compliance with NERC reliability rules through contractual means. Although the Agreements are not a substitute for federal legislation, they allow NERC to ensure some measure of compliance with some of the rules.

The NERC board revised its bylaws to change its governance to a ten-member Independent Board of Trustees from a 47-member Stakeholder Board, despite the fact that Congress failed to adopt proposed reliability legislation.

NERC passed several resolutions to approve a functional operating model, ensure the independence of the reliability coordinators, and initiated a transition to organization standards.

1. NERC Operating Committee designed a model that defines the basic functions for reliable bulk electric system operations. With these functions defined, NERC can write standards to address each of function. Then, as new organizations, such as regional transmission organizations (RTO), independent system operator (ISO), and independent transmission companies, develop, they will register the functions they perform with NERC as well as the standards that they will need to comply with.
2. The NERC Compliance Enforcement Program completed audits of all Reliability Coordinators (RCs) by the end of 2000 focusing on all aspects of RC responsibilities
3. NERC developed a series of new control area criteria, operating policies, and planning standards. The control area criteria establish the requirement for qualification as a NERC-certified control area.
4. The Standards Task Force (STF) was established to redesign the process by which NERC standards are developed. NERC will use the new standards development process to prepare new organization standards.

2002 — NERC continued to work to improve the electric industry's physical and cyber security and to provide a common point for coordination with the U.S. government by forming the Critical Infrastructure Protection Advisory Group. The Group developed a compendium of security guidelines for the electricity sector for protecting critical facilities against a spectrum of physical and cyber threats and established the Electricity Sector Information Sharing and Analysis Center.

It also established a Critical Spare Equipment Database, replacing a smaller, limited database and with support from the U.S. Department of Energy is designing a standardized public key infrastructure implementation plan for the industry. NERC also designed and implemented a new reliability standards development process for the industry.

1. NERC-NAESB Coordination. NERC is responsible for developing reliability standards, while the North American Energy Standards Board (NAESB) develops business practice standards and electronic communications protocols for the wholesale electric industry. In recognition of the close relationship between reliability standards and business practice standards, NERC and NAESB signed a memorandum of understanding that details the coordination between the two organizations. A Joint Interface Committee (JIC), comprising representatives of NERC and NAESB, was created to examine each standard proposal that is submitted to NERC or NAESB to determine which organization should develop the standard.
2. Organization Certification. The functional model identifies the functions that need to be performed to ensure the reliable planning and operation of the grid. Some of the entities that expect to perform these functions will need to be certified, similar to the way control areas are certified today. The new reliability standards will identify reliability responsibilities along with the certification requirements for these functions.
3. Personnel Certification. The System Operator Certification Program was expanded to offer four credentials for specialized testing in the following areas: balancing and interchange, transmission, balancing/interchange and transmission, and reliability coordinator. The program provides enhanced individual utility training, self-study workbooks, computer training programs, and support workshops. To date, more than 4,300 individuals have attained a NERC certification credential.
4. Reliability Coordinator Audits. By the end of 2002, the Compliance Enforcement Program (CEP) had audited all NERC Reliability Coordinators. The audits focused on all aspects of the Reliability Coordinator responsibilities. Overall, the audit teams found that Reliability Coordinators are acting effectively and independently to preserve the reliability of the bulk electric system.
5. NERC, in conjunction with the Consortium for Electric Reliability Technical Solutions (CERTS), developed and implemented an area control error (ACE) and an area interchange error (AIE) real-time monitoring system applications for North America. These applications enable the reliability coordinators to monitor ACE-frequency performance and compliance with performance operational guides as well as allow NERC to analyze and assess control data to improve reliability performance.
6. Assuring the reliability of new generator connections. FERC issued a NOPR on Standardization of Generator Interconnections that included a draft agreement designed to standardize and streamline the generator interconnection process. NERC filed comments suggesting that further work is required to ensure that the reliability requirements outlined in the NOPR are consistent with NERC reliability standards and not affect the reliability of the bulk electric system.
7. NERC board approves and implements a new process for developing reliability standards. A Standards Authorization Committee is created and a NERC standards director is appointed.

2003 — NERC board adopted two more electric sector critical infrastructure protection security measures dealing with securing remote access to electronic control and protection systems and threat and incident reporting. The board adopts the first standard to emerge from the new standards development process.

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1. The new reliability standards development process receives ANSI-accreditation.
2. NERC receives and process 18 standard authorization requests. Several standards move into the development phase.
3. NERC adopts a cyber security standard, the first standard to be developed through the new standards development process, approved by the industry, and adopted by the board.

The Future — NERC’s strength lies in its ability to enlist the expertise of qualified individuals working in the electric supply systems of the United States and Canada. NERC will continue to help the electric industry work together “to keep the lights on.” Reliable interconnected electric systems are a prerequisite for a competitive electricity industry, and NERC has “taken the lead” and is working actively to ensure its “rules” for reliable electric system operation, such as these Operating Policies, are established and applied in a fair and nondiscriminatory manner.



NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

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Organization and Procedures Manual for NERC Standing Committees

**Approved by the Board of Trustees on
June 15, 2004**

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Introduction

NERC Mission

The North American Electric Reliability Council's (NERC's) mission is to ensure that the bulk electric system in North America is reliable, adequate, and secure. NERC accomplishes this mission by:

- Setting and enforcing standards for the reliable planning and operation of the bulk electric system.
- Certifying reliability service organizations and personnel.
- Assessing the historical and near-term reliability, and future adequacy of the bulk electric system.
- Providing reliability training and education resources.
- Facilitating information exchange, system modeling, and analytical methods and tools as needed for reliability.
- Interfacing with organizations in industry and agencies of the federal, state, and provincial governments in North America on reliability matters.
- Working with industry and government to coordinate the physical and cyber security of electricity infrastructure.

Corporate Overview

NERC is a not-for-profit corporation whose owners and members are the ten Regional Reliability Councils (Regional Councils). NERC is governed by an independent Board of Trustees elected by the Stakeholders Committee.

The members of the Regional Councils are from all segments of the electric industry — including investor-owned, federal, rural electric cooperatives, state, municipal, and provincial systems, exempt wholesale generators (independent power producers), and power marketers. These entities account for virtually all of the electricity supplied in the United States, Canada, and the northern portion of Baja California Norte, Mexico.

NERC Organizational Framework

The standing committees are one part of the overall NERC organization. An overview is provided below to illustrate how the standing committees fit into the organization and to identify key relationships with other NERC functions. The remaining sections of this manual describe the standing committees in greater detail, addressing committee scopes, organization, and procedures. Additional information regarding the other NERC functions listed below may be found in separate references on the NERC web site at www.nerc.com.

- **Board of Trustees** — provides leadership and sets policy for all NERC activities. The Board is comprised of ten independent Trustees, one of whom is the NERC president.
- **Stakeholders Committee** — is a senior executive group, representing a balance of stakeholder views, whose role is to advise the Board on policy issues. The Stakeholders Committee also

serves several corporate governance responsibilities assigned in the NERC Certificate of Incorporation and Bylaws.

- **Standards Authorization Committee** — manages the development of reliability standards and is elected by and accountable to a registered ballot body of industry stakeholders. The Board provides oversight to ensure the standards process remains open, inclusive, fair and balanced.
- **Compliance and Certification Committee** — manages the assessment, monitoring, and enforcement of compliance with reliability standards. This committee also manages the certification of reliability service organizations and personnel.
- **Critical Infrastructure Protection Committee** — advises the Board on matters related to the physical and cyber security of the electricity infrastructure of North America. The Critical Infrastructure Protection Committee develops security guidelines, interfaces with industry and various government agencies on security matters, and advises the operation by NERC of the Electricity Sector – Information Sharing and Analysis Center.
- **Standing Committees** — are comprised of volunteer industry experts in issues impacting reliability. The standing committees support NERC’s mission by carrying out the responsibilities stated in their scopes, by executing the policies, directives, and assignments of the Board of Trustees, and by advising the Board on reliability matters. The standing committees also advise the other NERC functions on matters requiring reliability expertise.

Manual Purpose and Applicability

This manual defines the scope, functions, representation, and procedures of the three NERC standing committees: Operating Committee, Planning Committee, and Market Committee. The manual is a living document that may be updated from time to time by approval of the NERC Board of Trustees. Changes to the manual may be recommended to the NERC Board for approval by any standing committee, with consultation of the other standing committees. The manual also applies to the subordinate groups of the three NERC standing committees.

All other NERC committees and their subordinate groups should use this manual as a procedural guide, and apply those sections of this manual that are applicable to their functions and organizational structure.

Committee Organization

Preface

One of NERC's most valuable assets is the reliability expertise provided by active participation of industry volunteers in NERC's committees and subordinate groups.

Establishment of Committees

The NERC Board of Trustees may create committees. In doing so, the Board approves the scope of each committee and assigns specific authorities to each committee necessary to conduct business within that scope. Each committee shall work within its Board-approved scope and shall be accountable to the Board of Trustees for its Board-assigned responsibilities.

Committee Scopes

NERC has three standing committees: Operating Committee, Planning Committee and Market Committee. The standing committees support the NERC reliability mission by executing the policies, directives, and assignments of the Board of Trustees, and advising the Board on reliability matters. The following functions are representative of the functions of the standing committees. A Board-approved scope outlining the responsibilities of each committee shall be available on the NERC web site. The Board may assign additional functions, as it deems appropriate. The following functions are representative of the functions of the standing committees:

- Assess resource and transmission adequacy and reliability performance.
- Provide reliability education and training resources.
- Coordinate reliability matters with Regional Councils and other organizations.
- Assess the reliability impacts of standards proposed or set by other organizations.
- Provide advice and recommendations on reliability applications, data, and services.
- Facilitate information exchange in support of reliable real-time operations.
- Assist in the development and the evaluation of the effectiveness of reliability standards.
- Provide advice and recommendations on the processes for assuring compliance and certification of reliability service organizations and personnel.
- Assess the impacts of standards and NERC activities on electricity markets and promote market solutions for reliability.
- Advise the NERC dispute resolution function.

Committee Scope Revisions

If the members of an existing committee determine that the committee's scope of work should be revised, the committee shall submit recommendations accordingly to the Board of Trustees for approval.

Committee Representation

General

Each committee shall have a defined membership composition that is approved by the Board. Membership composition may be unique to each committee. Although NERC committees historically have had fixed memberships, open membership may be appropriate in some cases, with Board approval. Membership composition of committees may evolve to meet changing needs of NERC and reliability stakeholders.

Each committee may propose for Board approval revisions to its membership composition. Each committee shall strive to maintain a membership composition that accomplishes two objectives:

- Balance representation among all stakeholders impacted by the work of the committee, consistent with NERC principles of being open, inclusive, and fair. Balance should include such factors as industry segment, region, Interconnection, and country. No one segment should be able to block or veto committee action, and no two segments should be able to form a sufficient majority to carry a committee motion.
- Provide expertise sufficiently robust to achieve technical excellence in fulfilling the scope and responsibilities of the committee.

The Board of Trustees may modify the committee membership composition or appoint additional voting or non-voting members to a committee, as it deems necessary to achieve these objectives.

Standing Committee Memberships

The membership composition of the Operating, Planning, and Market Committees is currently defined as follows:

- Voting Members (35)
 - Chairman (1) and Vice Chairman (1)
 - Regional Reliability Council (RRC) Representatives (13)
 - Eastern Interconnection (9) (Including 1 from Eastern Canada)
 - Western Interconnection/WECC (3) (Including 1 from Western Canada)
 - Texas Interconnection/ERCOT (1)
 - Other At Large Canada Representatives (2)
 - Stakeholder Segment Representatives (18)
 - Independent System Operator/Regional Transmission Operator (2)
 - Investor-Owned Utility (2)
 - Federal (U. S.) (2)
 - Transmission Dependent Utility (2)
 - State/Municipal Utility (2)
 - Cooperative (2)
 - Merchant Electricity Generator (2)
 - Electricity Marketer (2)
 - End-use Electricity Customer (2)

Committee Representation

- Non-Voting Members
 - Regulator (State and Provincial) Representatives (4)
 - Western (1)
 - Eastern (1)
 - Texas (1)
 - Canada (1)
 - Regulator (Federal) Representatives (2)
 - U. S. Federal Energy Regulatory Commission (1)
 - Canada National Energy Board (1)
 - Observer Representatives (Same as Board Observers)
 - Committee Secretary (NERC Staff Coordinator)
 - Prior Chairman (*ex officio* non-voting member, at the discretion of the chairman)

Committee Member Terms

Unless otherwise stated in the specific requirements of a committee, committee members, including non-voting members, shall have a term of two years. To assure continuity, terms should be staggered to allow about half of the members' terms to expire each year. The terms of committee officers need not be staggered.

Prior Chairman

At the discretion of the current chairman, the immediately prior chairman may serve *ex officio* as a non-voting member of the committee.

Committee Membership

Principles

Committee members shall be nominated and selected in a manner that is open, inclusive, and fair. All committee member appointments shall be approved by the Board of Trustees and committee officers shall be appointed by the Board chairman.

Procedure for Appointing Committee Members

Each committee with a fixed membership composition shall maintain a Nominating Task Force, whose responsibilities are described below and later in this manual.

Each committee with a fixed membership shall conduct an open nominations process to receive nominations to fill any membership vacancies. Generally this process will be conducted annually to replace members whose terms are expiring.

NERC staff shall, under the oversight of the Technical Steering Committee or a committee chairman, administer the nominations process. The nominations process should be conducted jointly across committees when vacancies are being filled across multiple committees. The Technical Steering Committee, whose responsibilities are defined later in this manual, shall oversee the conduct of the nominations process when more than one committee is involved. The committee chairman shall oversee the conduct of the nominations process when only one committee is involved.

A request for nominations should specify the committee positions to be filled, the qualifications for filling each position, and additional considerations in evaluating candidates, such as areas of expertise needed on the committee.

Generally a request for nominations should provide a window of at least 30 days for submission of nominations. Shorter nominating periods may be necessary on an exception basis if there is an urgent need in the view of the Technical Steering Committee or committee chairman, as applicable.

NERC staff shall forward nominations received to the Nominating Task Force of each respective committee. The Nominating Task Force shall fairly evaluate the nominees using criteria established in the solicitation and the best judgment of the task force on how best to fulfill the membership needs of the committee. The Nominating Task Force shall then prepare its recommended slate of members and indicate the terms of each member and candidate.

The Nominating Task Force shall present the recommended committee membership slate to the Board for approval. The Nominating Task Force may present the proposed slate to the committee for information purposes before submitting the slate to the Board, but the committee does not act on the slate.

The Board of Trustees, by virtue of approving a committee slate, appoints each voting and non-voting committee member. The Board may also appoint members individually as needed for replacement.

Procedure for Appointing Committee Officers

The process for appointing committee officers is similar to that previously described for committee members, except for the approval steps. With due consideration of the open nominations process

Committee Membership

described above, the Nominating Task Force shall prepare a slate of officer candidates and present the proposed slate for the committee to consider. The committee shall consider the recommended slate of the Nominating Task Force and any additional nominations the members may offer from the floor, and approve a recommended slate of officers. The committee shall present the slate of committee officers to the chairman of the NERC Board of Trustees, who shall appoint committee officers with due consideration of the committee's recommended slate.

General Criteria for Membership

The Nominating Task Force shall consider the following general criteria, in addition to specific committee membership requirements, in preparing a recommended slate:

- Each Regional Council shall appoint committee members that are designated as representing their region. Regional Council representatives should be capable of representing the region in committee activities.
- The Canadian Electricity Association shall appoint Canadian representatives. Canadian representatives should be capable of representing Canada in committee activities.
- Industry stakeholder segments may elect their segment representatives through an open process approved by the NERC Board of Trustees, with a balance of Interconnection and geographic considerations as appropriate. Otherwise, the Nominating Task Force may give preference to candidates nominated by organizations representing a broad cross section of an industry segment, such as an industry trade association.
- No individual may serve concurrently on more than one standing committee.
- No two individuals from the same organization, or affiliated organizations, may serve concurrently on one standing committee.
- No more than two individuals from the same organization should serve concurrently on the several standing committees.

Replacement of Resigning or Non-participating Members

In the event a voting or nonvoting member can no longer serve on the committee, that member shall submit a written resignation to the committee chairman or secretary.

The chairman should request any committee member who ceases to participate in the committee, as indicated by not attending or sending a proxy for two consecutive meetings, to submit a resignation or to request continuation of membership with an explanation of extenuating circumstances. If a written response is not received within 30 days of the chairman's request, the lack of response should be considered a resignation.

The committee chairman shall refer the vacancy resulting from a resignation to the Nominating Task Force. The nomination and selection of replacement members shall be conducted in an open, inclusive and fair manner, using a process similar to that used for the annual membership solicitation. The Task Force shall request NERC staff to prepare a solicitation for nominations to fill that position. The Nominating Task Force shall follow the previously stated criteria in recommending a replacement.

The committee chairman may seek a vote of the committee to allow the proposed replacement member to be seated pending appointment of the replacement at the Board's next scheduled meeting.

Changes in Member Affiliation

A committee member who moves from one organization to another shall have the option of retaining the membership position if the new organization is in the same constituency (industry segment, region, etc.) and no membership conflicts are created per the General Criteria for Membership. If the new affiliation changes the member's constituency, then the member shall resign from the committee.

If the change in affiliation results in two members from the same organization on a committee, or other conflict with membership criteria stated in this manual, those two members should identify who will stay on the committee and who will resign. The committee chairman shall act to address the conflict by removing one of the members from membership, if the members do not resolve the conflict within 30 days.

Acknowledgement of a Membership Conflict

Any committee member who knows of any form of membership conflict, such as working for an entity affiliated with that of another committee member, shall notify the committee chairman within ten (10) business days of obtaining that knowledge.

Committee General Procedures

Committee General Procedures

Conduct of Meetings

In the absence of specific provisions in this manual, all committee meetings shall be conducted in accordance with the most recent edition of Robert's Rules of Order in all cases to which they are applicable.

Presiding Officer

The committee chairman shall preside at a committee meeting or designate the vice chairman or another committee member to preside. The presiding officer of a meeting is designated below as the "chair" rather than the chairman, since the presiding officer may or may not be the committee chairman.

Calling of Meetings

Generally, the standing committees shall conduct three meetings per year, coordinated to be in the same location and to be concurrent or sequential as needed to address common business. Each committee chairman may call for additional meetings as needed to accomplish the assigned responsibilities of the respective committee.

Meeting Locations

To facilitate travel associated with meetings, all committees and subordinate groups shall exercise good judgment in selecting meeting locations by considering cost, travel time, and convenience for all participating members and observers.

Open Meetings

NERC committee meetings shall be open to the public, except as noted below under Confidential Sessions. Although meetings are open, action on items before a committee shall be determined only by the voting members of the respective committee.

All persons not otherwise affiliated as voting or non-voting members of the committee shall be designated as committee guests. Committee guests shall not be permitted to vote and shall have no bearing on the existence of a quorum. It shall be the chair's prerogative to determine whether and when it is appropriate to include the comments and questions of the committee guests in the proceedings of the committee.

Confidential Sessions

The chair of a committee may limit attendance at a meeting or portion of a meeting, based on confidentiality of the information to be disclosed at the meeting. Such limitations should be applied sparingly and on a non-discriminatory basis as needed to protect information that is sensitive to one or more parties. A preference, where possible, is to avoid the disclosure of sensitive or confidential information so that meetings may remain open at all times. Confidentiality agreements may also be applied as necessary to protect sensitive information.

Committee General Procedures

Meeting Registration

All committee members, observers, and guests must register in advance for any meeting of the committee for which registrations are required. Advance registration allows preparation of adequate accommodations suitable for conduct of committee business.

Antitrust

All persons attending or otherwise participating in a NERC committee meeting shall act in accordance with NERC's Antitrust Compliance Guidelines at all times during the meeting. A copy of the NERC antitrust statement shall be included with each meeting agenda.

Quorum

The quorum necessary to transact business at meetings of a committee shall be two-thirds of the voting members of the committee, excluding any vacant positions. Voting members approved by the committee on an interim basis pending confirmation by the Board shall be counted in the determination of a quorum.

If a quorum is not present, then the committee may not take any actions requiring a vote of the committee. However, the chair may, with the consent of the members present, elect to allow discussion of agenda items.

Voting Procedure

Committee action requires a two-thirds majority of the votes cast at a meeting in which a quorum is present. For the purpose of determining a two-thirds majority, abstentions do not count. Therefore the vote to approve a motion is calculated as the affirmative votes divided by the sum of the affirmative votes and the negative votes.

Each voting member of the committee shall have one vote and may not serve as the proxy of another member.

The chairman and vice chairman of each committee shall be voting members of their respective committees and may choose, at their discretion, to vote on any action of the committee.

Non-voting members, observers, and guests shall not be allowed to vote, unless serving as a proxy for a voting member.

Majority and Minority Views

Consistent with this manual and Robert's Rules of Order, all members of a committee should be afforded the opportunity to provide alternative views on an issue. The results of committee actions, including recorded minutes, shall reflect the majority as well as any minority views of the committee members. The chairman shall communicate both the majority and any minority views in presenting results to the Board of Trustees.

Committee General Procedures

Proxies

A substitute representative, or proxy, may attend and vote during all or a portion of a committee meeting in lieu of a voting member, provided the absent member notifies the committee chairman, vice chairman, or secretary of the proxy. Such notification shall be in writing (electronic medium is acceptable). The proxy representative and his or her affiliation shall be named in the correspondence.

A voting member of a committee may not serve as a proxy for another voting member on the same committee (a member may not carry more than one vote).

Notice of Committee Agenda

The publication of an agenda of actions to be voted upon by the committee shall include the precise wording of any proposed motion. The sponsor of the motion shall prepare a brief description of the justifications for the motion and other information that would be useful to committee members in considering the motion.

In general, action may not be brought to a vote of the committee unless it has been noticed in a published agenda or other form of distribution to the committee at least ten (10) business days before the meeting date upon which action is to be voted. This requirement for a 10-day notice may be waived either by the approval of the chair or by a two-thirds affirmative vote of the committee's voting members present at a committee meeting at which a quorum has been established.

Action without a Meeting

Any action required or permitted at a meeting of the committee may be taken without a meeting if a two-thirds majority of the committee members entitled to vote on the action approves taking the action outside of a meeting.

Such action without a meeting shall be performed by mail or electronic ballot (e.g., telephone, facsimile, e-mail, or Internet). Written notice to the committee members of the subject matter for action is required not less than ten (10) business days, nor more than sixty (60) calendar days prior to the date on which the action is to be voted. As time permits, members should be allowed a window of ten (10) business days to vote. Committee members shall receive written notice of the results of such an action within ten (10) business days of the close of the voting period. All responses of the committee members shall be filed as a roll call vote with the committee minutes.

Such action without a meeting shall not preclude the Executive Committee of a committee from exercising the powers of the committee between meetings of the committee as described later in the section on Executive Committees.

Meetings by Telephone and Electronic Media

Working groups, task forces, and other small groups are encouraged to use telephone conference calls and electronic media such as the Internet and email to conduct their business. These alternatives are particularly suitable when the group size is manageable for the selected medium and when the agenda is simple and only a few actions are anticipated.

Committee General Procedures

Face-to-face meetings are encouraged, however, for larger groups and complex agendas with multiple action items. Meeting in person ensures sufficient opportunity to debate alternative views and resolve issues. In general, standing committee meetings should be conducted in person. Subcommittee meetings should also be conducted in person, unless the agenda is manageable for an alternative medium.

For face-to-face meetings, all members are responsible for attending in person or providing a proxy. Participating by telephone in a face-to-face meeting of a committee or subcommittee is discouraged and shall be allowed only at the discretion of the chairman of the committee or subcommittee. Telephonic participation in working group or task force meetings may be practical, but shall be at the discretion of the group chairman.

Dispute Resolution

Each committee shall strive to resolve any and all disputes that may arise in the conduct of committee business by using the procedures in this manual and in Robert's Rules of Order to resolve such disputes. Any committee member or group of members involved in a dispute shall notify the chairman in writing regarding the specific details of the dispute, including any procedural errors or unfair actions believed to have occurred and any adverse consequences. Each committee member or group of members involved in the dispute shall apply a best effort to resolve the dispute under the guidance of the committee chairman. The dispute may be resolved using whatever methods the chairman may deem appropriate, consistent with this manual and Robert's Rules of Order. If, after notifying the committee chairman of the dispute, a committee member or group of members deems that the dispute cannot be resolved by working further with the chairman, the member or group of members shall have the right to submit a grievance to the NERC General Counsel, requesting action under an applicable NERC dispute resolution program.

Responsibilities of Officers, Executives, and Members

Responsibilities of Officers, Executives, and Members

Committee Chairman and Vice Chairman Responsibilities

The chairman of the NERC Board of Trustees appoints the chairman and vice chairman of each standing committee, with due consideration of each committee's recommended slate of officers. A committee's chairman and vice chairman are appointed to serve two-year terms and may be reappointed for succeeding terms at the discretion of the Board chairman.

The chairman and vice chairman of a standing committee are responsible to the NERC Board of Trustees. They serve at the pleasure of the Board chairman and may be replaced by the Board chairman at any time. Appointment by the Board chairman is intended to ensure the committee chairman and vice chairman are responsive to the Board, including representing both majority and minority views to the Board.

If the members of a committee, or a portion thereof, wish to challenge the continued tenure of either or both committee officers, those members may present just cause for termination to the Board for consideration.

The vice chairman shall assume the responsibilities of the chairman in the absence of the chairman or if the chairman position is vacated for any reason. A committee vice chairman may succeed to a committee chairman, if so appointed by the Board chairman.

Each committee chairman and vice chairman shall be a voting member of their respective committee. However, while acting in any aspect of committee business, they shall strive to not represent specific regions or segments, or any other electric industry entities. The officers shall, as appointees of the Board chairman, fairly represent the views of the committee, including both majority and minority views.

In addition to the duties, rights, and privileges discussed above and elsewhere in this manual, the chairman shall have the following responsibilities:

- Provide general supervision of committee activities.
- Coordinate the schedule of all committee meetings including approval of meeting duration and location.
- Develop committee agendas, and rule on any deviation, addition, or deletion from a published agenda.
- Preside at committee meetings or appoint a presiding officer when not available.
- As presiding officer, manage the conduct of committee meetings, including the nature and length of discussion, recognition of speakers, motions, and voting.
- As presiding officer, recognize proxies at committee meetings.
- Act as spokesperson for the committee at forums within and outside NERC.
- Serve as a member of the Technical Steering Committee of NERC.
- Attend meetings of the NERC Board of Trustees and report to the Board on committee activities.
- Report on both minority and majority opinions on items brought by the committee to the Board for information or action.

Responsibilities of Officers, Executives, and Members

- Perform other duties as directed by the NERC Board of Trustees.

The vice chairman shall assume the responsibilities of the chairman under the following conditions: a) at the discretion of the chairman (for brief periods of time); b) when the chairman is absent or temporarily unable to perform the chairman's duties; or c) when the chairman is permanently unavailable or unable to perform the chairman's duties. In the case of a permanent change, the vice chairman shall continue to serve until a new chairman is appointed by the chairman of the NERC Board of Trustees.

In addition to the duties, rights, and privileges described above and elsewhere in this manual, the vice chairman shall have the following responsibilities:

- Assist the committee chairman as called upon.
- Serve as a member of the Technical Steering Committee of NERC.
- Attend meetings of the Board of Trustees.

Secretary Responsibilities

At the first regularly scheduled committee meeting following the appointment of a new committee chairman or the reappointment of a committee chairman, the committee shall elect a member of the NERC staff to serve as secretary of the committee. The committee secretary shall not have the power to vote and shall not be counted in determining the existence of a committee quorum.

In addition to the duties, rights, and privileges described elsewhere in this manual, the secretary shall have the following responsibilities:

- Serve under the direction of the committee officers, the committee's Executive Committee, and be guided by the decisions of the committee.
- Be responsible for the day-to-day operation and business of the committee.
- Prepare and distribute the notices of the committee meetings, prepare the meeting agenda.
- Within three weeks of each meeting, prepare and distribute the draft minutes of the meeting.
- Maintain a general record of all of the proceedings of the committee.
- Serve as the *ex officio*, nonvoting secretary of the committee's Executive Committee.
- Act as the committee's parliamentarian.

Executive Committee Responsibilities

Each committee shall have an Executive Committee that is comprised of the committee chairman and vice chairman, and a designated number of at-large voting members of the committee. This designated number shall be three (3), unless the committee approves an alternative number. The number of additional committee members on the Executive Committee should be large enough to fairly represent the diverse views of the committee yet small enough to be practical for urgent actions between committee meetings, and shall be a minimum of three (3) additional members. The Secretary shall serve as a non-voting member of the Executive Committee.

Responsibilities of Officers, Executives, and Members

The committee's Nominating Task Force shall present a slate of candidates to serve as Executive Committee at-large members. The committee shall elect the at-large members of the Executive Committee at the first regularly scheduled committee meeting following the appointment of a new committee chairman or the reappointment of the committee chairman.

The Executive Committee of a committee may exercise all the powers of the full committee between meetings of the committee. It is preferred, however, to the extent practical, that the committee assigns an action to the Executive Committee in advance, or that an action is deferred to the committee as a whole. When acting between meetings, Executive Committee members should consult standing committee members as needed to obtain guidance for decisions being considered.

The Executive Committee shall notify the committee as soon as possible after the Executive Committee takes any action. The Executive Committee shall at the next full committee meeting submit any actions it has taken for ratification of the committee. If a committee does not ratify an action of the Executive Committee, that action shall nonetheless remain in effect unless and until it is modified or annulled by action of the committee.

The Executive Committee shall assist the committee chairman, as requested, in the following activities:

- Review committee meeting agendas prepared by the secretary.
- Coordinate committee and subgroup activities.
- Respond to urgent matters of the committee.
- Prepare reports to the NERC Board of Trustees.

The committee chairman may call for a meeting of the Executive Committee at any time. The chairman may also invite others to meetings of the Executive Committee as needed. An Executive Committee member who is unable to attend a meeting is encouraged to designate a proxy by providing written notice (electronic medium is acceptable) to the chairman, vice chairman, or secretary. A voting member of the Executive Committee may not serve as a proxy for another voting member (a member may not carry more than one vote).

Nominating Task Force Responsibilities

Each standing committee shall have a Nominating Task Force, whose five members shall be nominated by the committee chairman and approved by the committee, respectively. The committee chairman shall appoint the task force chairman from among the five task force members.

In addition to the duties, rights, and privileges described elsewhere in this manual, the Nominating Task Force shall have the following responsibilities:

- Prepare every two years, or as requested, a proposed slate of committee officers for the committee to consider. The committee's recommended slate of officers shall be provided to the chairman of the NERC Board of Trustees for consideration in appointing the committee chairman and vice chairman.
- Prepare a slate of three (or an alternative number specified for the committee) voting members of the committee to serve as Executive Committee members, in conjunction with the committee chairman and vice chairman. This slate shall be presented to the committee for election at the first regularly scheduled committee meeting following the appointment of a new committee chairman or the reappointment of the committee chairman. In selecting members of the Executive Committee, the Nominating Task Force should consider rotating the membership of

Responsibilities of Officers, Executives, and Members

the Executive Committee on the basis of industry segment, Regional Council, Interconnection, country, industry segment, and other factors considered in balancing committee membership.

- Prepare annually, or as requested, a slate of voting and non-voting committee members to fill designated committee vacancies.

Responsibilities of Officers, Executives, and Members

Committee Member Responsibilities

Each committee member should strive in all committee activities to represent the interests of the position that member fills, to the best of his or her judgment.

Non-voting members shall be full members of their respective committees in every respect, except that they shall not participate in voting, and they shall not be counted in determining a quorum.

In addition to the duties, rights, and privileges described elsewhere in this manual, each committee member shall have the following responsibilities:

- During the conduct of all committee business, act consistently at all times with the procedures in this manual and Robert's Rules of Order.
- Provide knowledge and expertise in support of committee activities.
- Seek advice and opinions from constituents represented by the committee position served by the member.
- Respond in a timely manner to all committee requests, including requests for reviews, comments, and votes on issues before the committee.
- Arrange for a proxy to attend and vote at committee meetings in the member's absence.
- Respond in a timely manner to all requests to register for committee meetings.

Subordinate Groups

Committee Organization Hierarchy

The standing committee organizational structure shall be arranged to support a superior-subordinate hierarchy that is ordered as follows:

- Committee
- Subcommittee
- Working Group
- Task Force

The committee is the superior classification within the hierarchy, other than the NERC Board of Trustees (to which each committee reports).

Each committee may establish subcommittees, working groups, and task forces when there is a clear purpose and scope to be fulfilled. The committee chairman may also form any of these subordinate groups on behalf of the committee. Formation of a committee or group requires confirmation of the chairman of the next superior committee or group in the hierarchy. For example, committee formation of a subcommittee shall be confirmed by the NERC chairman, subcommittee formation of a working group shall be confirmed by the committee chairman, and so forth.

The committee shall be the responsible sponsor of all subordinate subcommittees, working groups, or task forces it may create, or that its subordinate subcommittees and working groups may create. The committee shall keep the Board of Trustees informed of all groups subordinate to the committee.

Subcommittees

A standing committee may establish subcommittees to which certain of the committee's broadly defined continuing functions may be delegated. The committee shall approve the scope of each subcommittee it forms. The committee chairman shall appoint the subcommittee officers (typically a chairman and vice chairman) for a specific term (generally two years). The subcommittee officers may be reappointed for additional terms. The subcommittee shall be accountable for the responsibilities assigned to it by the committee and shall at all times work within its assigned scope.

Working Groups

A committee or any of its subcommittees may delegate specific continuing functions to a working group. The sponsoring committee or subcommittee shall approve the scope of each working group it forms. The chairman of the sponsoring committee or subcommittee shall appoint the working group officers (typically a chairman and vice chairman) for a specific term (generally two years). The working group officers may be reappointed for additional terms. The sponsoring committee or subcommittee shall conduct a "sunset" review of each working group every two years. The working group shall be accountable for the responsibilities assigned to it by the committee or subcommittee and shall at all times work within its assigned scope.

Task Forces

A committee, subcommittee, or working group may assign specific work of a finite duration to a task force. The sponsoring committee, subcommittee, or working group shall approve the scope of each task force it forms. The chairman of the sponsoring committee, subcommittee, or working group shall appoint the task force officers (typically a chairman and vice chairman, but a vice chairman may not be required in all cases). Each task force shall have a finite duration, normally less than one year. The sponsoring group shall review the task force scope at the end of the expected duration and at each subsequent meeting of the sponsoring group after that until the task force is retired. Action of the task force sponsoring group is required to continue the task force past its defined duration. The sponsoring group should consider promoting to a working group any task force that is required to work longer than one year.

Subgroup Membership and Representation

The membership of each subcommittee, working group and task force should be established to address the needs for expertise and balancing of interests. Each group's membership requirements shall be defined within the group's approved scope.

As a general guide, the broader the group's scope, the more emphasis there should be on balancing of interests. Therefore subcommittees would be expected to have a broader representation of industry segments, while a task force may be more focused on simply having the necessary expertise and a working group may be somewhere between.

Each member of a subordinate group, and its officers, shall be appointed by the chairman of the sponsoring committee or group. It is desirable for subgroup officers to be members of the sponsoring committee or group.

To the extent subgroup membership is of a representative nature, recommendations for staffing of the group should be provided in a manner consistent with the principles outlined in the staffing of a committee, including the use of an open nominations process. Regional Council representatives should be recommended by the Region and Canadian representatives by the Canadian Electricity Association. Preference may also be given to representatives recommended by broadly-based industry associations.

To the extent subgroup membership is based on providing requisite expertise, the chairman of the sponsoring committee or group may appoint members based on the relevant technical qualifications.

Subgroup Procedures

Subcommittees, working groups, and task forces shall conduct business in a manner consistent with all applicable sections of this manual and Robert's Rules of Order.

Inter-Committee Coordination

Technical Steering Committee

The Technical Steering Committee is a committee comprised of the chairman and vice chairman of each committee (Planning Committee, Operating Committee, Market Committee, Critical Infrastructure Protection Committee, Standards Authorization Committee, and the Compliance and Certification Committee), the chairman of the Regional Managers, and the president and senior vice president of NERC. The NERC president may on occasion invite additional persons to participate in Technical Steering Committee activities.

The purpose of the Technical Steering Committee is to facilitate the exchange of information and to coordinate activities among the committees. The Technical Steering Committee has the following functions:

- Communicate issues among committees.
- Coordinate work plans and priorities among committees.
- Coordinate meeting agendas among committees.
- Coordinate subgroup assignments and efficient allocation resources among committees.
- Coordinate the joint approval of results when more than one committee is involved.
- Prepare joint reports to the Board when more than one committee is involved.
- Identify differences among committees on particular issues and report them to the NERC president. As requested, assist the NERC president in resolving such differences.

The NERC president shall serve as chairman of the Technical Steering Committee.

Executive Committees in Joint Session

The Executive Committees of the committees may have occasion to meet in joint session, at the discretion of the NERC president or the Technical Steering Committee. The Executive Committees may periodically be assigned work by the NERC president or the Technical Steering Committee, such as evaluating proposed revisions to existing NERC planning standards and operating policies, or resolving issues common among the committees.

When the Executive Committees meet in joint session, they shall elect a chair to preside over the meeting.

When in joint session, each Executive Committee shall be allocated one vote per member or proxy present at the meeting, up to a maximum of five (5) votes per Executive Committee. In the event an Executive Committee has more than five (5) members present, the chairman of that committee shall at the beginning of the meeting designate the voting members for that meeting.

The NERC president may appoint adjunct members when the Executive Committees meet in joint session. In this case, each adjunct member carries one vote, up to a maximum of five (5). For example, the NERC president may appoint the chairman of the regional managers or officers of other NERC groups to serve with the Executive Committees in joint session, but in no case shall more than five (5) adjunct voting members be appointed.

Work Plan and Resource Coordination

Each committee shall maintain a work plan prioritizing existing and future work of the committee. The plan shall address broad committee functions as well as specific tasks assigned to the committee. The plan shall indicate target schedules for completion of milestones, and how work has been assigned to various resources of the committee.

Periodically, but no less than once per year, the Technical Steering Committee shall coordinate the work plans and resource assignments across the committees. The purpose of this review shall be to:

- Ensure functions and work assignments are properly allocated across the committees, consistent with each committee's scope.
- Ensure work is being allocated efficiently to subgroups across the committees, with no undue redundancies.
- Ensure the committees effectively integrate results on jointly shared issues.

Each chairman shall keep the committee informed of the work plan and the results of coordination with the other committees.

Committees in Joint Session

Two or more committees may, at the discretion of their chairmen, meet in a joint session. A joint session among committees may be appropriate when two or more committees need to take action on an issue and joint discussion of that action will be beneficial to the decision. During a joint session, the chairmen involved will agree which among them will chair the joint session. The committee general procedures in this manual and Robert's Rules of Order apply in a joint session of two or more committees.

When no actions are to be taken jointly by multiple committees, committees may still meet jointly, out of session, to hear informational presentations or discussions.

Resolving Differences among Committees

The Board of Trustees has assigned to the NERC president the responsibility for resolving differences among committees and for presenting to the Board both minority and majority views on these differences. In fulfilling this responsibility, the NERC president may enlist the Technical Steering Committee or others to help articulate and resolve differences.

Consistent with its scope, each committee reserves the right to review, comment, and make recommendations to the Board regarding the work of other committees.

Appendix A – Revisions to Manual

Appendix A – Revisions to Manual

The following list summarizes the revisions to this manual from May 1999 forward.

May 10, 1999 – The Interim Organization and Procedures Manual for the NERC Standing Committees was approved by the NERC Board of Trustees at its May 10, 1999 meeting. The original draft had been prepared by the Standing Committees Task Group of the NERC Board of Trustees.

February 7, 2000 – An Organization and Procedures Manual for the NERC Standing Committees was approved by the NERC Board of Trustees at its February 7, 2000 meeting. This February 2000 version was based on comments received on the May 1999 interim manual. The revisions included: a procedure for modifying the manual, the addition and formalization of a past committee chairman position and committee secretary position, the addition of guidelines (previously approved by the NERC Board in January 1999 and May 1999) to be considered in the selection or election of committee members, the change in the name of the Security Committee back to the Operating Committee, and some minor modifications and editorial changes for increased clarity and consistency.

October 12, 2000 – A revised Organization and Procedures Manual for the NERC Standing Committees was approved by the NERC Board of Trustees at its October 12, 2000 meeting. This version included the three NERC committees' recommendation to change the term of office of the officers and members of the NERC standing committees from one to two years, beginning July 1, 2001; the NERC Adequacy Committee's recommendation to change its name to the Planning Committee, effective immediately; and the associated conforming changes to the manual.

June 10, 2003 – The manual was revised to incorporate committee changes resulting from the new NERC reliability standards process, to add a section on inter-committee coordination, to clarify procedural requirements, and otherwise improve the structure and clarity of the manual.

June 15, 2004 – The manual was revised to accommodate the NERC board's June 10, 2003 approval of the new Compliance and Certification Committee, the board's February 10, 2004 decisions to: 1) change the Critical Infrastructure Protection Advisory Group to the Critical Infrastructure Protection Committee, and 2) add the chairmen and vice chairmen of the Critical Infrastructure Protection Committee, the Standards Authorization Committee, and the Compliance and Certification Committee to the Technical Steering Committee. The associated conforming changes were also made to the manual.

NERC Reliability Coordinator Standards of Conduct

Introduction

An entity performing the functions of RELIABILITY COORDINATOR must treat all users of the interconnected transmission systems in a fair and non-discriminatory manner. A RELIABILITY COORDINATOR must conduct its affairs in conformance with the following standards:

1. General rule.

- 1.1. Independence.** Except as provided in paragraph 1.2 of this section, the RELIABILITY COORDINATOR, its employees, or the employees of any of its affiliates who perform RELIABILITY COORDINATOR functions (“RELIABILITY COORDINATOR employees”) must operate independently of employees/persons who engage in retail (energy purchases for or sales to native load customers) or wholesale (energy purchases or sales for resale) merchant functions (“Merchant employees”). [Note: “Operate independently” does not mean or require corporate separation of the RELIABILITY COORDINATOR from the Transmission Provider or Merchant employees or merchant functions.]
- 1.2. Emergency actions.** Notwithstanding any other provision of these standards of conduct, in emergency circumstances that could jeopardize operational security, RELIABILITY COORDINATORS may take whatever steps are necessary to maintain system security.
- 1.3. Reporting deviations from these Standards.** RELIABILITY COORDINATORS must report to NERC and the appropriate REGIONAL COUNCIL(S) the details of any deviation from these standards of conduct, within 24 hours of such deviation. NERC staff will post the reports to the NERC RELIABILITY COORDINATOR web site.

2. Rules governing employee conduct.

- 2.1. Prohibitions.** RELIABILITY COORDINATOR employees are prohibited from:
 - 2.1.1. Merchant functions.** Conducting Merchant functions except as outlined in 1.2 above.
 - 2.1.2. Access to control facilities.** Allowing access for Merchant employees to the system control center or similar facilities used for RELIABILITY COORDINATOR functions that differs in any way from the access available to non-affiliated TRANSMISSION CUSTOMERS.
 - 2.1.3. Disclosing system information.** Disclosing to Merchant employees any information concerning the transmission system through non-public communications conducted off the OASIS, through access to information not posted on the OASIS that is not at the same time available to non-affiliated Transmission Customers without restriction, or through information on the OASIS that is not at the same time publicly available to all OASIS users (such as E-mail). If a RELIABILITY COORDINATOR employee discloses information in a manner contrary to the requirements of this subparagraph, the RELIABILITY COORDINATOR must, as soon as practicable, post such information on the NERC RELIABILITY COORDINATOR web site and inform the affected Transmission Provider to post such information on its OASIS.
 - 2.1.4. Sharing market information.** Sharing market information acquired from non-affiliated TRANSMISSION CUSTOMERS or potential non-affiliated Transmission

NERC Reliability Coordinator Standards of Conduct

Customers, or developed in the course of performing RELIABILITY COORDINATOR functions, with any Merchant employees.

- 2.2. Transfers.** RELIABILITY COORDINATOR employees or Merchant employees are not precluded from transferring between such functions as long as such transfer is not used as a means to circumvent these standards of conduct. Notices of any employee transfer to or from RELIABILITY COORDINATOR functions must be reported to NERC and the appropriate REGIONAL COUNCIL(S). NERC staff will post the reports to the NERC RELIABILITY COORDINATOR web site. The information to be posted must include: the name of the transferring employee, the respective titles held while performing each function (i.e., on behalf of the RELIABILITY COORDINATOR, merchant or transmission provider, or merchant or transmission affiliate), and the effective date of the transfer. The information posted under this section must remain on the NERC web site for 90 days.
- 2.3. Books and records.**

 - 2.3.1. Available for audit.** A RELIABILITY COORDINATOR must keep sufficient records of its activities available for audit.
 - 2.3.2. Separate records.** A RELIABILITY COORDINATOR must maintain its records separately from those of any affiliates and these must be available for inspection by NERC and the appropriate Regional Council(s).
- 3. Rules governing maintenance of written procedures.**

 - 3.1. Publicly available.** A RELIABILITY COORDINATOR must provide an explanation for posting on the NERC RELIABILITY COORDINATOR web site describing the implementation of these standards of conduct in sufficient detail to demonstrate that the RELIABILITY COORDINATOR employees operate independently from merchant employees and that it is otherwise in compliance with these requirements.
 - 3.2. Provided to all employees.** A copy of the signed Standards of Conduct document shall be given to all employees with RELIABILITY COORDINATOR responsibilities.

AGREEMENT

As part of the process of being designated a NERC RELIABILITY COORDINATOR, [*Name of Organization*] hereby agrees to abide by the terms of the foregoing NERC Reliability Coordinator Standards of Conduct.

[*Name of Organization*]

By: _____

Title: _____

Date: _____

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

By: _____

Title: _____

Date: _____

Training Documents

Area Interchange Error Survey Training Document

Training Document Subsections

- A. Effects of Area Interchange Error on the Interconnection
 - B. Area Interchange Error
 - C. Survey Procedures
 - D. Survey Review
-

A. Effects of Area Interchange Error on the Interconnection

[Policy 1A – Control and Performance]

Each CONTROL AREA is required to continually balance its generation and interchange schedules to its load (Reference: Operating Policy 1A., “Control and Performance”). The CONTROL AREA’S Area Interchange Error (AIE) is zero as long as this balance is maintained. When a CONTROL AREA fails to maintain this balance, it causes the Interconnection frequency to increase (from overgeneration) or decrease (from undergeneration). The CONTROL AREA’S AIE is equal to the imbalance.

The effect is cumulative for all the CONTROL AREAS in the INTERCONNECTION. The magnitude of the “frequency error” — the difference between actual and scheduled frequency¹ — is directly proportional to the total magnitude of the load and generation imbalances of the control areas in the INTERCONNECTION.

Actual INTERCONNECTION frequency is usually slightly above or below scheduled frequency due to the reactionary nature of generation control systems. However, when the INTERCONNECTION’S frequency error from 60 Hz remains consistently positive or negative, it causes an increasing fast or slow time error, respectively. The time error is proportional to the total magnitude *and the duration* of the load and generation imbalances of the CONTROL AREAS in the INTERCONNECTION.

A prolonged frequency error or rapid accumulation of time error indicates a significant generation/load imbalance (i.e., a non-zero AIE) in one or more CONTROL AREAS within the INTERCONNECTION. An AIE survey is a means of determining these CONTROL AREAS. All CONTROL AREAS within an INTERCONNECTION participate in an AIE survey.

This document describes the survey procedure, includes specific instructions for completing the AIE survey form and calculating the AIE, and discusses survey results.

¹When a time correction is in effect, scheduled frequency is offset slightly from 60.00 Hz in the appropriate direction. Frequency error during a time correction will either impede or accelerate the time correction.

B. Area Interchange Error

1. **Area Control Error (ACE).** ACE is the *instantaneous* difference between the actual and scheduled interchange of a CONTROL AREA and includes a component for frequency bias. It may also include components for regulation service, electronic load or generation transfer, jointly owned generating units, and meter error. [Appendix 1A – The Area Control Error Equation]

The formula for calculating the CONTROL AREA'S ACE using tie line bias is:

for the Eastern and ERCOT INTERCONNECTIONS, and

$$ACE = (Ni_A - Ni_S) - 10\beta(f_A - f_S)$$

for the Western Interconnection

$$ACE = (Ni_A - Ni_S) - 10\beta(f_A - f_S) - s(0.3\beta_t t_d)$$

where,

Ni_A = Actual instantaneous net interchange (MW) X the algebraic sum of the power flows on the CONTROL AREA'S tie lines. Positive net interchange is a net power flow out of the CONTROL AREA.

Ni_S = Scheduled net interchange (MW) X the mutually prearranged intended net power flow on the CONTROL AREA'S tie lines. Positive net interchange is a net power flow out of the CONTROL AREA.

f_A = Actual frequency (Hz) X the actual frequency in the INTERCONNECTION.

f_S = Scheduled frequency (Hz) X the scheduled frequency in the Interconnection.

β = Frequency bias setting (MW/0.1 Hz) X the bias value used by the CONTROL AREA.

10 = A constant to convert the frequency bias setting to MW/Hz.

The following apply to the ACE equation for the Western INTERCONNECTION:

s = 1 if t_d is positive and the CONTROL AREA'S accumulation of inadvertent interchange is positive, or if t_d is negative and the CONTROL AREA'S inadvertent interchange is negative.
 $s = 0$ for all other conditions.

β_t = Time error bias (MW/0.1 Second) X the bias value used by the CONTROL AREA to correct for time error. It has the same sign and value as the frequency bias, β .

t_d = Time error (seconds). 1 second maximum.

Area Interchange Error Survey Training Document

B. Area Interchange Error

Area Interchange Error (AIE). The formula for calculating the AIE is the same as the ACE, except that hourly integrated values are used:

$$AIE = (NI_A - NI_S) - 10\beta(F_A - F_S)$$

for the Eastern and Texas INTERCONNECTIONS, and

$$AIE = (NI_A - NI_S) - 10\beta(F_A - F_S) - s(0.3\beta_t T_d)$$

for the Western INTERCONNECTION

where,

NI_A = Actual net interchange (MWh) X the algebraic sum of the energy flows on the CONTROL AREA'S tie lines for the survey period. Positive net interchange is a net energy flow out of the CONTROL AREA.

NI_S = Scheduled net interchange (MWh) X the mutually prearranged intended net energy flow on the CONTROL AREA'S tie lines for the survey period. Positive net interchange is a net energy flow out of the CONTROL AREA.

F_A = Actual frequency (Hz) X the actual average frequency in the INTERCONNECTION for the survey period.

F_S
=

Scheduled frequency (Hz)
X the scheduled average frequency in the Interconnection for the survey period.

β = Frequency bias setting (MW/0.1 Hz) X the bias value used by the CONTROL AREA.

10 = A constant to convert the frequency bias setting to MW/Hz.

The following apply to the AIE equation for the Western INTERCONNECTION:

s = 1 if T_d is positive and the CONTROL AREA'S accumulation of inadvertent interchange is positive, or if T_d is negative and the CONTROL AREA'S inadvertent interchange is negative. $s = 0$ for all other conditions.

β_t
=

Time error bias (MW/0.1 Second)
X
the bias value used by the CONTROL AREA to correct for time error. It has the same sign and value as the frequency bias, β .

T_d = Time error (seconds). 1 second maximum.

C. Survey Procedures

1. **Issuance of Survey.** Surveys will be conducted for periods selected by the chairman or vice chairman of the Resources Subcommittee or designee, on the chairman's or vice chairman's own motion, in response to specific requests from members of the Subcommittee, or when a time error of a magnitude, specified by the Subcommittee, occurs.
 - 1.1. As soon as possible after the survey period is chosen by the chairman, the chairman shall notify the appropriate Subcommittee members by letter of the survey date and hour, average actual frequency during the survey period, and the date for return of survey data.
 - 1.2. Each Subcommittee member shall notify each reporting CONTROL AREA within the Region in writing that a survey is being requested and the average actual frequency during the survey period. The Subcommittee member shall provide for each CONTROL AREA a copy of survey form "NERC Area Interchange Error Survey."
 - 1.3. Each reporting CONTROL AREA shall return one completed copy of the appropriate table to its Subcommittee member. Each Subcommittee member shall review the CONTROL AREA response and send the individual appropriate table results to the NERC staff.
 - 1.4. The NERC staff shall combine the CONTROL AREA data into one report and send one copy to each Subcommittee member.
 - 1.5. Each Subcommittee member shall be responsible for reproducing and distributing the summary report within their Region.
2. **Instructions for AIE Survey for Eastern and ERCOT INTERCONNECTIONS – AIE Form 1**

The line-by-line instructions for the survey form follow:

- Line 1: Enter the date and period of the survey (this information is provided by the Resources Subcommittee member's survey request) and the name of the CONTROL AREA.
- Line 2: Enter the name of all CONTROL AREAS with which interchange occurred at the time of the survey. Use additional forms if necessary.
- Line 3: Enter the mutually agreed upon actual interchange that occurred with each utility for the time of survey; total the entries and place the result in the NET TOTAL column.
- Line 4: Enter the mutually agreed upon scheduled interchange with each utility for the time of the survey; total the entries and place the result in the NET TOTAL column. Sign convention for net power into the CONTROL AREA is negative (–), and net power out of the CONTROL AREA is positive (+). Do not include scheduled inadvertent payback on this line.
- Line 5: Enter all mutually agreed upon scheduled inadvertent payback with each utility for the time of the survey; total the entries and place the result in the NET TOTAL column. These entries reflect only the portion of the total scheduled interchange with each utility that was used for inadvertent payback. Line 4 + Line 5 = Scheduled Net Interchange, NI_S .

Area Interchange Error Survey Training Document

C. Survey Procedures

- Line 6: Enter the inadvertent interchange (Line 3 – Line 4 – Line 5) occurring with each utility at the time of the survey; total the entries and place the result in the NET TOTAL column.
- Line 7: The computed interconnected system frequency error is the value furnished in the survey request letter. Enter the given value here. The given value was computed by taking the difference between the average frequency and the scheduled frequency for the hour being surveyed.
- Line 8: Enter the CONTROL AREA'S bias setting. If using a variable bias, enter the integrated bias for the hour.
- Line 9: Enter the CONTROL AREA bias obligation. $\text{Line 9} = \text{Line 7} \times \text{Line 8} \times 10.0$.
- Line 10: Enter all unilateral inadvertent payback that is *not* scheduled with any utility at the time of survey, as in accordance with NERC Operating Guide I.F. (Systems Control – Inadvertent Interchange Management).
- Line 11: Enter the adjusted Area Interchange Error. $\text{Line 11} = \text{Line 6 Net Total} - \text{Line 9} - \text{Line 10}$.
- Line 12: Enter the average ACE (with correct sign) for each of the six ten-minute periods of the hour. (This is the same as the values reported in the CPC survey, except that here it includes the sign.)
- Remarks: Please attach a separate sheet with any comments regarding the survey and unusual conditions that may have caused your regulating error.

3. Instructions for AIE Survey for Western INTERCONNECTION – AIE Form 2

The line-by-line instructions for the survey form follow:

- Line 1: Enter the date and time of the survey (this information is provided by the Resources Subcommittee member's survey request), and the name of the CONTROL AREA.
- Line 2: Enter the name of all utilities with which interchange occurred at the time of the survey. Use additional forms if necessary.
- Line 3: Enter the mutually agreed upon actual interchange that occurred with each utility at the time of survey; total the entries and place the result in the NET TOTAL column.
- Line 4: Enter the scheduled interchange with each utility at the time of the survey; total the entries and place the NET result in the NET TOTAL column. Sign convention for net power into the CONTROL AREA is negative (–), and net power out of the CONTROL AREA is positive (+). Do not include scheduled inadvertent payback on this line.
- Line 5: Enter all mutually agreed upon scheduled inadvertent payback with each utility at the time of the survey; total the entries and place the result in the NET TOTAL column. These entries reflect only the portion of the total scheduled interchange with each utility that was used for inadvertent payback. $\text{Line 4} + \text{Line 5} = \text{Scheduled Net Interchange, NI}_S$.

Area Interchange Error Survey Training Document

C. Survey Procedures

- Line 6: Enter the inadvertent interchange (Line 3 – Line 4 – Line 5) occurring with each utility at the time of the survey; total the entries and place the result in the NET TOTAL column.
- Line 7: The computed interconnected system frequency error is the value furnished in the survey request letter. Enter the given value here. The given value was computed by taking the difference between the average frequency and the scheduled frequency for the hour being surveyed.
- Line 7a: The computed interconnected time error is the value furnished in the survey request letter. Enter the value here.
- Line 8: Enter the CONTROL AREA'S bias setting. If using a variable bias, enter the integrated bias for the hour.
- Line 9: Enter the CONTROL AREA bias obligation to correct frequency. $\text{Line 9} = \text{Line 7} \times \text{Line 8} \times 10.0$.
- Line 9a: Enter the control bias obligation to correct time error. $\text{Line 9a} = \text{Line 7a} \times \text{Line 8} \times 0.1$.
- Line 10: Enter all unilateral inadvertent payback that is *not* scheduled with any utility at the time of survey, as in accordance with NERC Operating Guide I.F. (Systems Control X Inadvertent Interchange Management).
- Line 11: Enter the Area Interchange Error. $\text{Line 11} = \text{Line 6 Net Total} - \text{Line 9} - \text{Line 9a} - \text{Line 10}$.
- Line 12: Enter the average ACE (with correct sign) for each of the six 10-minute periods of the hour. (This is the same as the values reported in the CPC survey, except that here it includes the sign.)
- Remarks: Please attach a separate sheet with any comments regarding the survey and unusual conditions that may have caused your regulating error.

D. Survey Review

1. **Survey Analysis.** Each NERC Resources Subcommittee member shall cross check all input data and analyze the ACE survey results for the CONTROL AREAS within the Region for uniformity, completeness, and compliance to the instructions.
2. **Survey Review.** The NERC Resources Subcommittee may request comments from Regions or CONTROL AREAS relating the causes of excessive ACE and AIE within a CONTROL AREA.

**North American Electric Reliability Council
Area Interchange Error Survey
Eastern and ERCOT Interconnections**

Form AIE 1

1. Date:	Hr. Ending (CST/CDT):	Control Area:
		Region:

INTERCHANGE DETAILS (All values in MWh)											
2. Control Area or Interconnection											Total
3. Actual Interchange											
4. Scheduled Interchange											
5. Scheduled Inadvertent Payback											
6. Inadvertent Interchange											

AREA INTERCHANGE CALCULATION		
7. Computed Frequency Deviation		Hz
8. Frequency Bias Setting	-	MW/0.1 Hz (negative value)
9. Bias Obligation		MWh Line 7 x Line 8 x 10.0
10. Unilateral Inadvertent Payback		MWh
11. Adjusted Area Interchange Error		MWh Line 6 Total – Line 9 – Line 10

	1	2	3	4	5	6	Total	Avg
12. Integrated ACE for the 6 consecutive Periods of the survey hour	:00-:10	:10-:20	:20-:30	:30-:40	:40-:50	:50-:60		Total/6

Notes:
List remarks on separate sheet of paper, including conditions causing regulating errors. Net power delivered *out* of a CONTROL AREA (over-generation) is positive (+). Net power received *into* a CONTROL AREA (under-generation) is negative (-).

References

Approved by the
Operating Committee
June 15, 2010

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Performance Standards Reference Guidelines

Version 1

to ensure
the reliability of the
bulk power system

June 2010

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Chapter 1 – General [Area Interchange Error Training Document – ACE Equation]

This reference document is intended to provide the reader with a better understanding of the balancing-related standards. While the information can provide clarity on potential ways to demonstrate compliance, the document should not be used by compliance staff as a benchmark to measure compliance or create new obligations not found in the standards. Should any difference or conflict be found between this document and the standards, the standards take precedence.

General [Area Interchange Error Training Document – ACE Equation]

This document provides instructions for calculating the control performance of the balancing authority (BA) and instructions and forms to complete the surveys. It is intended to serve industry participants as a “how to” guide for application and interpretation of the performance standards.

The BA’s Area Control Error (ACE) is the basis for the calculation of control parameters used to evaluate control performance. ACE is used to determine a BA’s control performance with respect to the BA’s impact on system frequency. The value of ACE to be used throughout the calculation of control parameters is directed by standards to reflect its actual value and exclude short excursions due to transient telemetering problems or other influences such as control algorithm actions. Erroneous readings such as “spikes” due to telemetering error or other false influences should be excluded from the calculations. However, the computations should include ALL of the non-erroneous intervals (i.e., do not exclude intervals that contain disturbance conditions). This ACE is defined as net actual interchange less net scheduled interchange less frequency bias contribution and meter error. It does not include offsets (e.g., unilateral inadvertent payback, WECC’s automatic time error correction, etc.).

These measurements of control performance apply to all conditions (i.e., both normal and disturbance conditions). The BA continuously monitors its control performance and reports the compliance results at the end of each month.

Targeted Frequency Bounds

The targeted frequency bounds, epsilon 1 (ϵ_1) and epsilon 10 (ϵ_{10}), are based on historic measured frequency error. These bounds, typically in millihertz (mHz), embody the targeted frequency characteristics used for developing the Control Performance Standard. Each Interconnection is assigned its own frequency bounds.

The Targeted Frequency Bound for an Interconnection is computed as follows:

1. The NERC Resources Subcommittee (RS) defines a desired frequency profile.
2. The NERC RS collects frequency data from designated providers within each Interconnection. The frequency bounds are the RMS of the one- and ten-clock-minute averages of the frequency error (deviation) from schedule. These values are derived from

data samples over a given year. The NERC RS calculates and then sets the targeted frequency bounds, ϵ_1 and ϵ_{10} , to recognize the desired performance profile of frequency for each Interconnection.

Compliance for BAs

A BA that does not comply with CPS is not providing adequate regulation services.

1. If a BA does not comply with the CPS, the BA is not permitted to provide regulation or other services related to control performance for any other BA(s) or other entities.
2. A BA failing to comply is directed by the standard to take immediate corrective action and achieve compliance within three months. If necessary, a BA is directed by the standard to buy sufficient supplemental regulation to achieve compliance.

Compliance for BAs Providing Regulation

A BA is not permitted to provide regulation or other services related to control performance for (an) other BA(s) or other entities external to that BA, if the former BA does not comply with the CPS.

Compliance for BAs Participating in Supplemental Regulation

A BA providing or receiving supplemental regulation will continue to be evaluated on the characteristics of its own ACE with the supplemental regulation service included. The compliance calculations for each of the affected BAs will not change.

Compliance for BAs Participating in Overlap Regulation

- **BAs Providing Overlap Regulation**

A BA providing overlap regulation is to continue to be evaluated on the characteristics of the combined areas' ACE. The provider BA should calculate and use the sum of the frequency bias characteristics of itself and the BA for which it is providing the overlap regulation. Frequency bias minimums apply to each BA individually in these cases.

- **BAs Receiving Overlap Regulation**

A BA receiving overlap regulation service is not to have its control performance evaluated.

Chapter 2 – Control Performance Standard 1, CPS1 [Area Interchange Error Training Document – ACE Equation]

Control Performance Standard 1, CPS1 [Area Interchange Error Training Document – ACE Equation]

CPS1 provides the BA with a frequency-sensitive evaluation of how well its demand requirements were met. The measure is not designed to be a visual indicator that an operator would use to control system generation, nor is it designed to address the issue of unscheduled power flows, or control of inadvertent interchange.

Metrics

Over a given period, the average of the clock-minute averages of a BA's [ACE divided by ten times its bias] times the corresponding clock-minute averages of the Interconnection's frequency error is to be less than or equal to a constant (epsilon 1 squared, the constant on the right-hand side of the following inequality):

$$AVG_{Period} \left[\left(\frac{ACE_i}{-10B_i} \right)_1 * \Delta F_1 \right] \leq \epsilon_1^2 \quad or \quad \frac{AVG_{Period} \left[\left(\frac{ACE_i}{-10B_i} \right)_1 * \Delta F_1 \right]}{\epsilon_1^2} \leq 1$$

where: ACE_i is the clock-minute average of ACE (as ACE is defined in Section A) and B_i is the frequency bias of the BA. For those areas with variable bias, an accumulation of $ACE/(-10B_i)$ is made through the AGC cycles of a minute, and the averaged value at the end of the minute should be saved as the clock-minute value of $ACE_i/(-10B_i)$, ϵ_1 in Hz, is a constant derived from the targeted frequency bound. It is the targeted RMS of one-minute average frequency error from a schedule based on frequency performance over an averaging period of a year. The bound is the same for every BA within an Interconnection.

ΔF_1 (delta F sub one) in Hz, is the clock-minute average of frequency error from schedule, $\Delta F = F_a - F_s$, where F_a is the actual (measured) frequency and F_s is scheduled frequency for the Interconnection.

i is representative of the individual BA,

Period is defined as:

- a. one year for BA evaluation
- b. one month for reporting and Resources Subcommittee review

Compliance

The fundamental measurement for CPS1 is that performance, as measured by percentage compliance, needs to be at least 100%.

It is possible for CPS1 percentage compliance to vary from –infinity to +infinity, depending on delta F and ACE magnitudes.

Control Compliance Rating = Pass if CPS1 ≥ 100%
Control Compliance Rating = Fail if CPS1 < 100%

CPS1 begins with a fundamental calculation called the compliance factor (CF). Its basic building block (called CF', or CF prime to distinguish it from CF as used later) is the quantity defined below, which essentially converts ACE to a form of frequency which can be compared with interconnection epsilon(s).

$$CF' = \left[\left(\frac{ACE}{-10B} \right) * \Delta F \right] \text{ Hz}^2$$

Note: that as written above this quantity is an instantaneous value, no averaging involved. CPS1 uses a 1-minute average base calculation, so CF' becomes

$$CF'_{\text{clock-minute}} = \left[\left(\frac{ACE}{-10B} \right)_{\text{clock-minute}} * \Delta F_{\text{clock-minute}} \right] \text{ Hz}^2$$

Note the units of this calculation are in terms of frequency squared. This is important in the calculations to follow, as comparison is made to epsilon squared to determine compliance.

The compliance factor, CF, is derived from CF' by dividing by epsilon squared:

$$CF = \frac{CF'}{(\epsilon_1)^2}$$

CF is a (dimensionless) ratio that defines whether a BA's contribution to frequency deviation "noise" is greater than or less than the amount allowed. A value of 1 means exactly the amount of allowed frequency deviation-coincident "noise" has been contributed by the BA. Less than 1 means a "quieter" ACE characteristic. Negative means the BA is actually anticoincident with frequency deviation; generally a good thing as long as ACE magnitude is kept in check and the BA is not seriously over-controlling.

CPS1 then converts CF to a compliance percentage as follows:

$$CPS1\% = (2 - CF) * 100\%$$

This calculation is for any time interval. For compliance purposes, CPS1 percentage is calculated over the most recent 12 months (the month of the report plus the most recent 11 consecutive prior months). Epsilon can change, but since CPS1 is reported monthly, and epsilon would normally not be changed except on a month boundary, it is valid to calculate the monthly and the running 12-month CPS1 compliance as follows:

$$CPS1\%_{\text{month}} = (2 - CF_{\text{month}}) * 100\%$$

where:

$$CF_{\text{month}} = \frac{CF'_{\text{month}}}{(\epsilon_1)^2} \quad \text{and} \quad CF'_{\text{month}} = \frac{\sum (CF_{\text{clock-minute}})}{[n_{\text{1min. periods in month}}]}$$

$$\text{CPS1\%}_{12\text{-month}} = (2 - CF_{12\text{-month}})$$

where:

$$CF_{12\text{-month}} = \frac{\sum_{m=1}^{12} [CF_{\text{month}} \times n_{\text{1min. periods in month } m}]}{\sum_{m=1}^{12} n_{\text{1min. periods in month } m}}$$

“ $n_{\text{1 min. periods in month } m}$ ” means the number of valid periods in the month (m), as described later herein. The reason for the 12-month calculation (running 12-month compliance) being different is to allow for possible changes to epsilon 1. It would be undesirable to retroactively change previous months’ measured performance by using a different epsilon than was in effect for them originally. Also note that compliance percentages can be calculated for other time periods (month, day, shift hours, etc.) by replacing $CF_{12\text{-month}}$ in the above formula with the appropriate CF value.

Clock-minute average calculations

A clock-minute average is the average of the reporting BA’s valid measured variable (i.e., for ACE and for frequency error, as well as for the BA’s frequency bias, as defined above) for each valid sample during a given clock minute.

$$\left(\frac{ACE}{-10B} \right)_{\text{clock-minute}} = \frac{\sum_{\text{samples in clock-minute}} \left[\frac{ACE}{-10B} \right]}{n_{\text{samples in clock-minute}}}$$

or, for a BA with constant Bias

$$\left(\frac{ACE}{-10B} \right)_{\text{clock-minute}} = \frac{\left(\frac{\sum_{\text{samples in clock-minute}} ACE}{n_{\text{samples in clock-minute}}} \right)}{-10B}$$

and

$$\Delta F_{\text{clock-minute}} = \frac{\sum_{\text{samples in clock-minute}} \Delta F}{n_{\text{samples in clock-minute}}}$$

The BA’s clock-minute Compliance Factor (CF) becomes:

$$CF_{\text{clock-minute}} = \left[\left(\frac{ACE}{-10B} \right)_{\text{clock-minute}} * \Delta F_{\text{clock-minute}} \right]$$

Accumulated Averages

The reporting entity can calculate and store compliance factors for a number of different reporting/analysis intervals. These factors can be used to calculate a CPS1 percentage for any desired time interval for any purpose desired.

for a single hour:
$$CF_{\text{clock-hour}} = \frac{\left[\sum CF_{\text{clock-minute}} \right]_{\text{valid clock-minute averages in hour}}}{n_{\text{valid clock-minute averages in hour}}}$$

for a month:
$$CF_{\text{month}} = \frac{\sum_{\text{hours-in-month}} [(CF_{\text{clock-hour}})(n_{\text{valid clock-minute averages in hour}})]}{\sum_{\text{hours-in-month}} [n_{\text{valid clock-minute averages in hour}}]}$$

for (running) 12 months:
$$CF_{12\text{-month}} = \frac{\sum_1^{12} (CF_{\text{month}})(n_{\text{valid clock-minute averages in month}})]}{\sum_1^{12} [n_{\text{valid clock-minute averages in month}}]}$$

Interruptions in Data

In order to ensure that the average ACE and Frequency Deviation calculated for any one-minute interval is representative of that one-minute interval, it is necessary that at least 50% of both ACE and Frequency Deviation sample pairs during that one-minute interval be present. The data pairs within a one-minute period need not be contiguous, but ACE and frequency data pairs should be simultaneous. Should an interruption in the recording of ACE or Frequency Deviation due to uncontrollable causes result in a one-minute interval not containing at least 50% of sample pairs of both ACE and Frequency Deviation, that one-minute interval is excluded from the calculation of CPS1.

Examples

Below is an example of the calculations needed for CPS1 monitoring and compliance. The example starts with the first hour of the first day of a month through to the end of the month, and the BA bias, B = -60 MW/0.1 Hz.

On Day 1, at the beginning of HE 0100, the area should calculate CF' clock-minute by multiplying the clock-minute average ACE (divided by ten times the area's bias) by the clock-minute average frequency error from schedule. Subsequent products are calculated for the remaining clock-minutes of the hour.

HE 0100:		Minute 1	Minute 2	...	Minute 60	Sum	CF' clock-hour = Σ(CF')/n
ACE	MW	-20	-10		-40		
ACE/-10B	Hz	-20/-10(-60) = .0333332	.01666670666667		

Chapter 2 – Control Performance Standard 1, CPS1 [Area Interchange Error Training Document – ACE]

ΔF	Hz	0.005	-0.005	...	0.005		
$CF' = (ACE/-10B) \times \Delta F$	Hz^2	-0.000167	0.000083	...	-0.000333	0.00525	0.000088 or 88 mHz^2
n = (# of 1-min averages)		1	1		1	60	

Note that n (# of 1-minute sample averages) is based on the number of valid samples over the hour. Since CPS1 uses 1-minute averages of ACE and frequency error (and there were no data anomalies in this hour), n = 60. The procedure shown above is repeated for each of the 24 hourly periods of each day. As the days of the month continue, the 24-hour period CF' clock-hour average-month values are averaged as shown below: At the end of the month, a CF'month can be calculated.

Hour		Day 1	Day 2	...	Day 31	Sum	$CF'_{clock-hour\ average-month} = [\Sigma(CF' \times n)]/\Sigma(n) \text{ mHz}^2$
HE 0100	$CF'_{clock-hour}$	87.5	93.5	...	92.0		90.5
	n (# of averages)	60	59		57	1842	
	$CF'_{clock-hour} \times n$	5250	5516.5		5244	166,742	
HE 0200	$CF'_{clock-hour}$	90.0	85.0	...	89.5		87.5
	n	58	60		60	1830	
	$CF'_{clock-hour} \times n$	5220	5100		5370	160,170	
...
HE 2400	$CF'_{clock-hour}$	89.0	92.0	...	89.0		89.5
	n	60	59		59	1830	
	$CF'_{clock-hour} \times n$	5340	5428		5251	163,787	
	Total n					44,208	
	Total $CF'_{clock-hour\ average-month} \times n$					3,930,888	
	$CF'_{month} =$						88.9 mHz^2
	$\Sigma(CF'_{clock-hour\ average-month} \times n) / \Sigma(n)$						

A rolling CF12-month

CF 12-month can be calculated using the CFmonth values.

	Month				Year	Year
	1	2	..	12	Sum	$CF'_{12-month}$
CF'_{month}	88.9	93.3	..	91.7		$[\Sigma(CF'_{month} \times n) / \Sigma(n)] =$ 91.3 mHz^2
n	44,208	42,072	·	42,875	515,030	
$CF'_{month} \times n$	3,930,888	3,925,345		3,931,655	47,022,239	

Assuming this interconnection has a \square 1 of 10 mHz, then the CPS1 compliance percentage would be calculated as follows:

$$CF = CF'_{12\text{-month}} / (\epsilon_1)^2 = 91.3 \text{ mHz}^2 / (10)^2 \text{ mHz}^2 = 91.3 / 100 = .913$$

$$CPS1 \% = (2 - CF) \times 100\% = (2 - .913) \times 100\% = (1.087) \times 100\% = 108.7\%$$

This results in a “passing” grade (12-month CPS1 should be at least 100%).

Surveys

Performance Standard surveys are conducted monthly to analyze and demonstrate each BA’s level of compliance with the Control Performance Standards. Completed surveys should be provided each month, to the designee or portal representing the Region, by the tenth working day of the month following the month reported. Users should check with regions to determine reporting requirements.

Instructions for BA Survey

Using data derived from digital processing of the ACE signal, a representative from each BA will complete and submit CPS1 Form 1, “NERC Control Performance Standard Survey.” Hourly Table - Report the clock-hour average compliance factor (CF) for each of the 24 hourly periods and the total number of clock-minute sample averages in each clock-hour average.

CPS1 Standard Summary

CPS1	CPS1 Month	Report the monthly compliance factor, percent compliance, and number of clock-minute sample averages and enter in this cell. This value is for the month, only and is critical to correct evaluation of 12-month compliance.
	CPS1 Rolling 12 Month Value	Report the rolling 12-month compliance factor, percent compliance, and number of samples and enter in this cell. This is your calculation of the rolling compliance. NERC will also make the calculation based on your monthly submittals.
	Number of Valid Samples	Enter number of valid clock-minute averages in the profile hour and total.
	Unavailable Periods	Enter number of unavailable 1-min periods in the profile hour and column total.

Chapter 3 – Instructions for Regional and NERC Surveys

Instructions for Regional and NERC Surveys

From a review of the BAs' surveys, each Regional Survey Coordinator or RS member will ensure completion of CPS1 Form 2, "NERC Control Performance Standard — Regional Summary."

- a. Review CPS1 Form 1 data received from each BA in the Region for uniformity, completeness, and compliance with the instructions. Iterate with BA survey coordinators where necessary.
- b. Transfer the data from each Form to the appropriate columns on CPS1 Form 2 or its equivalent. Review the comments submitted and, if significant, identify them with the appropriate BAs.
- c. Ensure forwarding of a copy each of the completed CPS Forms 1 and 2 or their equivalent to the NERC staff.

NERC staff will combine the Regional reports into a single summary report to be reviewed quarterly by the NERC Resources Subcommittee.

NERC Control Performance Standard Survey						
CPS1 Form 1		BA -				
Region -		Month -		Time Zone		
ϵ_1 -		Year -		-		
H.E.	CF	%	# of Valid 1-min Averages	Unavailable Periods		
0100				Record the total month's number of valid 1-min sample averages from each of the 24 hourly profile periods	Record the total unavailable periods from each of the month's 24 hourly profile periods	
0200						
0300						
0400						
0500						
0600						
0700						
0800						
0900						
1000						
1100						
1200						
1300						
1400						
1500						
1600						
1700						
1800						
1900						
2000						
2100						
2200						
2300						
2400						
CPS1 Month -						
CPS1 – Rolling 12 Month Value						

Chapter 4 – Control Performance Standard 2, CPS2

Control Performance Standard 2, CPS2

The second measure of the CPS survey is designed to bound ACE ten-minute averages and in doing so provides a means to limit excessive unscheduled power flows that could result from large ACEs.

Metrics

Over a given period, the clock ten-minute averages of a BA's ACE should be less than the constant on the right-hand side of the following inequality during at least a percentage of the period as specified herein:

$$AVG_{10\text{-minute}}(ACE_i) \leq L_{10}$$

where: $L_{10} = 1.65 \epsilon_{10} \sqrt{(-10B_i)(-10B_s)}$

ϵ_{10} in Hz, is a constant derived from the targeted frequency bound. It is the targeted RMS of ten-minute average frequency error from schedule based on a selected historical period of interconnection frequency performance. The bound, ϵ_{10} , is the same for any BA within an Interconnection. In the ideal, it is also equal to epsilon1 divided by the square root of 10.

1.65 is a constant used to convert the frequency target to 90% probability. It is the number of standard deviations from the mean of a statistical normal distribution (Gaussian distribution) that will result in a probability of noncompliance of 10% (i.e., compliance of 90%).

B_i in (negative) MW per tenth Hz, is the frequency bias of the BA.

B_s in (negative) MW per tenth Hz, is the sum of the frequency bias settings of the BAs in the respective Interconnection; for systems with variable bias, this is equal to the sum of the minimum frequency bias settings.

For those systems with variable bias, CPS2 becomes:

$$AVG_{10\text{-minute}}(ACE) \leq L_{10}$$

where:

$$L_{10} = 1.65 \epsilon_{10} [-10AVG_{10\text{-minute}}(B_i)] \sqrt{\frac{B_s}{B_{\text{minimum}}}}$$

B_{minimum} is the area's minimum allowed bias.

Compliance

CPS2 compliance is achieved if the 10-minute ACE averages satisfy the inequality above for 90% (or more) of the intervals in a calendar month. The percentage, described below, is referred to as the CPS2 compliance percentage, or CPS2%.

$$\text{Control Compliance Rating} = \text{Pass} \quad \text{CPS2\%} \geq 90\%$$

$$\text{Control Compliance Rating} = \text{Fail} \quad \text{CPS2\%} < 90\%$$

The compliance percentage is calculated as follows:

$$\text{CPS2\%} = \left[1 - \frac{\text{Violations}_{\text{month}}}{(\text{Total Periods}_{\text{month}} - \text{Unavailable Periods}_{\text{month}})} \right] * 100$$

The $\text{Violations}_{\text{month}}^1$ are a count of the number of periods in which the average $\text{ACE}_{\text{clock-ten-minutes}}$ exceeded L_{10} . $\text{ACE}_{\text{clock-ten-minutes}}$ is the sum of valid ACE samples within a clock-ten-minute period divided by the number of valid samples (average ACE).

The $\text{Violations}_{\text{month}}^2$ are a count of the number of periods in which the average $\text{ACE}_{\text{clock-ten-minutes}}$ exceeded L_{10} . $\text{ACE}_{\text{clock-ten-minutes}}$ is the sum of valid ACE samples within a clock-ten-minute period divided by the number of valid samples (average ACE).

$$\text{Violation}_{\text{clock-ten-minutes}} = 0 \text{ if } \left| \frac{\sum \text{ACE}}{n_{\text{samples in 10-minutes}}} \right| \leq L_{10}$$

$$= 1 \text{ if } \left| \frac{\sum \text{ACE}}{n_{\text{samples in 10-minutes}}} \right| > L_{10}$$

Each area reports the total number of Violations and Unavailable Periods for the month.

Determination of Total Periods_{month} and Violations_{month}

Since the CPS2 Criterion says that ACE is averaged over a discrete time period, the same factors that limit $\text{Total Periods}_{\text{month}}$ will limit $\text{Violations}_{\text{month}}$. The calculation of $\text{Total Periods}_{\text{month}}$ and $\text{Violations}_{\text{month}}$, therefore, must be discussed jointly.

¹ Violation in the context of CPS2 means exceeding the L10 limit for one of the 6 ten-minute periods in a clock hour. There is no NERC compliance violation unless a Balancing Authority exceeds the L10 limit more than 10% of the ten-minute periods in the month.

² Violation in the context of CPS2 means exceeding the L10 limit for one of the 6 ten-minute periods in a clock hour. There is no NERC compliance violation unless a Balancing Authority exceeds the L10 limit more than 10% of the ten-minute periods in the month.

Each 24-hour period beginning at 0000 and ending at 2400 contains 144 discrete ten-minute periods (six periods more or less on Daylight Saving Time transition days). Each hour (HH) contains six discrete ten-minute periods, where period 1 spans HH:00⁺ – HH:10, period 2 spans HH:10⁺ – HH:20, period 3 spans HH:20⁺ – HH:30, period 4 spans HH:30⁺ – HH:40, period 5 spans HH:40⁺ – HH:50, and period 6 spans HH:50⁺ – (HH+1):00. For a system that samples ACE every four seconds, for example, the average ACE over a ten-minute period would be defined by the algebraic sum of 150 ACE samples (starting at HH:00:04 and ending at HH:10:00) divided by 150.

A CPS2 violation is recorded for any valid ten-minute period where the absolute value of average ACE is greater than L_{10} .

Chapter 5 – Interruption in the Recording of ACE – Valid Intervals

Interruption in the Recording of ACE – Valid Intervals

A condition may arise which may impact the normal calculation of Total Periods_{month} and Violations_{month}. This condition is a sustained, unavoidable and uncontrollable interruption in the recording of ACE or one of its components.

In order to ensure that the average ACE calculated for any ten-minute interval is representative of that ten-minute interval, it is necessary that at least half the ACE data samples are present for that interval. The samples need not be contiguous. Such a period is a valid interval. Should more than half of the ACE data be unavailable due to loss of telemetering or computer unavailability, that ten-minute interval is not valid and is omitted from the calculation of CPS2.

Data Reporting

The BA is responsible for submitting the Control Performance Standard survey each month. In addition, the BA is responsible for retaining sufficient pertinent data that will enable reproduction of the performance calculations.

Figure 1 -- CPS2-L10 Compliance Calculation Examples

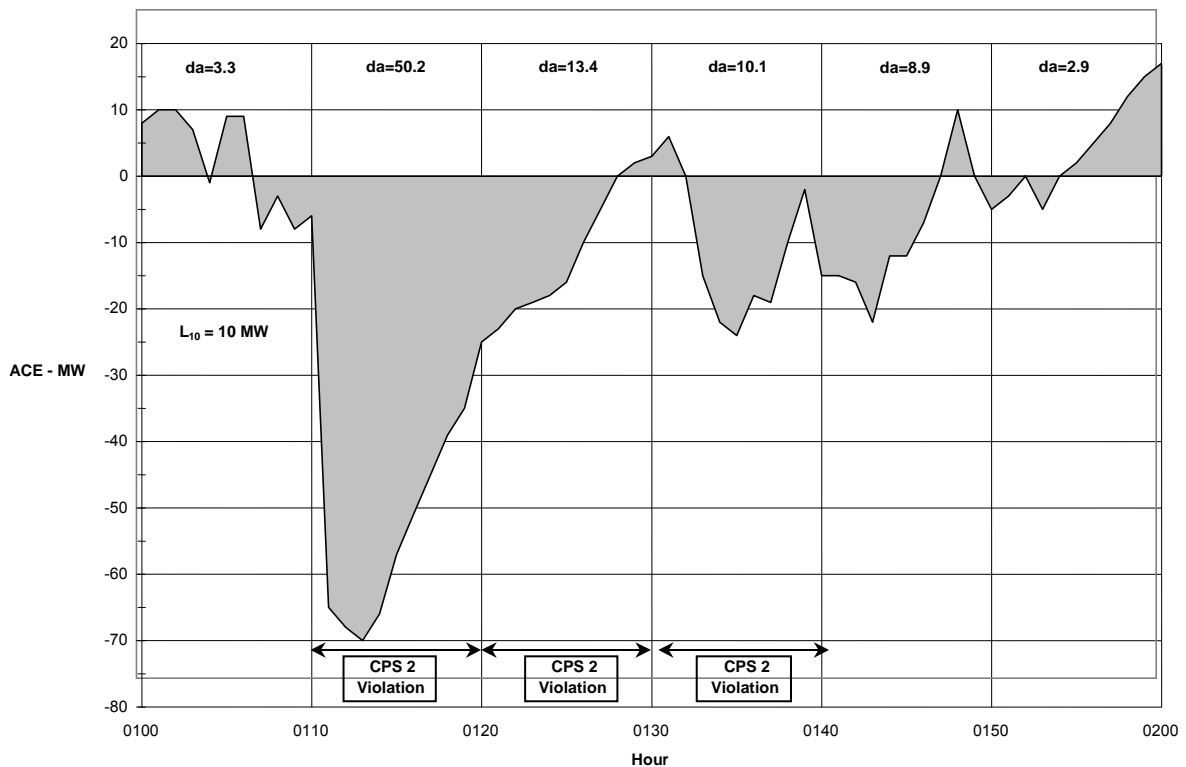


Figure 1 demonstrates various examples of CPS2 compliance determination. Note that Figure 1 is separated into six distinct clock-ten-minute periods. The absolute value of the algebraic mean of the ACE during each period, referred to as d_a , is compared to L10 (10 MW for this system) to

determine if there has been a violation for that period. Note that the fourth interval (0130 – 0140) has recorded a violation because the absolute value of the algebraic mean of 10.1 MW exceeds the L10 of 10 MW. Since disturbance conditions are included in the CPS2 calculation, violations are also recorded for the second and third intervals (0110–0120 & 0120–0130).

Figure 2 -- CPS2-L10 Compliance & Data Interruption Effects

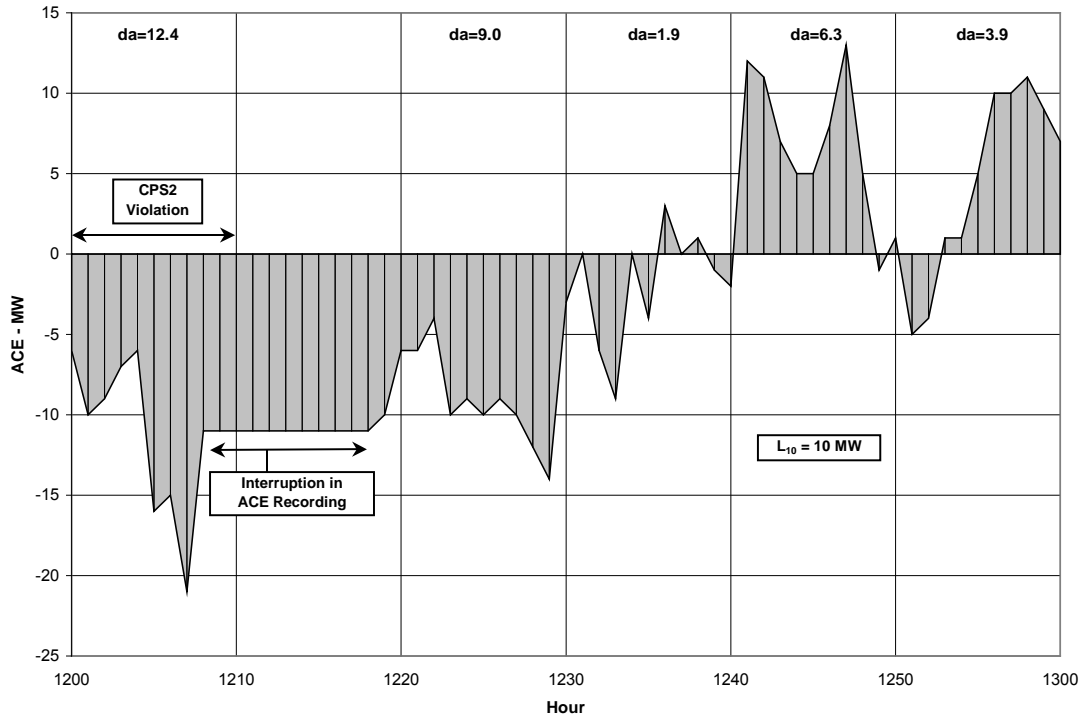


Figure 2 demonstrates various examples of L10 compliance coupled with an interruption in the recording of ACE. At 1208, ACE recording was interrupted and not returned until 1218. Since the ACE recording for the interval 1210 – 1220 did not include at least five minutes of data, this period is eliminated from CPS compliance analysis. In contrast, the first ten-minute interval of 1200 – 1210 is included in the analysis because ACE recording was interrupted only for the last two minutes of the interval. In fact, the first interval is in violation because the absolute algebraic mean of 12.4 MW exceeds the L_{10} of 10.0 MW. This algebraic mean of 12.4 MW was calculated for the eight minutes during which ACE was not interrupted. Thus, for this hour, there was one violation out of five valid intervals.

Surveys

Performance Standard surveys are submitted monthly to analyze and demonstrate each BA’s level of compliance with the Control Performance Standards. Completed surveys are provided each month to the Region by the tenth working day of the month following the month being reported.

Instructions for BA Survey

Each BA will complete and submit CPS2 Form 1, “NERC Control Performance Standard Survey.” For each of the 24 hourly periods of a day, report the monthly total number of CPS2 violations and the number of unavailable ten-minute periods. For example, if there was one

violation for hour ending 0100 every day of a 31-day month, a 31 would be entered for the 0100 hourly period.

CPS2 Standard Summary

CPS2	TOTAL	Sum the number of sample averages, the number of violations, and unavailable ten-minute intervals recorded on the hourly tables and enter the sums in this row for each column.
	CPS2 (%)	Calculate the CPS2 percentage compliance and enter in this row using the formulas and procedures described in Section C.

Instructions for Regional and NERC Surveys

From a review of the BAs’ surveys, each Regional Survey Coordinator or RS member will ensure completion of CPS2 Form 2, “NERC Control Performance Standard — Regional Summary.”

- a. Review CPS2 Form 1 data received from each BA in the Region for uniformity, completeness, and compliance with the instructions. Iterate with BA survey coordinators where necessary.
- b. Transfer the data from each Form to the appropriate columns on CPS Form 2. Review the comments submitted and, if significant, identify them with the appropriate BAs.
- c. Forward a copy each of the completed CPS2 Forms 1 and 2 to the NERC staff.
- d. NERC staff will combine the Regional reports into a single summary report that is reviewed by the NERC Resources Subcommittee quarterly.

NERC Control Performance Standard Survey			
CPS2 Form 1		BA -	
Region -		Month -	
L ₁₀ -		Year -	
H.E. CPT	Violations		Unavailable Periods
0100	Record total violations for each of the 24 hourly profile periods		Record total unavailable periods for each of the 24 hourly profile periods
0200			
0300			
0400			
0500			
0600			
0700			
0800			
0900			
1000			
1100			
1200			
1300			
1400			
1500			
1600			
1700			
1800			
1900			
2000			
2100			
2200			
2300			
2400			
CPS2 Month -			

Chapter 6 – Disturbance Control Standard, DCS

Disturbance Control Standard, DCS

During a disturbance, controls cannot usually maintain ACE within the criteria for normal load variation. Balancing areas, alone or collectively through reserve-sharing groups are expected to activate contingency reserve to cause recovery of ACE magnitude within fifteen minutes following the start of a disturbance. This dictates that a disturbance be defined. A disturbance is a sudden, unanticipated change (contingency) in resource(s) or demand. A sudden change is one that takes place over a minute or less. The DCS focuses on reportable disturbances.

Fifteen minutes is the existing recovery period duration which has evolved from debate over the appropriate way to measure the deployment of what has been measured as 10-minute reserves. It was argued that all balancing authorities need time to assess the validity of what appears to be a disturbance, and reserve-sharing groups need time to propagate calls for contingency reserves. Analyses were undertaken to determine probabilistically how lengthening the recovery period from 10 to 15 minutes would increase exposure to a second contingency. It was determined that the effect was very small, and recoverability from the next contingency is largely driven by reserve restoration timing, anyway. The 15 minute recovery standard was passed for recommendation by the NERC Resources Subcommittee in October, 1999.

For purposes of disturbance control compliance, reportable disturbances are contingencies that are greater than or equal to 80% of the most severe single contingency loss. The start of a disturbance is the time of the event as best defined by resource output decline, breaker opening, or other such indication – in the absence of such indication, the moment of first ACE deflection may be used. The start of the recovery period is the same moment as the start of the disturbance. Note that the start of a disturbance and its magnitude are determined by the resource or demand change, while recovery and compliance are determined by ACE.

Regions may optionally reduce the 80% reporting threshold, provided that normal operating characteristics are not being considered or misrepresented as contingencies. Normal load and generation excursions (e.g., pumped storage hydro, arc furnace, rolling steel mill, etc.) that influence ACE are not reportable disturbance conditions. Normal operating characteristics are excluded because DCS strives to measure the recovery from sudden, unanticipated changes in demand or supply-side resources.

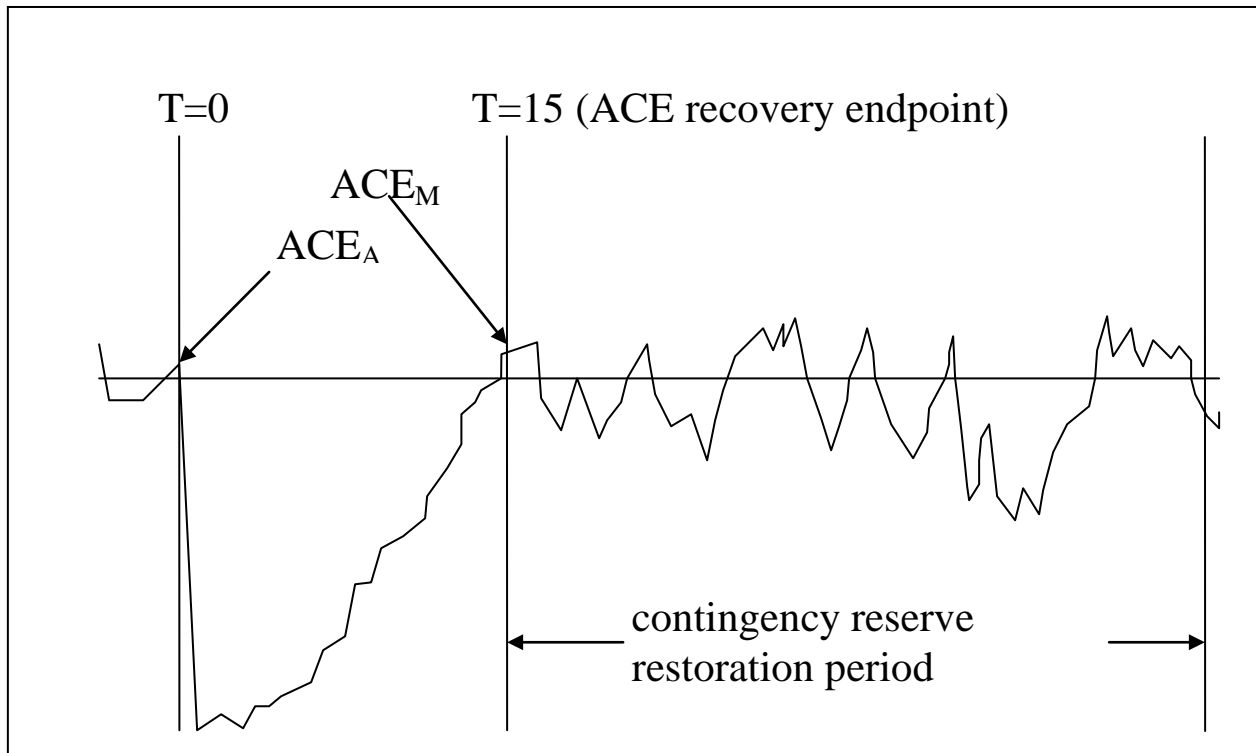
Metrics

Balancing Area

A BA is to return its ACE either to zero or to its pre-disturbance ACE level within a recovery time of fifteen minutes following the start of a disturbance. A BA may, at its discretion, measure its compliance based on the ACE measured fifteen minutes after the start of the disturbance, or on the maximum ACE recovery measured within the fifteen minutes following the start of the disturbance.

Reserve Sharing Group (RSG)

The disturbance control compliance for a BA within an RSG is based on the compliance of the RSG (according to the compliance method chosen). An RSG may, at its discretion, measure this recovery based on the combined ACE measured fifteen minutes after the start of the disturbance, or on the maximum combined coincidental ACE recovery measured within the fifteen minutes following the start of the disturbance event (not the time at which reserve activation was requested).



Relationships among ACE, the 15-minute recovery period, and the reserve restoration period

Compliance

A BA or RSG calculates and reports compliance with the Disturbance Control Standard for all disturbances greater than or equal to 80% of the magnitude of the BA's or the RSG's most severe single contingency loss. Regional Reliability Councils may, at their discretion, specify a lower reporting threshold. Disturbance Control Standard compliance is measured as the percentage recovery, R_i . $R_i \geq 100\%$ represents full compliance.

For loss of generation:

if $ACE_A < 0$

then

$$R_i = \frac{MW_{Loss} - \max(0, ACE_A - ACE_M)}{MW_{Loss}} * 100\%$$

if $ACE_A \geq 0$

then
$$R_i = \frac{MW_{Loss} - \max(0, -ACE_M)}{MW_{Loss}} * 100\%$$

where

MW_{LOSS} is the MW size of the disturbance as measured at the beginning of the event. It is the size of the resource or demand loss, not the ACE deflection,

ACE_A is the pre-disturbance ACE,

ACE_M is the value of ACE representing the point of greatest recovery from the disturbance measured within the fifteen minutes following the start of the disturbance event. A BA or RSG may, at their discretion, set ACE_M = ACE_{15 min}.

a. **Determination of MW_{LOSS}.**

Record the MW_{LOSS} value as measured at the site of the loss to the extent possible. The value should not be measured as a change in ACE since governor response and AGC response may introduce error.

b. **Determination of ACE_A.**

Base the value for ACE_A on the average ACE over the period just prior to the start of the disturbance. Average over a period between 10 and 60 seconds prior and include at least 4 scans of ACE. In the illustration to the right, the horizontal line represents an averaging of ACE for 15 seconds prior to the start of the disturbance with a result of ACE_A = -25 MW.

c. **Determination of ACE_M.**

ACE_M is the value of ACE representing the point of greatest recovery from the disturbance measured within fifteen minutes following the start of the disturbance. It is negative for typical generation loss disturbances where zero is not reached within the recovery interval. At the discretion of the BA or of the RSG, compliance may be based on the ACE measured fifteen minutes following the start of the disturbance, i.e., ACE_M = ACE_{15 min}.

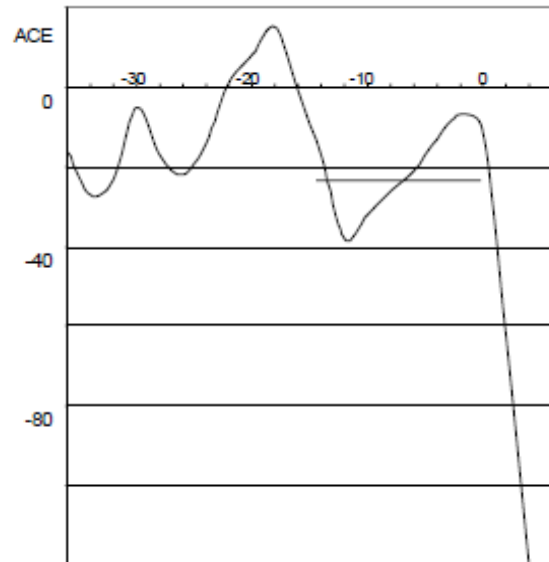
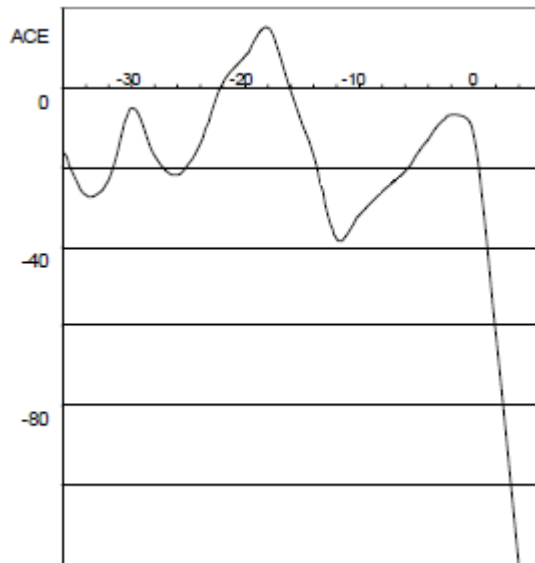


Figure 1 demonstrates compliance evaluation during a disturbance condition (Disturbance Control Standard). Note the pattern of the disturbance condition, which began at 0110, the time at which ACE deflection exceeds this entity's disturbance reporting threshold of 50 MW. During this disturbance, the Disturbance Control Standard was violated because ACE was not restored to its pre-contingency level until 0127 (a 17-minute interval which violates the Disturbance Control Standard).

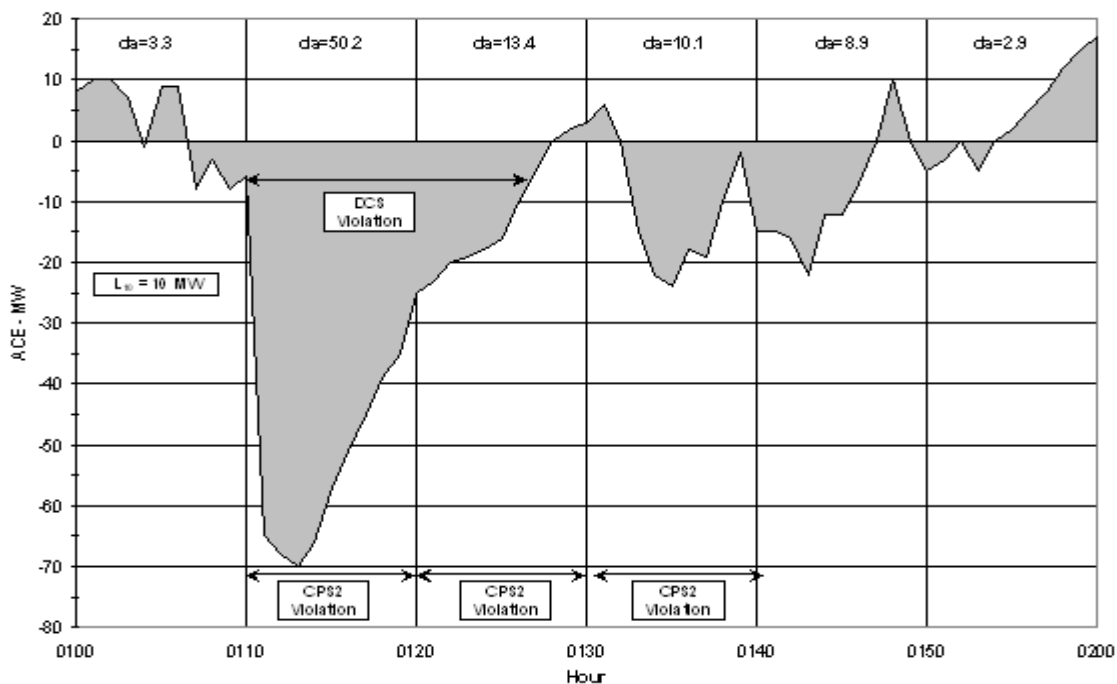


Figure 1 — CPS2-L₁₀ Compliance & Disturbance Control Standard, 2 Disturbance Examples

Reporting

Each BA or RSG is to report its Disturbance Control Standard compliance quarterly. The completed Disturbance Control Standard survey is to be supplied to NERC by the 20th day following the end of the respective quarter. Where RSGs exist, the Regional Reliability Council is to decide either to report these on a BA basis or on an RSG basis. If an RSG has dynamic membership or allocates reserves dynamically, then the Region converts the disturbance reporting for the RSG to a BA basis before reporting to NERC. If a BA basis is selected, each BA reports the RSG's performance only for disturbances occurring in their area.

- **Reportable Disturbance**
The definition of reportable disturbance magnitude is to be provided to NERC by the respective Regional Reliability Councils. The definition is to include events that are greater than or equal to 80% of a BA's or RSG's most severe single contingency. The definition of a reportable disturbance should be specified in the operating Policy adopted by each Regional Reliability Council. This definition may not be retroactively adjusted in response to observed performance.

- a. **Most Severe Single Contingency.** A BA’s most severe single contingency is defined as the magnitude of the largest single credible event that would cause the greatest change in the BA’s ACE, or as defined by the respective Regional Council. It is not necessarily a single loss; it could be an entire generating station, or a loss from transmission facility or facilities contingency.
- b. **Excludable Disturbances and Average Percent Recovery.** The BA or RSG is to report both the number of reportable disturbances that occur in the given quarter, and the average percent recovery for that quarter. The report should also indicate excludable disturbances that occurred in the quarter and the average percent recovery for those excluded events.
- c. **Excludable Disturbance.** An excludable disturbance is a disturbance whose magnitude was greater than the magnitude of the most severe single contingency.
- d. **Average Percent Recovery.** The average percent recovery is the arithmetic average of all the calculated R_i from reportable disturbances during the given quarter. Average percent recovery is similarly calculated for excludable disturbances. (See calculation of R_i below).
- e. **Contingency Reserve Adjustment Factor (CRAF).** The quarterly Contingency Reserve Adjustment factor is to include only those reportable disturbances with magnitudes less than or equal to the magnitude of the respective BA’s most severe single contingency.

CRAF is defined as follows:

when $n_{Quarter} \geq 0$, then

$$CRAF_{Quarter} = 200 - \left[\frac{\sum R_i}{n_{Quarter}} \right]$$

when $n_{Quarter} = 0$, then $CRA_{Quarter} = 100$

where $n_{Quarter}$ is the number of reportable disturbances experienced during the reporting quarter.
 i = reportable disturbances.

R_i is defined in section C.2.

Calculation Precision

The Adjustment Factor is to be rounded off to two decimal places.

Exemptions

Requests for exemptions for single events that cause multiple reportable disturbances (e.g. hurricanes, earthquakes, islanding, etc.) is to be submitted to the NERC Director of Compliance. Until the exemption is approved or denied, the BA or RSG is to consider the request denied.

Contingency Reserve Adjustment Period

BAs are to revise their respective Contingency Reserve Requirement by their computed Contingency Reserve Adjustment factor. The adjustments will be effective starting one month following the end of the reported quarter and remain in effect for three months.

Report Filing

Each BA or RSG is to report its Disturbance Control Standard compliance quarterly, by the 10th working day following the end of the quarter, on Form DCS “NERC Disturbance Control Standard Survey.”

- a. Mail a copy of the completed Form DCS to the NERC staff.
- b. NERC staff will combine the Regional reports into a single summary report and make copies available to each Resources Subcommittee member and others with a legitimate need to know.

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Interchange Reference Guidelines Version 2

RELIABILITY | ACCOUNTABILITY



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Revision Log

Revision Number	Description of changes
1	<ul style="list-style-type: none"> • Original document
2	<ul style="list-style-type: none"> • Added <i>Table of Contents</i> section • Added <i>Revision Log</i> section • Added <i>Introduction</i> section • Added <i>Interchange Terms</i> section • Notated all NERC Glossary terms within the document • Added <i>Interchange Coordinator</i> section • Updated previous section “The Relationship between Interchange Transactions and Interchange Schedules” section into new <i>Interchange Fundamentals</i> section • Added <i>Implementing Interchange</i> section • Added <i>Practical Guide to Interchange Implementation</i> section including references to the e-Tag specifications and schema • Moved and updated previous “Implementing Interchanges Schedules” section to <i>Other Interchange Schedule Concepts</i> subsection • Added <i>A Note on Dynamic Transfers</i> section • Added <i>Consideration for Interchange Involving DC Tie Operator</i> section • Removed previous section “Interchange Schedules within a Multi-Party Regional Agreement or Transmission Tariff”

Introduction

The Interchange Reference Guidelines address and explain the process to implement Interchange. This document is intended to address the following:

1. Defines Interchange terms,
2. Reviews Interchange Transaction and Interchange Schedule concepts,
3. Reviews the theory of implementing Interchange,
4. Reviews the practical processes used to implement Interchange via e-Tag, and
5. Discusses Dynamic Schedules and DC Ties as related to Interchange.

Interchange Terms

NOTE: In this document, the use of the terms are intended to be identical with the NERC “**Glossary of Terms Used in Reliability Standards**” and the NAESB Business Practice Standard WEQ-000 titled “**Abbreviations, Acronyms, and Definition of Terms**”. The definitions listed in the two documents above should prevail if there are any discrepancies. The NERC “**Glossary of Terms Used in Reliability Standards**” is posted at the NERC website in the same location as the Reliability Standards under the link name “**Glossary of Terms**”.

The following terms are used in this document and not defined in standardized industry *Business Practices*:

Market Assessment – The evaluation and verification of the commercial details of *Interchange*.
Market Operator – An entity that is responsible for the implementation of an organized market and submits market adjustments based on market outcomes. A Market Operator must be registered in the Electric Industry Registry (EIR) in order to submit market adjustments.

Wide Area Reliability Tool — This generic term is intended to reflect in a “tool neutral” manner those wide-area reliability assessment tools (such as the *Interchange Distribution Calculator (IDC)* for the Eastern *Interconnection*) acknowledged by NERC as a decision making tool among various reliability entities.

Reliability Assessment – The evaluation and verification of the reliability details of *Interchange*

All terms from the NERC Glossary and defined above are capitalized and italicized in this document. Certain other terms from other locations, such as the e-Tag specification, may be capitalized as well.

Interchange Coordinator

The NERC Functional Model lists the Interchange Coordinator (IC) as the function responsible for communicating *Arranged Interchange* for reliability evaluation and for communicating *Confirmed Interchange* to be implemented between *Balancing Authorities (BAs)*. However, NERC reliability standards refer to the *Interchange Authority (IA)*. These guidelines do not make reference to the *IA* or the *IC*, but instead refers to the *Sink Balancing Authority* as the responsible entity.

Interchange Fundamentals

The Relationship between Interchange Transactions and Interchange Schedules

Purchasing-Selling Entities (PSEs) and in some instances *BAs* “arrange” *Interchange Transactions* by buying and selling energy and capacity and arranging for *Transmission Services*. A compilation of these arranged *Transactions* are forwarded by the *PSE* to the *Sink Balancing Authority*. Reliability entities assess and “approve” or “deny” *Interchange Transactions* based on reliability criteria, arrangements for *Interconnected Operations Services*, and *Transmission* rights. To “implement” the *Interchange Transaction*, all affected reliability entities incorporate the *Interchange Transaction* into their *Interchange Schedules* as explained on the following pages.

In this example, there are three *Interchange Transactions* (IT1, IT2, and IT3) that result in a number of *Interchange Schedules* between *BAs* A, B, C, and D. (Refer to Figure A on the right and Table 1 below. For simplicity, we are ignoring losses.)

Interchange Transaction 1 (IT1)

BA A is the *Source Balancing Authority* for *Interchange Transaction 1 (IT1)*, and *BA B* is the *Sink Balancing Authority*. To make IT1 occur, *BA A* implements an *Interchange Schedule* with *BA B* (S_{AB-IT1}). In this case, the *Source Balancing Authority A* is the *Sending Balancing Authority*, and the *Sink Balancing Authority B* is the *Receiving Balancing Authority*.

Interchange Transaction 2 (IT2)

BA A is also the *Source Balancing Authority* for *Interchange Transaction 2 (IT2)*. *BA D* is the *Sink Balancing Authority* for this *Interchange Transaction*. *B* and *C* are *Intermediate Balancing Authorities*. The resulting *Interchange Schedules* are from *Sending Balancing Authority A* to *Receiving Balancing Authority B* (S_{AB-IT2}), *Sending Balancing Authority B* to *Receiving Balancing Authority C* (S_{BC-IT2}), and *Sending Balancing Authority C* to *Receiving Balancing Authority D* (S_{CD-IT2}).

Interchange Transaction 3 (IT3)

BA C is the *Source Balancing Authority* for *Interchange Transaction 3 (IT3)*, and *BA A* is the *Sink Balancing Authority*. *B* is the *Intermediary Balancing Authority*. To make IT3 occur, *Sending Balancing Authority C* implements an *Interchange Schedule* with *Receiving Balancing Authority B* (S_{CB-IT3}), and *Sending Balancing Authority B* implements an *Interchange Schedule* with *Receiving Balancing Authority A* (S_{BA-IT3}).

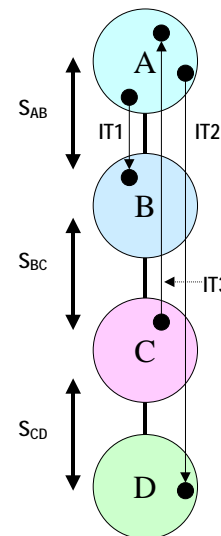


Figure A - Interchange Transactions and Schedules

Net Schedules

BAs A and B can calculate a *Net Interchange Schedule* between these two BAs by adding S_{AB-IT1} and S_{AB-IT2} and S_{BA-IT3} . BAs B and C can calculate a *Net Interchange Schedule* between these two BAs by adding S_{BC-IT2} and S_{CB-IT3} .

The *Net Scheduled Interchange* for A is $S_{AB-IT1} + S_{AB-IT2} + S_{BA-IT3}$. The *Net Scheduled Interchange* for B is $S_{AB-IT1} + S_{AB-IT2} + S_{BA-IT3} + S_{BC-IT2} + S_{CB-IT3}$.

Balancing Authority	Sink Balancing Authority for:	Source Balancing Authority for:	Sending Balancing Authority for:	Receiving Balancing Authority for:	Net Interchange Schedules
A	IT3	IT1, IT2	IT1, IT2	IT3	$S_{AB-IT1} + S_{AB-IT2} + S_{BA-IT3}$
B	IT1		IT2, IT3	IT1, IT2, IT3	$S_{AB-IT1} + S_{AB-IT2} + S_{BA-IT3}$ $S_{BC-IT2} + S_{CB-IT3}$
C		IT3	IT2, IT3	IT2	$S_{BC-IT2} + S_{CB-IT3}$ S_{CD-IT2}
D	IT2			IT2	S_{CD-IT2}

Table 1 - Relationship Between Balancing Authorities, Interchange Schedules, and Interchange Transactions

Implementing Interchange

Interchange Transactions are the representation of a *PSE* or *BA* arranging for energy and capacity transfers between different parties. From a real-world perspective, these compiled arrangements are known as a *Request for Interchange (RFI)*. The *RFI* goes through two types of assessment: *Market Assessment* and *Reliability Assessment*.

Prior to the assessment stages, the *PSE* puts together the business arrangements for the *Interchange* with *Transmission Service Providers (TSPs)*, *Generation Providing Entities (GPEs)*, and *Load-Serving Entities (LSEs)* and may obtain preliminary reliability approvals from *BAs*, *TSPs*, and *Reliability Coordinators (RCs)* where required. At this stage, *Agreements* (including *Transmission Service* reservations) are aggregated into a single request. This aggregated information, the *RFI*, is sent to the *BAs*, *PSEs*, and *TSPs* and begins both the *Market Assessment* and *Reliability Assessment*.

During the *Market Assessment* and *Reliability Assessment*, the *RFI* proposed by the *PSE* is evaluated by the approval entities to ensure all the proper information has been given for both commercial and reliability issues and that system conditions allow for approval. Note that the actual *RFI* submission can be assessed and approved or denied by both market and reliability entities.

In both the NERC Standards and NAESB Business Practice Standards, *RFIs* go through several transitions as they are evaluated. Prior to either assessment period, any compiled arrangements are known only as *RFI*. Once the *RFI* is passed to the reliability and market entities to begin evaluation during the *Reliability Assessment* and *Market Assessment*, respectively, then the *RFI* becomes known as *Arranged Interchange*. If approvals are obtained from all entities with approval rights during the *Reliability Assessment* and *Market Assessment*, then the *Arranged Interchange* transitions to *Confirmed Interchange*. *Confirmed Interchange* has obtained all necessary approvals and is ready to be implemented in the *Net Scheduled Interchange* portion of all impacted *BAs*. Once the *Ramp* start time is reached, *Confirmed Interchange* transitions to *Implemented Interchange*. At that point in time, each impacted *BA* will implement the *Implemented Interchange* value into their *Area Control Error (ACE)* equation as part of the *Net Scheduled Interchange*.

The “Normal” Process of Coordinating Interchange

Figure B below shows the normal, reliability-related steps in coordinating *Interchange*. When the *RFI* is submitted to the *Sink Balancing Authority*, it is processed through the *Market Assessment* and *Reliability Assessment*. Once approved during the assessments, the *Sink Balancing Authority* electronically distributes the *Interchange* status, and the *Interchange* information is entered into the *Wide Area Reliability Tool* and into the *ACE* equations of the applicable *BAs*. Note that the NERC INT Standards require coordination of any *Interchange* with any DC tie operating *BA* on the *Scheduling Path*.

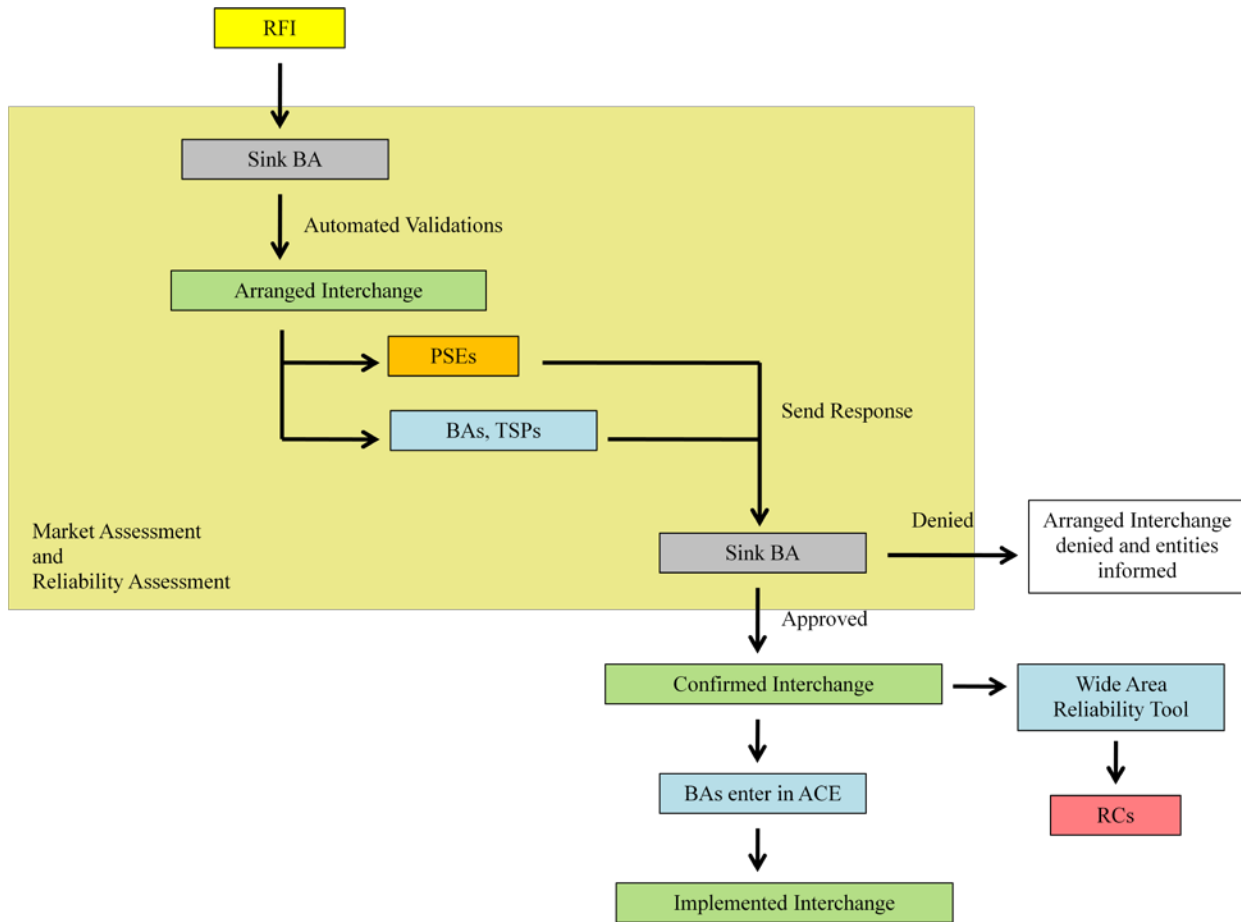


Figure B - Processing on Initial RFI Submission

Interchange Changes for Reliability Reasons

Once *Arranged Interchange* has transitioned to the *Confirmed Interchange* or *Implemented Interchange*, it is entirely possible that the *Interchange* parameters (i.e., MW, Ramp start and stop, duration, etc.) may need to change for reliability reasons. The change to *Confirmed Interchange* or *Implemented Interchange* does not eliminate the necessity for coordination. While Figure B shows the coordination that takes place when an *RFI* is initially submitted, Figure C shows coordination steps to effect a change to *Confirmed Interchange* or *Implemented Interchange*.

Interchange created to address an actual or anticipated reliability-related risk or as part of an energy sharing *Agreement* is implemented first without submitting an *RFI* and then follows the submission and transition steps shown in Figure B. *Interchange modified* to address an actual or anticipated reliability-related risk, known as *Reliability Adjustment RFI*, is implemented first and then follows the submission and transition steps shown in Figure C. Note that when submitting *Reliability Adjustment RFI*, only a *Reliability Assessment* occurs since approval rights are only granted to the *Source Balancing Authority* and *Sink Balancing Authority*.

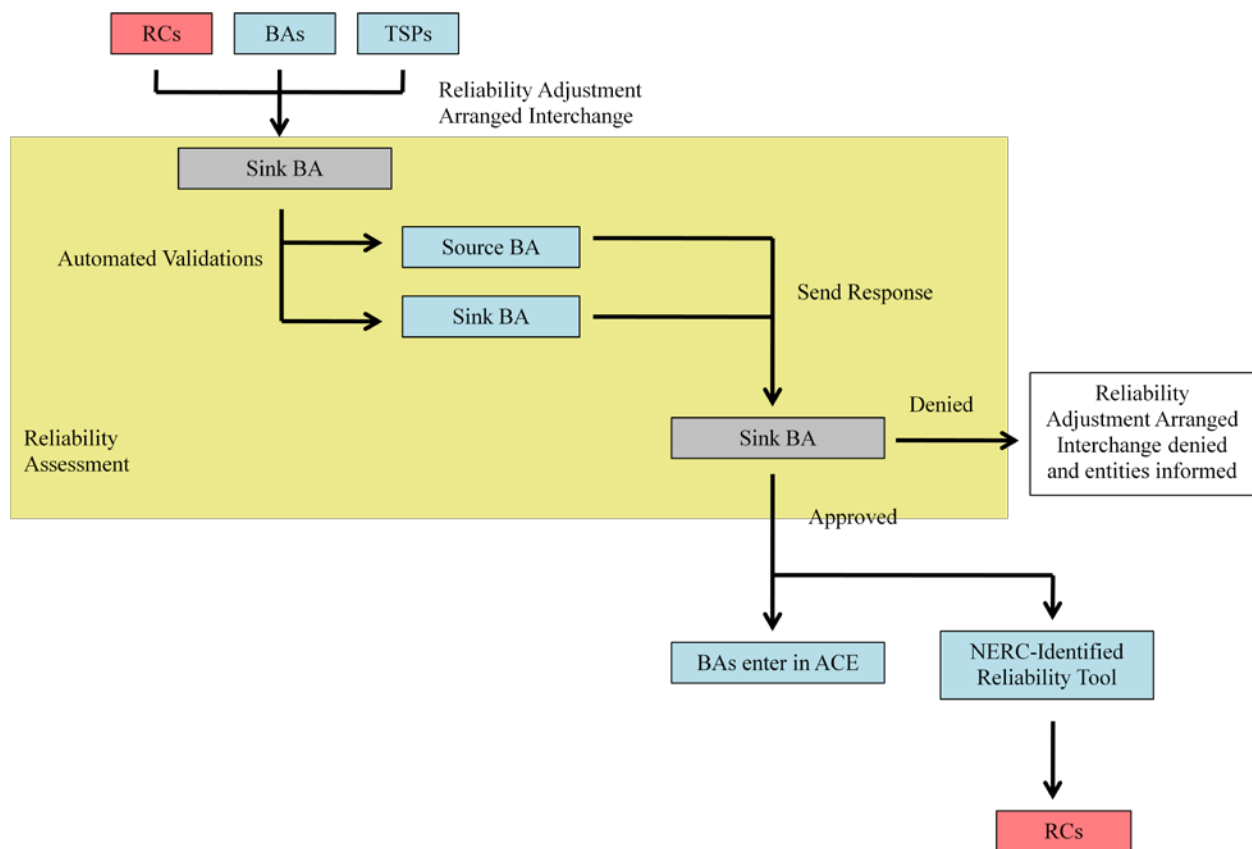


Figure C – Processing of Reliability Adjustment RFI Request

Interchange Changes for Market Reasons

Figure D shows a change (e.g., cancel, increase MW, decrease MW, change *Ramp* or duration info, etc.) initiated by the *PSE*, *BA*, or *Market Operator* for non-reliability reasons once the *Arranged Interchange* has transitioned to *Confirmed Interchange* or *Implemented Interchange*. In this case, the *Confirmed Interchange* or *Implemented Interchange* will undergo the same *Market Assessment* and *Reliability Assessment* as performed when submitting the initial *RFI*. Subsequent steps also follow the same process.

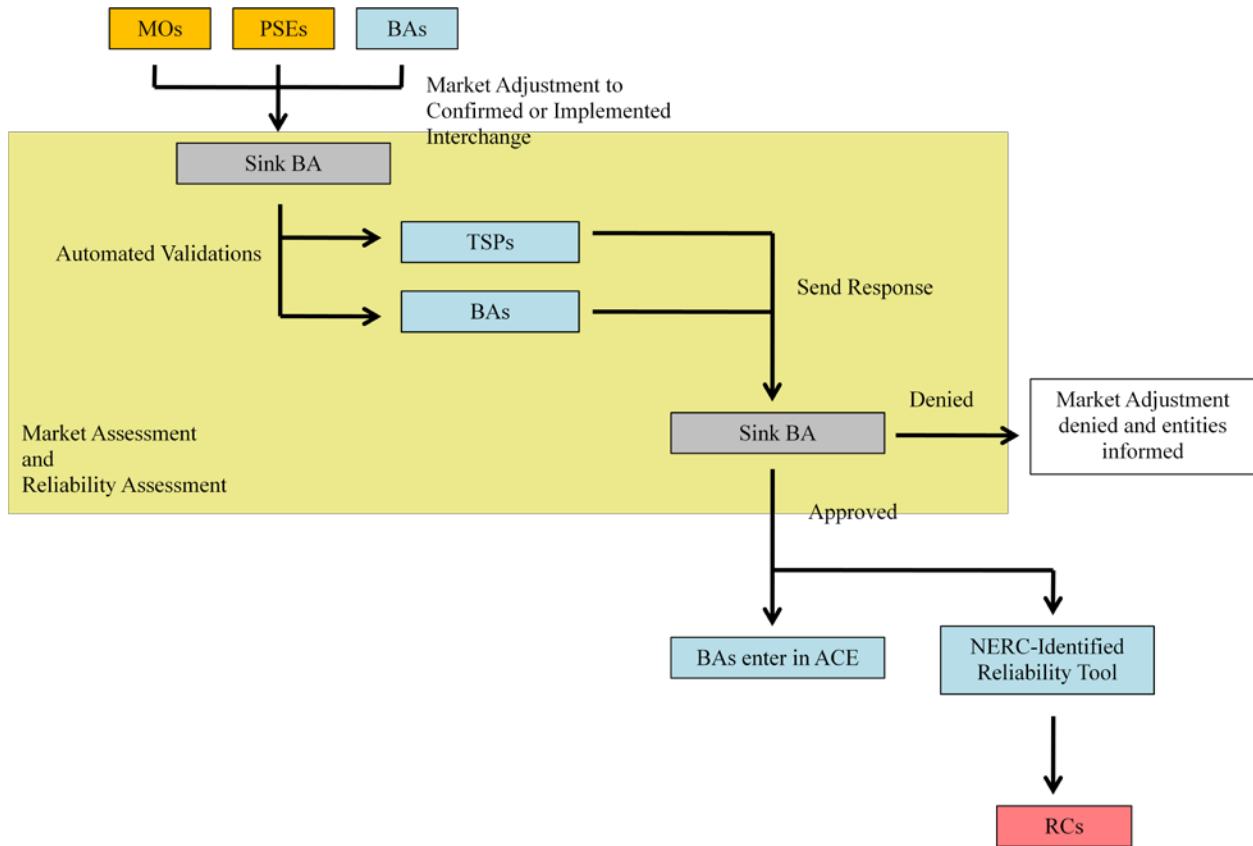


Figure D – Processing of Market Adjustment Request

Practical Guide to Interchange Implementation

The previous sections of this document detail some of the concept behind accomplishing *Interchange*. The first section discussed *Interchange* in terms of how it is transferred between different entities. The second section discussed the way *Interchange* is processed from a theoretical perspective and using terms that are not used during the daily processing of *Interchange*. This section will describe how *Interchange* is practically accomplished on a daily basis.

Interchange is a coordinated process. This process involves arranging for transferring power from a source to a sink point and arranging for the *Transmission* rights across all impacted entities. As this practice grew in volume, the industry moved to adopt technology that would facilitate the business and allow *RCs* to manage *Transmission* congestion. The systems that facilitate the business are based on the e-Tag specifications and schema. Systems implementing the e-Tag specifications allow for entities involved in *Interchange* to assemble an *RFI* into an e-Tag and then send it out for the required approvals before implementation. Any entity that has registered a Tag Agent Service in the EIR can assemble and submit an e-Tag. Typically an entity related to the *Sink Balancing Authority* is responsible for gathering the power deals and *Transmission* rights for submission.

The e-Tag Specifications and Schema are maintained by NAESB and assist in providing the processes required by the NERC and NAESB standards related to *Interchange*. The Joint Electric Scheduling Subcommittee has the primary obligation of monitoring and modifying the e-Tag Specifications and Schema and also has reporting obligations to both the NAESB Executive Committee and the NERC Interchange Subcommittee.

A Note on Wide Area Reliability Tools

In order to maintain reliability, *Interchange* must be coordinated with several entities other than those involved in the transaction. One type of monitoring is accomplished by *Wide Area Reliability Tools*; examples of such tools include the IDC in the Eastern *Interconnection* and webSAS in the Western *Interconnection*. These tools are used for managing congestion when *RCs* (Eastern *Interconnection*) or *BAs* (Western *Interconnection*) issue adjustments to *Interchange* to relieve congested paths in real-time. Each *Wide Area Reliability Tool* has a specific set of rules on how *Interchange* is adjusted.

Functions Detailed in the e-Tag Specifications

The e-Tag Specifications and Schema discuss the practices and technical details needed in the systems that drive e-Tag. Systems implementing the e-Tag specifications are based on transferring data over the Internet to gather and distribute approvals. Most entities implement the e-Tag specifications by contracting with vendors that have developed these systems. The e-Tag Specifications details three main functions that are needed, and all three functions are accomplished by most vendors with their software:

1. Tag Agent - Software component used to generate and submit new e-Tags, Corrections, and Profile Changes to an Authority and to receive State information for these requests.

2. Tag Approval - Software component used to indicate individual approval entity responses when requested by Authority Service as well as submit Profile Changes.
3. Tag Authority - Software component that receives Agent and Approval Requests and Responses and forwards them to the appropriate Approval Services. Also maintains master copy of an e-Tag (all associated Requests), the Composite State of the e-Tag, etc. and responds to queries regarding the e-Tags in its possession.

These different functions ensure that e-Tag submission, approval, and coordination are all handled properly.

Parts of an e-Tag

An e-Tag has several required components in order to be valid. Without these components, the necessary information would not be conveyed to the approving entities. Most software has checks in place to ensure the proper information is supplied. The required parts of an e-Tag include:

1. e-Tag ID – Each e-Tag has a unique e-Tag identifier based on four key attributes:
 - a. Source Balancing Authority Code
 - b. PSE Code (Tag Author PSE)
 - c. Unique transaction identifier
 - d. Sink Balancing Authority Code

The codes specified above for *BAs* and *PSEs* come from the EIR which will be detailed below.

2. Transaction Types – There are several variations in the transaction type that can be chosen for an e-Tag. Transaction types assist in noting the purpose and implementation of a particular e-Tag. Specific *Transmission* tariffs and *Business Practices* should be referenced to determine which of the following transaction types should be selected. e-Tag recognizes the following transaction types:
 - a. Normal: These are the normal energy *Schedules* and should represent the largest number of e-Tags. They will include *Schedules* that use *Point to Point Transmission Service*, *Network Integration Transmission Service*, or grand-fathered service under a regional tariff.
 - b. Dynamic: A *Dynamic Schedule* is scheduled using an expected value but the actual energy transfer is determined in *Real-time* by separate communications external to the e-Tag system. Also included in this type will be regulation energy *Schedules* and energy imbalance *Schedules*. The e-Tag should contain the expected average energy in the energy profile and contain the maximum expected energy in the Transmission Allocation. Dynamic e-Tags may be adjusted by the *Source Balancing Authority*, *Sink Balancing Authority*, or e-Tag author up to 168 hours in the past using a market adjust to set the actual *Interchange Schedule* value. For additional information related to implementation of *Dynamic Schedules*, please see the Dynamic Transfer Reference Guidelines.

- c. Emergency: *Emergency Schedules*, including reserve sharing, *Spinning Reserve*, and supplemental reserve may be scheduled as *Emergency Schedule* Type. For additional detail of when to use Emergency type, see the NERC Glossary of Terms for *Emergency RFI* as well as *Emergency* and *Energy Emergency*.
 - d. Loss Supply: Loss Supply type is used for customers to self-supply losses. This type is used to differentiate between a loss *Schedule* and a normal *Schedule*. Some tariffs presently require that *Schedules* for losses require different treatment than *Schedules* for the associated energy.
 - e. Capacity: Capacity type is typically used for entities to import *Operating Reserves* from outside their *Reserve Sharing Group* but may also be used to arrange for purchases or sales of *Spinning Reserve* and supplemental reserve between other entities. This type of e-Tag may be activated upon contingency with zero *Ramp* durations.
 - f. Pseudo-Tie: A *Dynamic Transfer* implemented as a *Pseudo-Tie* rather than a *Dynamic Schedule*. This type is used in the same way as a Dynamic e-Tag. These e-Tags may be adjusted in the same manner as Dynamic transaction type e-Tags. For additional information related to implementation of *Pseudo Ties*, please see the Dynamic Transfer Reference Guidelines.
 - g. Recallable: A WECC-only transaction type typically used for “interruptible” or “non-firm” transactions. Adjustments to this transaction type only require *Source Balancing Authority & Sink Balancing Authority* approval..
3. Market Segments – Each e-Tag has a section to identify those portions of the path that are associated with the tracking of title and responsibility. Market Segments contain information that describes the market information, such as the identity of the market participant, the firmness of energy the market participant is delivering, and the physical segments the entity is responsible for providing. Market Segments must be listed in order from the *PSE* responsible for generation to the *PSE* responsible for *Load*. There will only be one market segment for generation and one segment for *Load*, but there can be multiple intermediate market segments. Market Segments can describe the responsibility for scheduling actual power delivery, or it can describe non-physical title transfers. These are seen when a market participant takes financial possession for the energy commodity but does not physically move that energy before transferring possession to another financially responsible party. When this occurs, the market segment will not contain any physical segments.
4. Physical Segments – e-Tags also have a section to represent those portions of the path that are physical in nature and represent a movement of energy. There are three types of Physical Segment:
- a. Generation - Generation Segments contain information that describes a generation resource, such as the location of the generation, the firmness of the energy supplied by the resource, and contract references that identify the resource commitment.

- b. Transmission – Transmission Segments contain identification that describes a *Transmission Service*, such as the identity of the provider, the *Point of Receipt (POR)* and *Point of Delivery (POD)* of the service, the firmness of the service, simple loss information, and contract references that identify the service commitment. Load - Load Segments contain information that describes a *Load*, such as the location of the *Load*, the interruptability of the *Load*, and contract references that identify the *Load* obligation. All definitions for information in the segments above must be valid in the EIR which will be described below. Physical Segments must be listed in order from Generation to *Load*. Generation Segments must always be listed first, while Load Segments must be listed last. e-Tags may only have one Generation Segment and one Load Segment. All physical segments must reference a parent market segment, identifying the market entity responsible for the physical segment. These references must also be in an order that matches that described by the market segments. An optional field in the Physical Segments is Scheduling Entities. Many TSPs require that e-Tags illustrate not only the contractual relationship between the TSP and the *Transmission Customer* but also the internal scheduling information to implement the *Transmission Service* sold under their TSP's *Transmission* tariff. To this end, Scheduling Entities may be defined for a particular Transmission segment.
5. Profile Set – The Profile Sets, commonly referred to as the Energy Profile, section of an e-Tag defines the level at which transactions should run as well as the factors that set those levels. Profiles are specified as a series of time-ordered segments of duration associated with a particular profile. Profiles may optionally contain *Ramp* duration (in minutes) associated with both start time and stop time. The *Ramp* stop time is not needed (and is ignored) in any profile except for the last profile. The *Ramp* duration specifies the number of minutes over which the generator will change from the previous block level to the current block level. *Interchange Schedule* ramping is executed between BAs using straddle *Ramp* methods as defined below in “Other Interchange Schedule Concepts”.. The *Ramp* duration exists in the e-Tag in order to provide a vehicle by which *Ramp* duration may be exchanged between entities. The Profile Set of an e-Tag is influenced by two different profiles:
- a. Market Limit - The Market Limit defines the level at which the e-Tag author wishes the transaction to run. This level can be used to specify an initial value for a *Dynamic Schedule* as well as a simple level at which the transaction is to be run.
- b. Reliability Limit – The Reliability Limit defines the maximum allowable level at which a transaction may run when that transaction has been identified by a RC or other reliability entity as being limited by some *Constrained Facility*. This limit is typically used to indicate *Curtailments*.

The lower of the most recent approved Market Limit and most recent approved Reliability Limit sets the Current Level on an e-Tag. The Current Level contains the level at which the transaction should be running based on all approved Requests processed by the Authority.

6. Transmission Allocation - Transmission Allocations are a type of e-Tag profile set that defines the way in which market participants will fill their capacity commitments with *Transmission Service* reservations. Transmission Allocations specify a particular reservation, the provider associated with the reservation, and profiles associated with that reservation that describe how the reservation should be consumed. Transmission Allocations must always be associated with Transmission Physical Segments; association with other segments (such as Generation or Load) is not allowed. The Maximum Reservation Capacity associated with each physical segment should be greater than or equal to the energy profile. The Transmission Allocation for all Transmission segments must be greater than or equal to the minimum of the *POR* profile and *POD* profile for that segment. One or more *Transmission Service* reservations may be utilized together in what is known as stacking. There are two types of stacking:

a. Vertical Stacking – A market participant may have two or more *Transmission Service* reservations flowing from the same source to the same sink for the same time period. In this case, Vertical Stacking can be used to tag a Profile Set equal to the combined capacity of the two *Transmission Service* reservations. For example, an e-Tag author can use two 50 MW *Transmission Service* reservations on the same e-Tag to cover 100 MW on the Energy Profile. Figure E shows an example of how Vertical Stacking appears on an e-Tag.

Start Time	Stop Time	Energy Profile MW	Transmission Allocation	
			Reservation 1	Reservation 2
12:00	13:00	100	50	50

Figure E – Vertical Stacking

b. Horizontal Stacking – A market participant may have two or more reservations flowing from the same source to the same sink for different hours. In this case, Horizontal Stacking can be used to tag a Profile Set for the entire time range as long as the capacity of the *Transmission Service reservation* for each hour is not exceeded. For example, an e-Tag author can use two 100 MW *Transmission Service* reservations in subsequent hours to cover 100 MW on the Energy Profile for both hours. Figure F shows an example of how Horizontal Stacking appears on an e-Tag.

Start Time	Stop Time	Energy Profile MW	Transmission Allocation	
			Reservation 1	Reservation 2
12:00	13:00	100	100	
13:00	14:00	100		100

Figure F – Horizontal Stacking

7. Loss Accounting – The Loss Accounting section of an e-Tag specifies the manner in which losses should be accounted for over a specified period of time. Over time, an e-Tag Author may elect to specify different choices for how losses will be provided. Usually each *Transmission Operator* across which an e-Tag flows will have specified transactions which require losses and also usually detail what type of losses are required. The two main types of losses in the industry today are Financial Losses and In-Kind Losses. The type of losses provided is dependent upon each Transmission Provider’s tariff / contract.

A Note on the Electric Industry Registry

Several sections detailing the required parts of an e-Tag make reference to the EIR. The EIR is a database where participants in the e-Tagging process register information involved in the process. This registration includes entity names and codes, such as *PSEs*, *BAs*, and *TSPs*. Other pieces of information that are registered include Source and Sink names used on e-Tags, authorized *PSEs* for specific sources and sinks, and valid products for use on e-Tags. The EIR is managed by NAESB.

E-Tag Approval and Timing Process

Once an e-Tag is submitted by an author, it is distributed by the Tag Authority to the appropriate approval entities. For new e-Tag submissions and modifications to e-Tags made by *PSEs*, the *PSEs*, *BAs*, *TSPs* specified on the e-Tag have approval rights. For e-Tag modifications requested for reliability reasons (*Curtailments* and reloads), only the *Source Balancing Authority* and *Sink Balancing Authority* have approval rights. All reliability entities must provide their approval for an e-Tag or modification to an e-Tag to be implemented.

In order to manage this approval process, the industry has developed guidelines around the timing of submitting and processing the approvals. These timing rules are part of the NERC Interchange Standards as well as the NAESB Wholesale Electric Quadrant Business Practice Standards. There are differences in the timing tables between the Eastern *Interconnection* and ERCOT *Interconnection* versus the Western *Interconnection*. Therefore, two different tables are used to show these timing differences.

Any e-Tag that is submitted or modified “On-Time” as defined in the NERC INT standards timing tables, as well as any modification to an e-Tag submitted for reliability reasons, must be evaluated. All Late or *After the Fact (ATF)* e-Tag submissions should be evaluated as time permits.

Other Interchange Schedule Concepts

1. **Ramp duration.** When the *Sending Balancing Authority* and *Receiving Balancing Authority* implement an e-Tag between each other in their respective *ACE* equations, the *BAs* must begin their generation adjustments at the same time using the same *Ramp* durations. A mismatch of these parameters will cause a *Frequency Error* in the *Interconnection*. The standard *Ramp* for e-Tags in the Eastern and ERCOT *Interconnections* is 10 minutes across the e-Tag start time (straddle), and the standard *Ramp* for e-Tags in the Western *Interconnection* is 20 minutes across the tag start time (straddle). Non-standard *Ramps* may be used as long as all *BAs* involved in the *Transaction* agree to the *Ramp* stated on the e-Tag. Figure G shows standard *Ramps*.

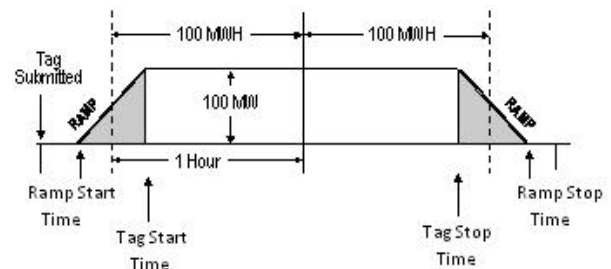


Figure G - Interchange Schedule resulting from 100 MW Interchange Transaction for two hours showing ramps, energy profiles, and energy accounting for each hour.

2. **Starting and ending times.** Most e-Tags generally start and end on the *Clock Hour*. However, *PSEs* may submit e-Tags that start and/or stop at other times beside the *Clock Hour*. *BAs* and *TSPs* should try to accommodate these intra-hour e-Tags. Figure G shows a two hour *Interchange Schedule* starting and stopping at the top of the hour.

3. **Interchange accounting.** All *BAs* must account for their *Interchange Schedules* the same way to enable them to confirm their *Net Interchange Schedules* each day with their *Adjacent Balancing Authorities* as required in NERC BAL Standard **BAL-006 (Inadvertent Interchange)**. *BAs* traditionally use “block” *Interchange Schedule* accounting. This accounting method ignores straddle *Ramp* times and instead uses the *Transaction* start and stop times. This, in effect, moves the energy associated with the starting and ending *Ramps* into their adjacent starting and ending *Clock Hours* of the *Interchange Schedule*. Figure H illustrates the block accounting principle.

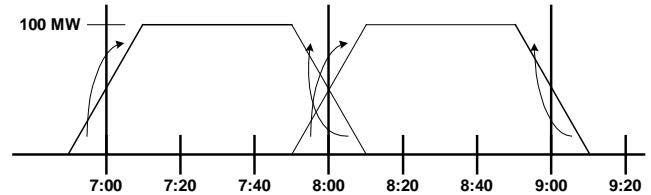


Figure H - Block accounting moves the ramp energy into the adjacent Clock Hours.

A Note on Dynamic Transfers

Dynamic Schedules and *Pseudo-Ties* are special *Transactions* that rely on time-varying energy transfers. While *e-Tag* provides for both transaction types, many tagging requirements for both types are addressed in regional criteria and *Transmission Operator Business Practices*. For more detail on these types of *Transactions*, see the NERC Dynamic Transfer Guidelines document.

Consideration for Interchange Involving DC Tie Operators

Per the NERC INT Standards, the *Sending Balancing Authorities* and *Receiving Balancing Authorities* will coordinate *Interchange with any DC tie operating BA*. Note that DC tie operators that are *Intermediate Balancing Authorities* would receive the *Interchange Schedule* information and be subject to the applicable INT standards. The DC Tie operator also would be responsible for notifying the *Sink Balancing Authority* of a DC tie trip and the associated Interchange modification



**New Section VII
approved by Operating
Committee**

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NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5731

Electric System Restoration Reference Document

by the

North American Electric Reliability Council

April 1993

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Foreword

On November 9, 1965, a cascading failure of the electrical system left 30 million people in the dark and caused economic losses estimated at over \$100,000,000. Major portions of the northeastern United States and Canada were without electricity. Hundreds of thousands of people were inconvenienced for days. The Federal Power Commission investigated the blackout and recommended ways to ensure that it would not likely happen again. Instead of a mandatory federal program to coordinate electric power, electric utility representatives from 12 regional and area organizations signed an agreement creating the North American Electric Reliability Council (NERC) on June 1, 1968.

The NERC organizational structure provides the mechanism by which electric utilities work together to prevent blackouts. A strength of this structure lies in NERC's ability to call on unmatched expertise and experience from member utilities to serve on its various committees. These people work together to critique the past, monitor the present, and assess the future. NERC establishes and updates Criteria and Guides for reliably operating the bulk electric system. Reliability is NERC's sole mission, and these criteria are based on coordination, cooperation, communication, and commitment.

The NERC and Regional Criteria and Guides present characteristics of a well-planned and operated electric network and describe adequacy and security tests necessary to evaluate its performance. The interconnected electric network is designed and operated such that uncontrolled, widespread interruptions are unlikely. However, building and operating an electric system, which provides 100% reliability is impossible.

I. Introduction

This document provides general guidelines to be followed in the event of a partial or complete collapse of any of the interconnected electric systems in the North American continent. Quick implementation of each control area's restoration plan, compiled in accordance with the suggestions and recommendations contained in this document, will facilitate coordination between member control areas and ensure the earliest possible restoration of the electric system.

It is impossible to predict all the possible combinations of problems, which may occur after a major electric system failure. It is, therefore, the responsibility of system operators to restore the electric system BY applying the general guidelines outlined in this document and in their respective detailed system restoration plans. Mutual assistance between member control areas is highly encouraged.

A. Principles

Each control area should have a readily accessible and sufficiently detailed current system restoration plan to guide in an orderly recovery. System restoration will be aided by communicating to neighboring control areas, and to Regional offices, an accurate assessment of system conditions throughout the restoration process. Communication must be established with power plants, critical substations, and neighboring operation centers. Mutual assistance and cooperation are essential and beneficial to prompt system restoration and to avoid the recurrence of a partial or complete electric system collapse.

In the event of an electric system collapse, each control area should use the following as guiding principles for the restoration process:

1. Take immediate steps to initiate internal system restoration plans.
2. Restore a high percentage of internal load in as little time as possible.
3. Provide assistance to any and all control areas as system conditions allow.
4. Supply neighboring control areas and Regional offices with information on electric system status.
5. Coordinate with neighbors the reconnection of control areas and/or islands.

B. Plan Elements

Actions required for system restoration include identifying resources that will likely be needed during restoration, determining their relationship with each other, and training personnel in their proper application. Actual testing of the use of the strategies is seldom practical. Simulation testing of plan elements, major plan sections, or the overall plan are essential preparations toward readiness for implementation on short notice.

Control area restoration plans include the following elements:

1. Philosophies and strategies for control area restoration
2. Selection of critical alarms from the alarm information available
3. Identification of the relationships and responsibilities of the personnel necessary to the restoration
4. Identification of blackstart resources including:
 - a. generating unit resources
 - b. sufficient fuel resources
 - c. transmission resources
 - d. communication resources and power supplies
 - e. mutual assistance arrangements

5. Contingency plans for failed resources
6. Identification of critical load requirements
7. Provisions for training of personnel
8. Provisions for simulating and, where practical, actual testing and verification of the resources and procedures
9. General instructions and guidelines for:
 - a. system operators
 - b. plant operators
 - c. communications personnel
 - d. transmission and distribution personnel
10. Provisions for public information

The body of this document contains more details on items to be considered in the restoration process, which may be used in the development or review of individual control area system restoration plans.

C. *Priorities*

Establishing priorities can be subjective and even change from one incident to another or one area to another. Starting units with blackstart capability and providing auxiliary power to units that have just been shut down is clearly a very high priority.

The following actions for system restoration should be considered by each control area and assigned proper sequence and priority:

1. Stabilization of generating units
2. Restoration and maintenance of intra- and inter-system communication facilities and networks
3. Assessment of control area condition and bulk electric system conditions
4. Contact local police and fire departments concerning the extent of the problem
5. Contact with public information agencies to request the broadcasting of pre-distributed appeals and instructions
6. Restoration of units with blackstart capability
7. Providing service to critical electric system facilities
8. Restoration of the control area's transmission system
9. Connection of islands taking care to avoid recurrence of a partial or complete system collapse and equipment damage
10. Restoration of service to critical customer loads
11. Restoration of service to remaining customers

If it becomes apparent that the emergency is a Regional one, the focus of restoration action should shift from individual control area priorities to bulk electric network priorities. Giving priority to a neighboring system's generation and/or load may be necessary in order to benefit the rapid restoration of the bulk electric system. As generation and transmission facilities become available, systematic restoration of network load should proceed using established priorities.

D. *Responsibilities*

Each control area should train associated personnel (system operators, power plant operators, etc.) in the implementation of its detailed internal system restoration plan. Non-control area electric utilities should prepare a plan, in cooperation with their responsible control area, designed to assist and coordinate with the control area's plan. This applies to cogeneration facilities and independent power producers. Where appropriate, a copy of these plans should be on file at the

Regional offices. System restoration plans should be verified by as much simulation testing as possible, although actual physical testing is highly encouraged where feasible. Simulation also can help determine the feasibility of parallel activities, sequential activities, and avoidance of unnecessary loss of equipment life. Control areas should report significant testing activities of system restoration plans to their Regional Reliability organization and summarized Regional activity should be presented to the NERC Operating Committee.

II. Conditions That May Result in Major Area Blackouts

A. Definitions

A blackout is a condition where a major portion or all of an electrical network is de-energized with much of the system tied together through closed breakers. Any area whose tie lines to the high voltage grid cannot support reasonable contingencies is a candidate for a blackout. The area will become electrically isolated if a *critical contingency* should occur. The identification of these areas, as indicated in Figure 1, should be a high priority for minimizing blackouts.

Separation of an island from the grid will take place under two general scenarios:

1. Dynamic instability
2. Steady-state overloads and/or voltage collapse

System separations are possible at all loading levels and all times in the year. Changing generation patterns, scheduled transmission outages, off-peak loadings resulting from operations of pumped storage units, storms, and rapid weather changes among other reasons can all lead to blackouts. Systems must always be alert to changing parameters that have the potential for blackouts.

B. Separation Due to Dynamic Instability

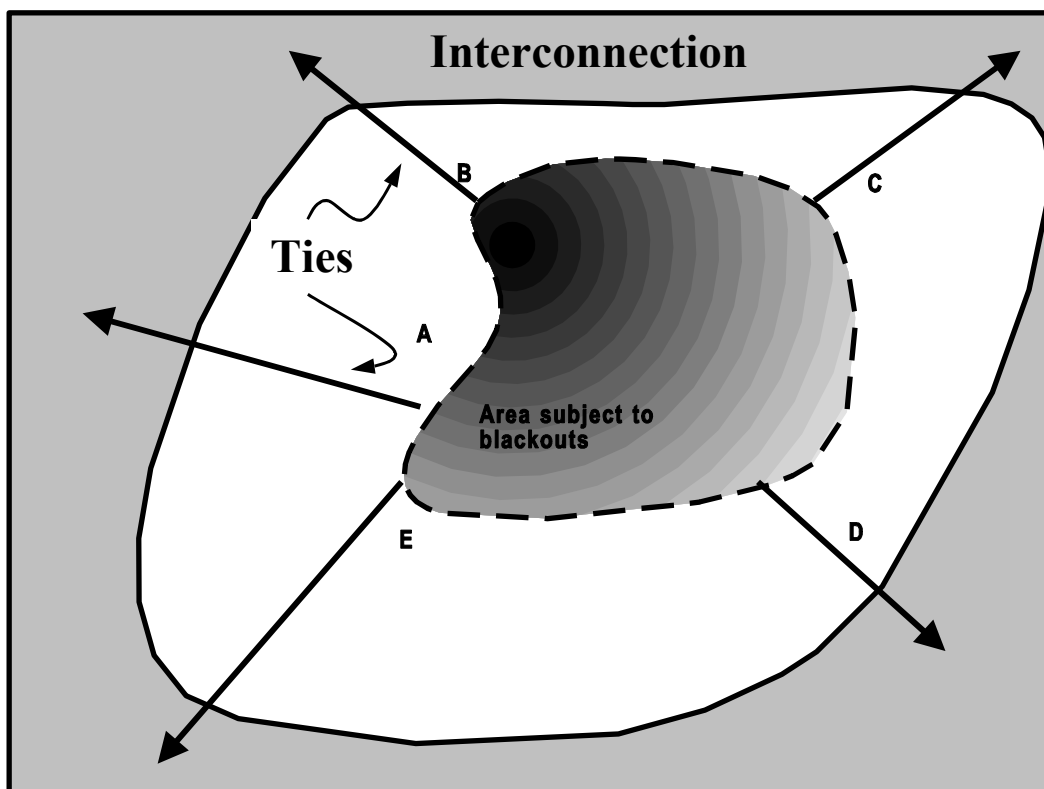
The transmission system should be able to sustain any single contingency without loss of load. If the steady-state response to a single contingency does not drive loadings beyond facility capabilities, it should be expected that the dynamic response to the single contingency will be stable. The damping of the system should be adequate. Except in very special cases, the steady-state response will be more constraining than the dynamic response to a single contingency. For this reason, separations due to dynamic instability are typically initiated by multiple contingencies such as loss of corridors, several transmission circuits, several generating units, or delayed fault clearing. These contingencies were referred to before as a *critical contingency*.

Following the *critical contingency*, a tie line of Figure 1 will approach an out-of-step condition. Cascading of the other ties will isolate the area from the grid. There will be no time for operator intervention. If possible, isolated areas should be automatically established with good generation to load ratios. Early detection of unstable conditions may be possible in some parts of the system.

In these cases, selective use of transfer trip relaying can isolate an area with a favorable generation to load ratio. In general, there may be no clearly defined area that will separate. In such cases, the extent of the affected area will only be known after-the-fact.

If the isolated area is generation deficient, underfrequency relays should shed the necessary load to match load and generation in the island, and the operation should become stable at or near 60 Hz. If not, load should be shed to restore stable operation near 60 Hz. If the isolated area has excess generation, the total area generation must be reduced immediately to approximate the area load for 60 Hz operation. When possible, schemes for islanding as well as frequency correction programs should limit the consequences of stability contingencies. Controlled islanding action is preferred to blackouts.

Figure 1 – Area isolated from the Interconnection



C. Collapse Due to Steady-State Overloads and/or Voltage Collapse

The system just prior to a blackout may not be dynamically unstable but in an overloaded condition. At such loadings, the collapse may come about due to damage to thermally overloaded facilities, or circuits contacting underlying facilities or vegetation. When an overloaded facility trips, other facilities will increase their loadings and may approach their thermal capabilities or relay trip settings. There may be some time to readjust system conditions (generation shifts, load shedding, transfers, etc.). If not, the overload will lead to electrical isolation.

Voltage collapse, as currently defined by the IEEE Working Group on Voltage Stability, is the process by which voltage instability leads to the loss of voltage in a significant part of the system. This condition results from reactive losses significantly exceeding the reactive resources available to supply them. Circuits loaded above surge impedance loadings and reduced output of shunt capacitors as voltages decline can lead to accelerating voltage drops. It is possible that impending voltage collapse can be detected by slowly dropping voltages in an area of concern. However, heavy use of shunt capacitors or reactors can maintain near normal voltage up to the point that voltage support resources run out. Thus, voltage collapse can look like both a steady-state problem with time to react and a problem where no effective operator intervention is possible. The NERC *Survey of the Voltage Collapse Phenomenon* provides more insight into this problem.

It is very hard to predict the area that will be affected or electrically isolated from the grid. Adequate models of load variation with voltage are not available, and there is an undeterminable variety of sequential circuit operations that can lead to wide area collapses.

The characteristics of a steady-state voltage collapse are different from those of a separation due to dynamic instability:

1. The *critical contingency* may be a single contingency if a heavily loaded circuit exceeds its capability or gets close enough to material objects to flash over.
2. The process of voltage collapse is usually slow enough to permit operator intervention to reverse the process if adequate information and resources are available.

The prevention of the voltage collapse is usually accomplished by shedding load or by rapid generator response to quickly relieve the overloads. These remedial actions do not form an electrical island as may be attempted for dynamic stability problems.

D. Blackout Causes

Blackouts originate from power system disturbances resulting in loss of service to all loads within an area. System disturbances are reported when they turn into large service interruptions.

The DOE criteria for reporting major bulk power system disturbances for systems with peak load greater than 3,000 MW is:

1. Loss of 300 MW load for greater than 15 minutes
2. Loss of service to over 50,000 customers for more than three hours

In addition, CIGRE Study Committee 39, Group 05 AOperational Performance of Power Systems[≅] has performed a worldwide survey on power system disturbances. The severity of the disturbances was measured in terms of System Minutes:

Degree 1 X From 1 to 9 System Minutes
Degree 2 X From 10 to 99 System Minutes
Degree 3 X From 100 to 999 System Minutes
(One System Minute is equivalent to an interruption of the total load of a system for one minute.)

The CIGRE study committee only reported the main cause of disturbances. For instance, a system disturbance resulting from a circuit fault and a subsequent failure of a breaker to clear would be reported as caused by breaker failure if the system should have been able to withstand the original fault. The main causes are listed as follows:

Faulty conventional protection and control equipment
Faulty special protection (i.e., generation rejection scheme)
Lightning
Weather other than lightning
Solar magnetic disturbances
Faulty high-voltage equipment
Personnel error
Other causes
Unknown

There were 295 disturbances reported for the period 1982 to 1989. Of these, there were 271 disturbances with an identified main cause. Over 22% of the disturbances were caused by lightning, other weather and solar magnetic disturbances, over 47% were caused by faulty equipment, and 7% were the result of personnel errors.

Since power system disturbances appear to occur at random, remedial schemes should be considered when possible and appropriate. These schemes will detect the disturbance early enough to avoid the total outage of an area.

III. Determine Blackout Extent and System Status

A. Communication

A functional communication system is critical for the assessment of the extent of a blackout and determining the status of generation and transmission facilities. Utilities should review their communication systems, regardless of whether it is a private carrier (telephone company) or electric utility owned. The assessment is essentially the same for a private carrier or electric utility owned. It should be determined that there is an adequate power source to the communication equipment in order to handle the duration of the blackout conditions. Battery capacity, standby generation availability, enough fuel, or adequate refueling plans also need to be studied. For utilities sharing communications equipment and networks with their neighboring utilities, both users should assess the impact of equipment failure.

B. Customer Calls

In the early stages of system restoration, utility dispatch centers will be bombarded with phone calls from employees and customers. From the utilities perspective, continual calls inquiring into the status of service serves no useful purpose. In fact, continual customer calls may be a detriment by degrading the public telephone system to a point that it is not functional for the utility. Some of the ways of mitigating problems are:

1. Automatic dialing system to notify employees of the status
2. Immediate notification of customer service representatives
3. Public appeal to limit phone system use
4. Priority call system for utility dispatchers' phone systems

Dispatch centers that do not handle customer calls should consider establishing a center or desk for communicating with governmental and public agencies. Dispatchers will then be able to focus directly on operations.

C. RTU Operation Without AC Power

In order to be functional in a blackout, RTUs should not be dependent on ac power. RTUs, in general, are designed to be powered by dc from the station battery. The RTU interface equipment with the telephone system, such as amplifiers and equalizers, also should not use ac-powered equipment. Telephone companies generally try to use ac-powered equipment throughout their system, but utilities have a special need. Utilities should include periodic monitoring of RTU communication equipment as part of their routine inspections to ensure that it is not dependent on ac power.

D. Units Available for Service

The system restoration sequence and timing will be directly impacted by the various sizes, types, and state of operation of the system generating units prior to the blackout. The operating fossil, hydro, and combustion turbine units prior to the disturbance will likely be the most desirable units for the restart effort with the non-operating blackstartable units included among this group. The system operators will need to know throughout the restoration process the status and

availability of the system generating units. They also need to be alert to the influences of the weather and temperature and understand their potential to alter the availability of these units as well as their fuel supplies.

Determining the proper sequence for returning generating units to service also requires the gathering of known facts about the specific units beforehand. Having a tabulation of the individual unit characteristics and capabilities will be beneficial when selecting the order and fit of the units for the restoration sequence. This data will need to be compared to the actual serviceability of these units soon after the disturbance has occurred, with special emphasis placed on defining any changes to ramp rates, restart times, minimum or maximum load and var generation, or damage that occurred which might constrain unit operation. As many units as possible should be startable in parallel, although some will have to be done sequentially. Connected loads at plants and along circuits between plants also must be taken into consideration.

Auxiliary power should be restored to the generating sites as soon as possible to improve their availability. Relatively short delays in restoring auxiliary power can result in delays of several hours (or even days) in restoring the affected units. Station emergency generators and backup batteries may provide power for only the most essential safety systems but cannot be counted on as a source for a unit start-up.

E. Units Operating With Local Load

Units that have become isolated or islanded will not have the stability they would have if the system were normal. Units that have separated from the system, supplying their own auxiliary load or local area loads, will be at greatest risk of having frequency control problems if the actual unit load is less than the minimum load for the unit. Adding more station or distribution load or substituting fuels may increase the stability of the unit. However, any load added should be in small increments to prevent the unit from tripping and to better control the voltage and frequency fluctuations.

In some cases, the system operator may not be able to identify units that have separated from the system but are continuing to supply some load either to their own station auxiliaries or local areas. These units may appear to have tripped off-line based on observations of system control center generation stripcharts, frequency meters, load meters, and the like. Knowledge of the size and locations of these islands needs to be communicated to the system operators to enable them to choose the best strategy for the restoration effort and unit stabilization. When islanded areas can be identified, they should become the basis for connecting with adjacent islands as they become available.

F. Units With Blackstart Capability

The sources of start-up or cranking power, regardless of their type, need to be of adequate capacity to provide for the largest anticipated load plus any line charging requirements. For a remote combustion turbine or hydro site providing blackstart capability to another unit, line voltage between the source and load should be monitored and controlled close to the normal operating values. Adding shunt reactors may be necessary for var control if the reactive limits are exceeded on the generator(s) providing the cranking power.

At blackstart sites having multiple sources with which to provide remote cranking power, parallel unit operation will be required if the load is more than the output of one unit. Controlling these multiple units at no-load and then combining them into a single synchronized source will be necessary. As the cranking power path leaves the blackstart site, possibly entering substations or switchyard, breaker configuration will need to be examined to prevent unwanted loads from using power intended for units to be started or causing a trip-out of the blackstart sources.

G. *Scrubbers Availability After a Period Without Power*

The waste stream, thickening and transport sections of a “wet” flue gas scrubbing system, will be susceptible to rapid sludge thickening and solids set-up upon loss of power. For system equipment such as tanks, piping, rake drives, and pumps installed in unheated or outdoor locations, particular attention should be given to their sensitivity to low temperatures and freezing if not kept heated or drained of liquids. Spray lines and spray pumps would be recommended for draining and flushing as well. Creation of a solids settling time-line and a time-temperature curve might well serve as guidance to develop procedures.

An “dry” scrubbing system will typically have residual fluids and solids in its treatment/sorbent slurry, the atomizing system and recycle lines. A flushing and draining of these sections would be recommended even if installations are in heated areas. The ash transport lines for the associated bag house should be purged as well.

The power requirements to operate a unit’s scrubber system can demand a significant portion of the total station auxiliary power even under normal conditions. At some power stations, scrubbers can consume as much as 30 MW. During a system restoration, especially in the early stages, the power to operate a scrubber may better be directed to serving customer or other system needs. Operating temporarily without some portion of environmental controls also may be in the public’s best interest. An examination of the specific effects and risks of shifting these power uses to the customer should be considered.

H. *Nuclear Plant Status*

When a nuclear unit trips off-line and simultaneously the auxiliary power from the outside sources is lost, their site emergency generators are designed to start and supply the emergency or safeguard busses with power. Off-site power should be restored as soon as possible even though the unit start-up will be delayed. Upon the availability of off-site power to the non-safeguard busses, and assuming no equipment damage has taken place nor any radioactive leakage has occurred, a restart of the unit is possible.

Nuclear units require special treatment. NRC start-up checklists generally do not permit hot restarts and their diesels would not be permitted to supply auxiliary power to other stations. Nuclear units that are taken off line on a controlled shutdown can be restored to service in about 24 hours; more likely 48 hours after a scram. While restoring off-site power to nuclear units requires attention, restoring power to service area load will normally need to be without the help of nuclear units.

I. *Neighboring Systems*

In today’s operation of generation and transmission systems, few utilities are autonomous. Knowledge of the neighboring utilities’ status can enhance restoration through pooling restart sources, sharing reserves, and interconnecting transmission. Utilities should have functional communications to gain timely knowledge of the overall system status. Data links for system conditions in neighboring systems will aid in limiting the amount of verbal communications required. Special coordinating efforts will be necessary for facilities that are jointly owned or operated between two or more utilities.

J. *Personnel Availability*

System restoration requires utility personnel to complete an enormous amount of tasks in a relatively short time (less than 24 hours). It is essential for utilities to promptly get appropriate

off duty personnel notified to report to duty. Automatic notification systems can provide system and plant operators necessary relief of this burden. For effective use of extra personnel, utilities should consider defining responsibilities in advance of the event. Standing instructions for personnel expected to be involved should be to report to a designated site under blackout situations on their own initiative. Consideration must also be given for rotating personnel to keep fresh system and plant operators. Lists of contractors and the location of special tools and equipment should be available.

K. *Transmission Breaker Status and Connectivity*

After a system has blacked out, the system operators should perform a quick survey of the system status. Circuit breaker positions will not provide a reliable indication of faulted versus non-faulted equipment. Breakers will be found open from:

1. Permanent faults (storm related or equipment degradation), which may have initiated the system shutdown
2. Out-of-step conditions: As the system collapses, power flow on some lines may swing through the impedance characteristics of the line relays and trip the line. These lines will be usable in the restoration plans.
3. Temporary faults: As the system cascades into shutdown, some lines may overload, allowing the conductor to sag into underbuild or other right-of-way obstructions. After the fault is cleared and the conductor has cooled, the conductor will regain adequate clearance and will be serviceable.

Breakers can be found in the closed position, but the associated transmission facility is faulted. If the system blackout is storm-initiated, this condition is quite possible. The storm can continue to damage equipment after the system is de-energized.

Utilities operating in cold weather should be concerned about breakers= serviceability. In cold weather, breakers with leaks tend to leak more. After prolonged periods without ac power to compressors and heaters, enough pressure may not be available for circuit breaker operation. SF6 gas may condense into a liquid causing the breaker to lock out until heaters and compressors are restored. Clearly, station service should be restored as soon as possible.

L. *Transmission Facilities Unavailable for Service*

Because breaker positions cannot be relied on as an indicator of facility availability for service, the system operator should rely on field verified data (such as oscillographs) to determine whether or not equipment is faulted. Also, equipment with neutral connections, such as reactors, transformers, and capacitors, may be locked out from the neutral overcurrent conditions during system shutdown. These facilities may be in perfectly serviceable condition.

M. *Station Battery Effective Availability*

The station battery is one of the most critical pieces of equipment in the restoration process. Most utilities have standards for specifying the battery size. A common battery standard is to have enough battery capacity to handle an 8 to 12 hour outage of ac power to the battery chargers and still be able to serve all of the following:

1. All normal dc loads
2. The largest credible substation event at the beginning of the 8 to 12 hour period
3. One open-close-open operation on each substation device during the 8 to 12 hour period with some margin

The main concern with this specification is whether a blackout event will result in a greater initial dc load than the largest substation event. Also, will more than one operation be needed on each device before ac is restored to the substation?

Utilities may periodically test station batteries based on a substation theoretical load profile in a system blackout, not based on design criteria or manufacturer specifications. Testing based on design criteria of manufacturer specifications can mislead utilities as to their actual battery performance. Also, proper, routine battery maintenance is essential to battery performance in emergencies.

Utilities should periodically review the station battery loads to check for added loads, such as dc lights or dc heaters, that the battery was not designed to handle without an ac power source.

N. *Expected Relay System Reliability*

Most relay systems will remain reliable and secure during restoration, provided there is adequate fault current available to activate the relaying. The most questionable relay reliability issues come from reclosing relays. Utilities should review their restoration plans for impacts of inadvertent reclosure of breakers during energization. Restoration plans also should be reviewed for reclosing schemes that allow reclosing in a manner that is only suited for normal operation. Some examples are:

1. Station hot bus-dead line reclosing requires the main bus to be hot before a transmission line is reclosed. In a blackout, this scheme may prohibit energizing from a blackstart generator into a transmission station.
2. Peaking plants that tap a transmission line may require a hot line before allowing closure to the line. If this is a blackstart generator, energizing of the line may be prohibited until the relay is bypassed.
3. Motor operated air-break switches that may inhibit circuit restoration.

O. *Underfrequency Relaying Load Status*

Utilities should make the status and control of underfrequency relays available for the system operator through SCADA. The underfrequency relay operation indication should be identified and segregated by trip frequency so that the system operators know what underfrequency protection has activated and what is remaining.

Any block restoration of underfrequency load shed by underfrequency relays should be sequenced so that the entire block of load is not restored simultaneously, resulting in re-activating underfrequency, or in the worst case, causing the system to shut down again. Distribution circuits with capacitors and/or underfrequency relaying may want to be energized later in the restoration process to avoid voltage problems or automatic trips.

During much of the early stages of system restoration, customer service may be rotated, giving more customers an opportunity for some amount of service. The SCADA system load shed program should be designed to allow previously restored underfrequency load to be shed, and shed load restored.

P. *Generators Tripped by Underfrequency*

A unit separated from the system due to an underfrequency trip may have islanded and continue to generate power for its station auxiliary load. With no system load on the generators, the station

auxiliary demand will be quite small, and the steam generators output may be difficult to control. Immediate load addition may be required to keep the steam generator from tripping or having the steam turbine trip out on overspeed. Other units may be able to operate indefinitely on their auxiliary load.

For the units tripped and unable to maintain generation for their own auxiliary load, a complete restart would be necessary. Restart could commence with the return of station auxiliary power from an external source.

IV. Restoration of Auxiliary Power to Operable Generation

A. Evaluate Transmission System Status

A system blackout will generally cause much initial confusion and create a large number of SCADA alarms and reports. Efforts should be made to ensure that only essential alarms are given to operators under these and other emergency situations. Before generating units can be restarted, an accurate picture of the transmission and generation system should be developed. The first step of the restoration process should be an evaluation of the transmission system. Energy Management System (EMS) SCADA indications should be confirmed by dispatching field personnel or verify equipment status from other sources as required. This EMS SCADA data will be used during the restoration process and must be accurate if the process is to be successful. All known and/or suspected transmission damage should be identified. Work can then be initiated on damaged transmission facilities that are involved in the blackstart process, to either isolate or repair the damaged facilities, or to use alternate paths.

B. Evaluate Generation Resources

Generation resources in any system are constantly changing. This will be especially true following a partial or complete system blackout. The units that were on line during the event are now off line and in an unknown condition. Plant personnel should begin an immediate assessment and, as soon as possible, communicate unit status to the control center. This must be complete before the full restoration process can be initiated. This information will be used to develop a blackstart process based on actual unit availability. Enough units must be provided with auxiliary power to assure capacity to serve all customer load.

C. Fuel Supply Considerations

In a blackout event, especially a wide spread event, natural gas transmission facilities should be considered for priority power restoration if they are required as a fuel source for generation. Most, if not all, of those facilities do not have on-site emergency power. Transmission paths supplying start-up power for generating units also should support fuel delivery to those units.

D. Blackstart Process

Each system should have a blackstart plan including specific transmission and generation procedures to implement that plan. In an actual system blackout, the generation and transmission resources could be significantly different than anticipated. The primary focus of a restoration process is to connect available generation to a start-up power source. The information accumulated during the transmission system and generation resources evaluation should be used to develop a blackstart process utilizing actual available resources. The process should include the following:

1. Establish off-site power for nuclear units, both those that had been operating and those already off line. This is required without regard to using these units for restoring load.
2. Units with blackstart capability should begin the restart process for use in supplying start-up power to other units.
3. Priority access to start-up power should be given to hot units that can be returned to service immediately.
4. Priority access to start-up power also should be given to other units that can be started within a few hours.

5. Consideration should be given to connecting shunt reactor devices to help stabilize generating units being brought on line.
6. Transmission corridors for supplying start-up power should be identified and switching procedures determined, taking extra care to isolate damaged facilities.
7. Units without blackstart capability should be prepared to begin the start-up process when start-up power becomes available.
8. Transmission system corridors to support the start-up process should be established but not energized until needed.
9. As units with blackstart capability come on line, *energize* appropriate transmission system corridors supplying start-up power for units that are ready to return to service.

E. Procedure Testing

For blackstart units to achieve their maximum benefit, they should be tested periodically under realistic conditions. In addition to demonstrating that the units can in fact be started using designated facilities, this also provides training for the people involved with the process. Similar testing and training also is needed for units with load rejection capability. Isolating these units from the system when conditions permit and using the actual sources to start them is a worthwhile and revealing exercise. Problems that could seriously impact an actual restoration can be revealed under controlled conditions and corrected before they can impact an emergency. Similar testing and training also is needed for units with load rejection capability.

V. Preparation for the Transmission System Restoration

A. Restoration Switching Strategies

After determining the extent of the blackout and assessing the status of system equipment, the switching operations necessary for system reintegration represent a significant portion of the restoration process. Depending on the specific utility's requirements, there are two general switching strategies, which may be used to sectionalize the transmission system for restoration. The first is the "all open" approach where all circuit breakers at affected (blacked out) substations are opened. The second strategy is the "controlled operation" where only those breakers necessary to allow system restoration to proceed are opened.

The "all open" strategy can be effectively accomplished by local station operators or by automated EMS supervisory control. This approach has the advantage to the system operator of presenting a simpler and safer configuration to re-energize. Only breakers involved in the restoration process will need to be closed. System collapse or voltage deviations due to inadvertent load pickup or circuit energizing are less likely to occur. Drawbacks of the "all open" approach are that restoration time may be longer and more stored energy is required for the greater number of breaker operations. Stored energy in the form of compressed air or gas, springs, or station batteries is used to operate the breaker mechanism. Unless this energy is lost due to leakage or discharge due to operations during the blackout event, circuit breakers should be capable of one open-close-open operation without ac station service.

The Acontrolled operation≡ switching strategy imposes less (stored) energy requirements since breakers not involved in the initial sectionalization and restoration remains closed. However, the system operator must be continually aware of the isolation between the restored and de-energized systems. Studies should be conducted to examine steady state and transient voltage response if multiple transmission circuits are to be energized by the "controlled operation" strategy. Either strategy requires an extensive amount of switching operations, except that "controlled operation" will hopefully postpone some breaker operations until after station service is re-established.

B. Cold Weather Switching Concerns

In addition to the limited number of breaker operations during a blackout, switching operations can be further compromised following an interruption in cold weather. The proper operation of many transmission breakers (particularly air-blast and SF6) depends on maintaining the proper temperature and pressure within the breaker. This is normally accomplished by heating elements and compressors supplied by ac station service. A cold weather interruption reduces the time window for normal breaker conditions (as short as thirty minutes), after which operation may be blocked by electrical interlocks monitoring the breaker pressure. Although most breakers can be operated manually, this method normally requires the breaker to be de-energized for safety and restricts switching operations. If manual operation is required for energized breakers, breaker misoperation or damage may occur.

C. System Sectionalizing

Regardless of restoration switching strategy, system sectionalizing to disconnect load and capacitors from the transmission system is generally desirable. Unless load pickup is required when energizing transmission circuits for voltage control, loads should be disconnected and restored in small blocks for system frequency control. Opening of station and controlled distribution capacitors may help prevent high voltage and generator underexcitation conditions aggravated by charging current of unloaded transmission circuits. Shunt reactors are ideal

candidates for controlling high system voltage if studies show their use acceptable under weak system conditions. Transformer tap positions, especially load tap changers under automatic control, should be reviewed and moved if substantially off nominal. Generator voltage regulators should be in service to limit voltage deviations prior to load pickup or circuit energizing. Restoration of several subsystems in parallel and then tying them together may shorten the restoration process if manpower and facilities are available.

D. System Assessment

In preparation for an actual restoration, the effort to ascertain faulted system equipment will detract from the restoration process. Many transmission circuits may trip due to out-of-step relaying or temporarily sag and trip during the system collapse. These circuits may be serviceable for restoration, however, system operators should exercise care to avoid closing into a fault when energizing the transmission system. If possible, field personnel should check relay flags of tripped transmission circuits before energizing. Any verifiable failures must be factored into the restoration.

A utility restoration plan incorporating either the “all open” or “controlled operation” switching strategy must consider the impact of substation equipment availability following a blackout. Inoperable or failed equipment at key substations will require additional switching operations and may significantly delay the restoration effort. Utilities that rely on automatic restoration equipment at unattended stations not controlled by supervisory control must take operation of this equipment into account in developing restoration plans.

VI. Restoration of the Transmission System and System Loads

A. *Transmission Restoration*

1. Voltage Limitations

During restoration, the bulk power system should be operated so that reasonable voltage profiles (within the range 90% to 110% of nominal) can be maintained. Where possible, voltages should be maintained at the minimum possible levels to reduce charging currents.

When energizing transmission lines, care must be taken to make sure that nearby generators are on automatic excitation control and that enough Mvar reserve (or margin) is available at the generator to absorb the line charging. If the generator's underexcited capability is exceeded following the line energization, a voltage runaway situation may arise.

Once a line has been energized successfully, it is best to energize some local load to reduce the voltages. Successive energization of a line followed by that of a load will be a good strategy to control the voltages to within acceptable ranges. The system operators should attempt to balance the reactive requirements using line charging, and loading of shunt capacitors, reactors, and unit Mvar reserve capabilities. Transmission shunt capacitor banks should be removed from service to prevent high voltage until sufficient load has been re-energized. Shunt reactors should be placed in service when initially restoring the system to help reduce system voltages. Static var compensators and condensers under automatic control should be placed in service as soon as practical. Voltages need to be continuously monitored on all the transmission circuits, particularly those that provide inter-area ties.

2. Synchrocheck Interconnection Relay Schemes

Automatic reclosing relays should initially be disabled in order to prevent premature, uncontrolled, automatic reclosure of individual interconnections. Isolated areas should be synchronized using the highest voltage line available. This procedure is desirable because of the lower impedance and higher relay load ability of the higher voltage lines. However, possible overvoltages or special considerations could prompt the use of lower voltage lines.

Control areas, which share common transmission or generation facilities, must develop prearranged plans for the priority operation of these facilities during restoration. Interconnection should only be attempted at a generating plant or at a station with a synchroscope. Substations, which have the capability of synchronizing two systems, which are isolated, should be identified and included in each system restoration plan.

Where possible, field personnel should be used to verify breaker positions. When synchronizing, both phase angle across the breaker and the voltage on each side of the breaker should be measured. If possible, the phase rotation should be stopped and the phase angle reduced to ten degrees or less before interconnection is made.

3. Transmission Stability

Circuit energizations should be performed in a deliberate manner, checking the status of all associated facilities before and after energization. The system operator should aim low on voltage when energizing circuits to reduce charging currents. The energized

transmission must be monitored to control facility loadings and voltage conditions. Minimize the number of switching operations because: (1) excessive switching increased restoration time, and (2) until station service is restored to a substation, the breakers at that station can be operated only a relatively few times before they become inoperative due to loss of stored energy. Only energize transmission lines that will carry significant load. Energizing extra lines will generate unwanted Mvars.

Prior to energizing a line section, the system operator should attempt to keep the voltage on the source bus below its nominal value. Open shunt capacitors and close shunt reactors before re-energizing transmission lines. If minimum source requirements have been established for a transmission line, the system operator must ensure that those requirements have been met before energizing the EHV line. Minimum source requirements address the concerns associated with:

- a. Steady-state overvoltage caused by excessive var supply from the capacitive rise of EHV lines and aggravated by harmonics from transformer saturation.
- b. Transient overvoltage caused by traveling wave phenomena.
- c. Dynamic overvoltage caused by transformer magnetizing inrush and aggravated by harmonics from transformer saturation.
- d. Reduction in proper relaying protection reliability due to insufficient fault current and overvoltage failure of EHV equipment.

Where possible, ac load flow analysis should be used to examine steady-state voltage levels, and switching surge studies should be used to identify transient problems. These must be representative off-line studies prior to the incident until practical real-time analysis is developed.

If an EHV line is to be energized by closing the breaker on the low side of the transformer, consideration should be given to adjusting the tap changer to its studied position or in the absence of a specified setting to its lowest EHV tap setting. On an open-ended EHV transformer that will be energized with an EHV line, adjust the tap changer to the studied tap position, to its normal or midpoint position, or to match the energized line voltage. Ferroresonance may occur upon energizing a line or while picking up a transformer from an unloaded line.

4. Fault Availability for Proper Relay Operation

Low available short circuit current can hinder the performance of protective relaying. Because of a higher likelihood of overvoltage, and thus system faults during restoration, proper relay protection is imperative to prevent recollapse of a weak system. Primary and backup EHV relaying should be in service on all lines being returned to service. The system operator should assure that adequate underlying transmission capability is electrically connected at the interconnection point to provide adequate fault current (relay protection). Impedance relays that do not have out-of-step blocking may trip lines due to power swings during restoration.

5. Transient Problems in Energizing Transmission

Various factors affect the transient stability of a system, such as the strength of the transmission network within the system and of the tie lines to adjacent areas (if any), the characteristics of the generating units, including the inertia of the rotation parts, and the electrical properties such as transient reactance and magnetic saturation characteristics of the stator and rotor iron. The stronger (i.e., lower source impedance) and the more numerous the lines on a bus, the less severe the energizing transients become. In

addition, connecting shunt reactors to the line especially at the remote end of the terminal to be switched, will lower the energizing voltages.

Severe overvoltages resulting from switching surges may cause flashover and serious damage to equipment. Switching transients are fast transients that occur in the process of energizing transmission line and bus load capacitances right after a power source is connected to the network. The transient voltages or switching surges are caused by energizing large segments of the transmission system or by switching capacitive elements. The switching transients, which are usually highly damped and of short duration, in conjunction with sustained overvoltages, may result in arrester failures.

Transient overvoltages are not usually a significant factor at transmission voltages below 100 kV. At higher transmission voltages, overvoltages caused by switching may become significant because arrester operating voltages limits are relatively close to normal system voltage and lines are usually long so that energy stored on the lines may be large. In most cases, without sustained traveling wave transients, surge arrestors have sufficient energy absorbing capability to damp harmful overvoltages to safe levels without permanent damage. Also, circuit breaker closing resistors will provide enough damping of switching surges for closing long lines.

B. Generation

1. Unit Stability

As system restoration progresses and more generating units return to service, the more stable the system becomes. More units mean stronger sources in terms of synchronized inertia and control of frequency and voltage. Stronger sources will afford more circuit energizations, unit start-ups, spinning reserve, and load pickups. However, caution needs to be observed during this period. There should be sufficient time between switching operations to allow the generating units to stabilize from sudden increases in load.

Automatic governor controls on generators should be placed in the automatic position to ensure instantaneous governor response to changes in frequency. Generating units should be loaded as soon as possible to a load level above their minimum loading point to achieve reliable and stable unit operation.

2. Load/Frequency Control in Area Islands

Generation and load should be adjusted in small increments to minimize the impact on the frequency. Loads should be added in block sizes that do not exceed 5% of the total synchronized generating capability. Frequency should be maintained between 59.75 Hz and 61.00 Hz with an attempt made to regulate toward 60.00 Hz. Manual load shedding may need to be used to keep the frequency above 59.50 Hz. As a guide, shed approximately six to ten percent of the load to restore the frequency 1 Hz. Large segments of load should only be restored if the frequency can be maintained above 59.90 Hz, and it is certain that such action will not jeopardize the transmission system of other paralleled areas. It may be helpful to increase the frequency to slightly above 60.00 Hz before each load block addition in the early restoration stages.

Even with the advantages of load with underfrequency relays enabled, it is advisable to resist picking up this type of load unless normal load pickup has been demonstrated to not cause frequency decay below the applicable underfrequency trip level. When load with underfrequency relays enabled is being picked up, it may be advisable to restore the load by alternating load pickup at each of the various underfrequency steps.

When interconnecting with another system, the frequency should be matched and maintained above 59.75 Hz and below 61.00 Hz. Anytime two or more isolated systems are operating in parallel, only one system should control frequency with the other system(s), controlling tie schedules unless load frequency control (LFC) is available. The best regulating units on the system should be used to regulate area or island frequency. The best units should be determined based on both the amount and quality of regulation provided. If the frequency regulation burden becomes too large for one unit, the frequency regulation should be shared by two or more units, preferably in the same plant control room for better coordination. If more than one area controls frequency, there would be a hunting effect without LFC. As a general guide, the regulation requirement to maintain frequency during system restoration should be about twice the normal requirement for the area load being carried at that time. Units not assigned to regulate frequency should be constantly redispached to keep each regulating unit's energy at the middle of its regulating range.

3. **Spinning Reserve**

During system restoration, each control area should carry enough operating reserve to cover its largest generator contingency in each isolated area. This reserve can either be on-line generation that can produce additional power within ten minutes or customer load that can be shed manually within ten minutes. Operating reserve is required to enable the control area to restore its area (or subsystems) to a pre-contingency state (both tie lines and frequency) within ten minutes of a contingency. The smaller the area, the more of this reserve should be spinning. Connecting two or more systems together may result in a lower combined operating reserve requirement. However, caution needs to be used to ensure that load is not added too fast and the system collapses again.

C. Load Pickup

1. **Cold Load Pickup**

Restoring customer load to service, which has been disconnected for some time, presents new challenges. The disconnected load will probably be much higher than its value at the time of interruption. The simultaneous starting of motors, compressors, etc., will cause high peak demands for power. These higher than usual load requirements are commonly referred to as cold load pickup. Cold load pickup can involve inrush currents of ten or more times the normal load current depending on the nature of the load being picked up. This will generally decay to about two times normal load current in two to four seconds and remain at a level of 150% to 200% of pre-shutdown levels for as long as 30 minutes. When restoring load, sufficient time must be allowed between switching operations to permit stabilizing the generation.

2. **Priority Customers**

Each control area should develop a priority restoration scheme for its customer load. These load restoration schemes need to address the control area's requirements as well as those of the community. Providing station service to nuclear power plants and providing service to facilities necessary to restore the electric utility system should be the highest priority.

As conditions permit, the system operator should consider providing service to critical loads such as generating plant fuel supply depots, military facilities, law enforcement organizations, facilities affecting public health, and public communication facilities.

3. **Automatic load Restoration Schemes**

The system operators need to control and remain in control of all aspects of the system restoration. Automatic devices, which protect the system (relays, voltage regulators, etc.) should be in service as quickly as possible. Other automatic devices such as automatic load restoration schemes should not be enabled until a sufficient portion of the system generation and load have been restored unless the possibility of automatic restoration is factored into the portion of the system being energized.

VII. Reliability Coordinator Responsibilities During Restoration

A. *Early Restoration Stages*

1. Communications

The Reliability Coordinator's primary role in the early stages of power system restoration is to coordinate the exchange of information among the systems under the Reliability Coordinator's purview (the Reliability Coordinators' "members"), other Reliability Coordinators, NERC, and the Regions. The Reliability Coordinator should initially endeavor to establish lines of communication with its members via normal systems or, lacking those, through any available means. As soon as practical, the RC should establish communications with other Reliability Coordinators and NERC via the NERC hotline and Reliability Coordinator Information System or, lacking those, through any available means. Communications with the Regions should be on an as-needed basis. Information to be gathered from members and exchanged with other Reliability Coordinators and NERC would typically include:

- The extent of the required restoration effort in the Reliability Area (transmission and generation facilities not available for service).
- High-level summaries of the members' initial plans to begin restoration.
- The progress being made to restore generation capacity (for example, key generating facilities restored, milestones achieved associated with generation, etc.).
- The progress being made in restoring transmission facilities (for example, a list of bulk power substations re-energized, milestones achieved associated with transmission, etc.).

2. Information Sharing

Information from other Reliability Coordinators or NERC to be shared with members would typically include:

- Status of power system restoration progress in adjacent Reliability Coordinator areas.
- Information regarding the cause of the system collapse.

B. *Later Restoration Stages*

As the power system restoration process progresses, the responsibilities of the Reliability Coordinator increase. The Reliability Coordinator should:

- Work with the Control Area Operators to review the power system data to facilitate the RC's real-time data acquisition in order to determine the overall state of the power system.
- Work with the Control Area Operators in order to ensure that sub-regional switching is coordinated as the system is restored.
- Work with the Control Area Operators and neighboring Reliability Coordinators to determine when interconnections in adjacent Reliability Coordinator areas can take place.

Throughout the restoration process, the RC should assess its ability to perform the RC functions required by NERC Policy 9. As system conditions and data availability permit, the RC should verify that it has successfully restored its ability to perform each function.

C. *Reliability Coordinator Training*

Reliability Coordinators should have knowledge of the restoration plans and procedures within their defined area of responsibility. Restoration drills plus other training as needed should take place on an annual basis.

VIII. Training and Testing

The development of training and testing for electric system restoration requires careful consideration and is specific to each utility. From a global perspective, however, the utilities within a control area should share common objectives. In order to enable each utility to develop an effective training plan, this section will focus on presenting a training schematic. Employee input and involvement are the prime catalysts in all aspects of training.

A. Goals

The area utilities should first develop training goals by listing the objectives specific to each utility. The goals should encompass conditions, concerns, contingencies, post-outage generation resource forecast, automatic circuit breaker operations, training needs of personnel, and procedures specific to the area.

Typical area goals might be expressed as follows:

1. “Provide electric system restoration training for system operations personnel in order to build confidence, optimize effectiveness, and nurture teamwork.”
2. Provide a basis for better communications concerning electric system restoration between utilities and groups within utilities.≡

B. Decision Making and Priority Setting

Training priorities should be set in order to make tough decisions regarding the depth and focus of training. The backgrounds and needs of utilities vary, so the training program of each also may vary from that of a neighboring system.

Training tasks should be identified which will help attain the goals. The training tasks identify the nature of training, but do not say how to do it. Priorities must be established for the training tasks. The tasks and priorities should be developed and scrutinized by employees closest to the daily operations.

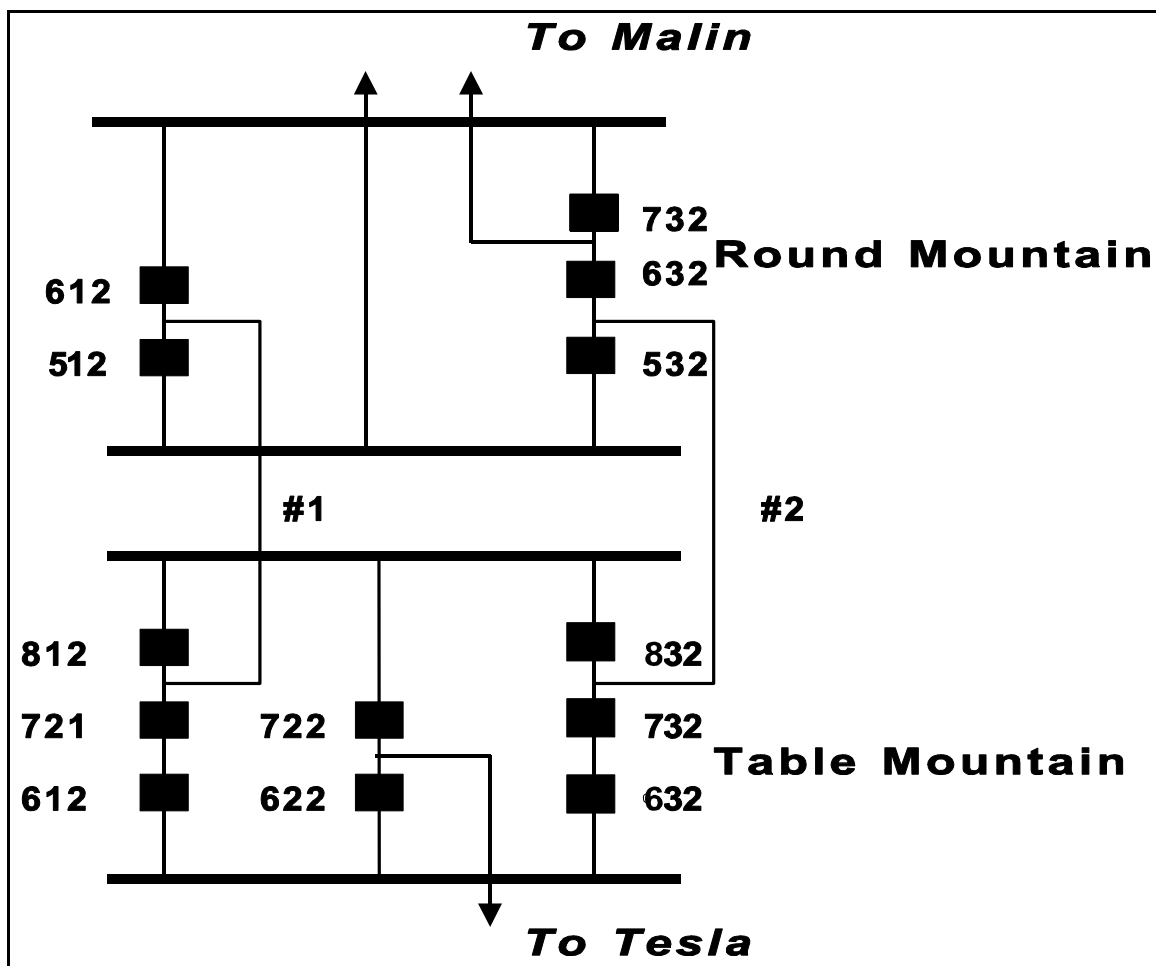
Typical restoration training priorities include the following:

1. Enhance understanding of anticipated post-collapse system conditions and alarms.
2. Review existing dispatching instructions and procedures.
3. Develop and be prepared to use a functional restoration diagram for tracking system restoration down to and including major 115 kV, such as the example shown in Figure 2.
4. Refine and update system restoration procedures using simulation if available.
5. Study and project response to restoration procedures regarding generation sources, interconnections, AGC control mode, frequencies, governor bandwidth, voltage rise, relaying parameters of potential impact, backup control center, and voltage change anticipated from reactive changes at substations with little or no power flow.
6. Promote increased awareness of problems arising from picking up load with isolated generation, including frequency deviation anticipated, potential distribution underfrequency relay action, potential generation overspeed trips in response to distribution load trips, frequency control methods, reactive control, maintaining unit stability, increasing frequency by 0.5 to 1.2 Hz before incremental load pickup, and control of electrical system load being restored.
7. Knowledge of problems associated with attempting to pick up portions of the system while avoiding restoration of uncontrolled loads by automatic controls or field personnel actions when necessary.

8. Familiarization with specific devices for use in controlling line voltages: EHV line shunt reactors, tertiary shunt reactors, unloaded banks, banks with controlled amounts of load, synchronous condensers, static var compensators, bypassing series capacitors, and the anticipated magnitude of the voltage change to be realized from each action.
9. Encourage teamwork within each control center and between control centers.
10. Promote coordinated response and understanding across corporate cultural lines of plants, divisions, regions, and business units or other organizational boundaries.

C. Methodology

Each utility should construct a plan for implementing restoration training, outlining how the training will be done. The methods developed should be focused upon providing the training tasks, which serve to accomplish training goals. In addition, the methods proposed should be subjected to a review to ensure the methods can be supported. Suggested prerequisites to consider for checking to ensure that training can be supported include practicality, human resources required to accomplish, support by involved parties, and budget allocation.



Some training methods might include the following:

1. Classroom review of critical technical information and reference to procedures, including automatic generation control (AGC) modes, frequency sources for AGC, coordination, power pool or coordinating council notification procedures, loading or stability

- constraints, detailed procedures for specific plants or portions of the system, and equipment voltage limits.
2. Simulator demonstrations involving isolated system response.
 3. Simulator demonstration of voltage changes by various voltage control methods.
 4. Guest speakers for classroom PC slide show presentations on remedial action, special protection schemes, contingency studies, and protective relaying impact on restoration.
 5. Simulator or classroom work group assignments to respond to total system blackout and take actions up to and including total system restoration. Suggested scenarios should include both with and without outside sources of generation or supply.
 6. Simulator restoration or work group assignments may be combined into contiguous segments:
 - a. System analysis
 - b. Assignment of responsibilities
 - c. Determination of plan(s) to implement linking resources with critical needs, such as nuclear plants and control centers
 - d. Restoration and express routes for linking first resources with power plants
 - e. Bulk load restoration
 - f. Subsequent day's load reduction measures or rotating outage implementation if resources are insufficient at peak.

D. Testing Equipment and Procedures

In addition to training, possible simulation, and operations preparedness, the communication links and procedures within and between utilities should be Atested≡ by means of periodic use and, if possible, training drills or exercises.

E. Measuring Effectiveness

It is recommended that measurements be established to determine the effectiveness of restoration training. The measurements may be suited to individual needs, but may include:

1. Training results critique to be completed by the people being trained
2. Annual system restoration knowledge level questionnaire
3. On-the-job evaluation of restoration knowledge

Any demonstrated application in restoring smaller parts of the system also can be included. The desirability of measuring training effectiveness is now perceived by many as a preferred strategy rather than that of testing individuals. It is most difficult to test an individual's operating ability without simultaneously lessening the focus upon learning. Each utility must determine the best strategy in view of specific needs, goals, and resources.

All aspects of restoration are extremely important. However, the mere presence of procedures does not ensure optimum response. Training is an important element, which can bridge the gap between what we want to happen and what will really happen with respect to restoration. The NERC Operating Guides and associated appendices are excellent resources for training assessment and development.