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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.
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.”


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-sellling 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
A History of NERC

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

7. NERC released its *Study on NOx 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.
A History of NERC

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.
Organization and Procedures Manual
For NERC Standing Committees

Approved by the Board of Trustees on
June 10, 2003

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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 website 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 Committees** — manage the assessment, monitoring, and enforcement of compliance with reliability standards. These committees also manage the certification of reliability service organizations and personnel.

- **Critical Infrastructure Protection Advisory Group** — advises the Board on matters related to the physical and cyber security of the electricity infrastructure of North America. The Critical Infrastructure Advisory Group 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.

Approved by NERC Board of Trustees: June 10, 2003
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.

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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

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.
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.
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.
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

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.
• 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 nonvoting 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.
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, the chairman and a vice chairman of the Critical Infrastructure Protection Advisory Group (CIPAG), 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, such as officers of the Standards Authorization Committee or compliance and certification committees, or others.

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 three 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 three 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.
Inter-Committee Coordination

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

The following list summaries 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.
Transitional Process for Revising Existing NERC Operating Policies and Planning Standards

October 8, 2002
Transitional Process for Revising Existing NERC Operating Policies and Planning Standards

Introduction
This document explains the transitional process for revising NERC’s existing body of Operating Policies and Planning Standards to deal with situations where the existing Operating Policies or Planning Standards, if left unchanged, pose a substantial risk of adverse effects on either reliability or commercial markets.

The NERC Board recently approved a new Organization Standards Process Manual that defines the process for developing new Organization Standards. NERC Organization Standards are intended to restate the rules needed for reliable operation of the bulk electric system in terms of the new Industry Functional Model that NERC’s Board of Trustees approved in June 2001. Over time, Organization Standards will displace NERC’s existing Operating Policies and Planning Standards. In the meantime, this transitional process will assure that any necessary revisions to existing Operating Policies or Planning Standards will be developed in a fair, open, balanced, and inclusive manner.

The electric industry is also in the process of establishing a new organization to develop business practice standards and communications protocols for the wholesale electric industry. At some point, standards developed by that new organization may also displace aspects of NERC’s existing Operating Policies and Planning Standards.

Issues Requiring Immediate Action
In circumstances where immediate action is needed, the Executive Committees of the three Standing Committees may submit a proposed revision to an Operating Policy or Planning Standard directly for ballot to the 105 members of the three Standing Committees (Steps 7 and 8). If approved, any such revision will automatically terminate after one year unless:

1. The revision is re-balloted and approved by the Standing Committees (Step 8 – Standing Committees Ballot the Revised Operating Policy or Planning Standard) after following all steps in the transitional process, or

2. The Standing Committees agree the revision is no longer needed, or

3. The Standing Committees agree by ballot to extend the date, or

4. The Standing Committees agree that the revision should be referred to the Wholesale Electric Quadrant of the North American Energy Standards Board as a proposed electric business practice standard.

(See Step 2 – Executive Committees Review Request for additional details.)
Transitional Process Steps

Step 1 – NERC Receives Request to Revise a Policy or Standard
Any individual or organization with a legitimate interest in electric system reliability, including any NERC subgroup, may submit a request to revise an existing Operating Policy or Planning Standard. Such requests should be submitted in writing (preferably by e-mail) to the NERC staff and include:

1. Name of Operating Policy or Planning Standard
2. Brief explanation of the proposed revision and whether it requires immediate action
3. Justification for using this transitional process, with a discussion of the consequences of not revising the Operating Policy or Planning Standard as suggested, including possible adverse effects on either reliability or commercial markets
4. Complete draft of proposed revision (if available)

The NERC staff will forward the request to the Executive Committees of the Standing Committees.

Step 2 – Executive Committees Review Request
The Executive Committees of the Standing Committees will review the request based on:

1. The risk of adverse effects on either reliability or commercial markets if the Operating Policy or Planning Standard is left unchanged, and
2. The current Standards Authorization Requests to determine if NERC is already developing an Organization Standard that addresses the same issues, and
3. Work underway by the Wholesale Electric Quadrant of the North American Energy Standards Board

The Executive Committees will then decide on one of the following actions:

1. Approve proceeding with the requested revision.
   a. If necessary, assign the request to the NERC subgroup responsible for the Operating Policy or Planning Standard proposed for review and further development as appropriate.
   b. **If immediate action** is needed:
      i. Proceed to Step 7 – Executive Committees Decide to Proceed to Ballot and,
      ii. Determine if a special meeting of the Board of Trustees is needed to approve the revision in Step 10 – Board Approval
2. Ask the requestor to submit a Standards Authorization Request for an Organization Standard instead. 1
3. Refer the request to the Wholesale Electric Quadrant of the North American Energy Standards Board as a proposed wholesale electric business practice standard
4. A combination of 1, 2, and 3
5. Reject the request

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1 In this case, the requestor will follow the Organization Standards Process Manual instead of this Transitional Process.
Transitional Process for Revising Existing NERC Operating Policies and Planning Standards

Step 3 – Subgroup Drafts Revision and NERC Announces on Web Site
The Subgroup assigned to develop a draft of the revised Operating Policy or Planning Standard will provide the NERC staff a summary of the revision it expects to draft. The NERC staff will post the announcement and revision summary on the NERC web site and send the announcement to all parties that subscribe to the NERC Standards e-mail list server. The announcement will indicate approximately when the proposed revision will be posted for comment.

Next, the Subgroup will prepare its first draft of the revised Operating Policy or Planning Standard. The draft will include specific measurements for determining compliance, where appropriate.

Step 4 – NERC Posts Draft Revision for Comment
When the Subgroup finishes its revision, the NERC staff will post the draft revision on the NERC web site and provide 45 days for comments. NERC will solicit comments on the revision from all interested parties. NERC will accept all comments, but comments must be supplied by e-mail. NERC will then post all comments it receives on its web site.

Step 5 – Subgroup Deliberates on Comments and Edits Revision
Based on the comments it receives, plus its own review, the Subgroup will edit the draft revision as needed. It will document its responses to all comments received, and the NERC staff will post these responses on the NERC web site.

The subgroup will decide on one of these two actions:

1. If the Subgroup believes the technical comments do not require substantial changes to the draft revision, the Subgroup can submit the draft revision to the Standing Committees for discussion and possible ballot in Step 6 – Subgroup Submits Draft Revision for Standing Committees.

2. If the Subgroup believes the technical comments are significant enough to warrant substantial changes to the draft, the Subgroup will repeat Step 3 – Subgroup Drafts Revision and NERC Announces on Web Site and Step 4 – NERC Posts Draft Revision for Comment before sending its final draft to the Standing Committees.

Step 6 – Subgroup Submits Draft Revision for Standing Committees’ Discussion
The NERC staff will post the Subgroup’s final draft revision and its responses to all comments on the NERC web site at least 30 days prior to the next regular meeting of the three Standing Committees.

Objections. If the Subgroup rejects a party’s technical comments, that party may send an objection to the NERC staff within 15 days of this posting. The staff will forward the party’s objection to the three Standing Committees for their consideration.

Balloting recommendations. The Subgroup will also recommend how the revision should be balloted — that is, whether the revision should be balloted in its entirety or in sections. If the latter, then the subgroup will recommend the subdivision of the revision.

The NERC staff will include the following information in the Standing Committees’ agendas for discussion:

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2 Interested parties may attend NERC subgroup meetings after registering with the NERC staff. Registration information is included with meeting announcements.
Transitional Process for Revising Existing NERC Operating Policies and Planning Standards

1. Final draft revision
2. Public comments and Subgroup responses
3. Comments on which the Subgroup did not agree
4. Objections to Subgroup responses

Indication to Proceed to Ballot. During their discussion, the Standing Committees will indicate whether they wish to proceed to ballot the suggested revision or whether additional revisions are needed.

Step 7 – Executive Committees Decide to Proceed to Ballot
The Executive Committees will review the Standing Committees’ discussions of the suggested revision and their desires to proceed to ballot. The Executive Committees will then decide on whether or not to proceed to ballot.

Proceed to ballot. If the Executive Committees agree to proceed to ballot the revision, the NERC staff will post the final draft of the revised NERC Operating Policy or Planning Standard, and then announce a 10-day ballot period. Proceed to Step 8 – Standing Committees Ballot the Revised Operating Policy or Planning Standard

Decision not to ballot. If the Executive Committees decide not to ballot the revision, the NERC staff will notify the Standing Committees and post the Executive Committees’ decision and explanation on the NERC web site. No further steps are necessary.

Immediate action. If the Executive Committees agree that immediate action is needed, they will instruct the NERC staff to prepare and post the necessary background material with an announcement at least 15 days prior to the start of the ballot period.

Step 8 – Standing Committees Ballot the Revised Operating Policy or Planning Standard
The voting members of the Standing Committees will send their ballot within the 10-day ballot period via e-mail to the NERC staff for recording. A Committee member may vote “yes,” “no,” or “abstain.”

The revision is approved when the following are satisfied:

1. A quorum, which is established by at least 50% of the voting members of the Standing Committees submitting a response with an affirmative vote, a negative vote, or an abstention; and
2. A two-thirds majority of votes cast are affirmative. The number of votes cast is the sum of affirmative and negative votes, excluding abstentions and non-responses.

In general, any “no” votes on a proposed revision should be accompanied by a written explanation of the “no” vote and, if possible, specific language that would make the revision acceptable.

If the Standing Committees approve the revision, proceed to Step 9 – Prepare for Board Consideration.

Revision not approved. If the revision is not approved, the Standing Committees may return the revision to the Subgroup for further work or they may terminate this Process with an appropriate notice to the original requestor. The NERC staff will post the following information on its web site:

1. Final draft revision
2. Standing Committees’ ballot results, including explanations of “no” votes
3. Standing Committees’ decision on further work
No further steps are necessary.

**Step 9 – Prepare for Board Consideration**
If the Standing Committees approve the revision, the NERC staff will post the following information on its web site:

1. Final draft revision
2. Public comments and Subgroup responses
3. Standing Committees’ ballot results, including explanations of “no” votes
4. Standing Committees’ minority opinions
5. Date of expected Board of Trustees consideration

**Objections.** A party who objects to the Standing Committees’ action may write to the NERC staff within 15 days of this posting.

The NERC staff will include Items 1 – 4 above, plus all objections to the Standing Committees’ actions, in the Board of Trustees’ meeting agenda.

**Step 10 – Board Approval**
At a regular or special meeting, the Board will review and vote on the proposed revision to the existing Operating Policy or Planning Standard. It will consider the Standing Committees’ ballot results and minority opinions, all comments that were not incorporated into the draft revision, and any filed objections to the Standing Committees’ actions. To preserve the integrity of this Process, the Board may not amend or modify a proposed revision.

**Revision not approved.** If the revision is not approved, the Board may return the revision to the Standing Committees for further work or it may terminate the activity with an appropriate notice to the original requestor and the Standing Committees. These Board actions will also be posted.

**Step 11 – Implement Revision to Operating Policy or Planning Standard**
If approved, the NERC staff will post the revision on the NERC web site, update the Operating Manual or Planning Standards, and notify all parties.

Once a revision to an existing Operating Policy or Planning Standard is approved by the Board, all industry participants are expected to implement and abide by the revised Policy or Standard in accordance with NERC bylaws.

**Further objections and appeals.** Should a party continue to object to the revision, that party may request, either through its Regional Council, electric industry organization, or directly, that the Board consider using NERC’s alternative dispute resolution procedure to address its objections. Any and all parties to this Transition Process retain the right of appeal to other authorities as the law allows.

**Immediate actions.** The Board may take action without a meeting\(^3\) in circumstances requiring immediate action.

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\(^3\) Procedures for Board Action Without a Meeting are specified in the NERC bylaws.
Introduction

The Operating Committee expects that there will be instances when an “Entity” – CONTROL AREA, RELIABILITY COORDINATOR, TRANSMISSION PROVIDER, etc. – will not be able to comply with an Operating Policy for various reasons, such as:

- The Entity performs an operating function in a way, which may be new or different, that the Policy does not accommodate, or
- An Operating Policy does not consider certain operating situations to which the Entity is subjected, and, if the Entity complies with the Policy, would jeopardize its or the INTERCONNECTION’s security, or
- The Entity believes the Operating Policy unduly discriminates against market participants, or
- A local or federal regulation will not allow the Entity to comply with the Policy.

Under these situations, the entity may request from the Operating Committee a waiver from compliance with the Policy. The waiver must include the specific alternative to the Policy that the Entity wishes to follow. The waiver, if approved, is temporary, and allows the Operating Committee the time it needs to resolve the conflict:

1. Review the request with the Subcommittee responsible for the Policy,
2. Decide if granting the waiver has operating security or marketing implications,
3. Grant the waiver and draft a revision to the Policy to accommodate the entity’s request permanently if appropriate, or
4. Deny the request for the waiver.

If the waiver is denied, the Entity will be expected to comply with the Policy as written.
Waiver Procedure

1. Waiver request. The Entity seeking a waiver to any Operating Policy shall send its request in writing (preferably via the Internet) to the Secretary of the Operating Committee. The request shall include the following information:

   1.1. Specific Policy for which waiver is requested. The Entity shall indicate the Policy name and outline number(s) of the specific Requirements or Standards.

   1.2. Explanation for request. The Entity shall explain the reason(s) for requesting the waiver. These might include:

      1.2.1. Policy adversely affects security. If the Entity believes the Policy will adversely affect the operating security of itself or the INTERCONNECTION, it must explain its reasons and provide a recommended change to the Policy that would mitigate this effect.

      1.2.2. Policy not needed. If the Entity believes the Policy is not needed, it must explain its reasons and explain how 1) existing Policies are adequate, or 2) that the Entity would prefer to follow a local or Regional policy that will provide the same reliability to the INTERCONNECTION, or 3) the operating situation does not exist for which the Policy was written.

      1.2.3. Policy violates law, tariff, or regulatory order. If the Entity believes the Policy violates a federal, state, or local law, or violates a filed tariff or regulatory order, it shall provide an explanation.

      1.2.4. Policy unduly discriminates against market participants. If the Entity believes the Policy unduly discriminates against market participants, it shall provide an explanation and provide a recommended change to the Policy that would mitigate this effect.

   1.3. Details of the waiver. The Entity shall explain the waiver it is requesting, including an explanation of how the entity will operate in lieu of the Policy for which the waiver is requested to ensure operating security to itself and the INTERCONNECTION, and that will not unduly discriminate against the marketplace.

2. Request submitted to Subcommittee for review. The Secretary of the Operating Committee shall review the request, and, after ensuring the requirements in Section 1 of this procedure are met, shall forward the request to the subcommittee responsible for the Policy. The Subcommittee must determine whether 1) a Policy revision is necessary, or 2) the waiver request should be denied.

3. Subcommittee decision submitted to Operating Committee or Operating Committee Executive Committee for deliberation. The Subcommittee will then forward its decision to the Operating Committee secretary who will, in turn, forward it to the Operating Committee (or OC Executive Committee if prompt action is necessary and the next regular OC meeting is more than two weeks away) for final approval. The Operating Committee or Executive Committee may either grant or deny the waiver request:

   3.1. Waiver granted. If the Operating Committee determines that the waiver should be granted, it will allow the waiver to become effective immediately (or on the date requested by the entity), direct the Subcommittee to proceed with drafting the necessary
revisions to the Policy, and inform the Board of Trustees of its decision. The Operating Committee must also set an expiration for the waiver if the Entity has not established one.

3.2. **Waiver denied.** If the Operating Committee determines that the waiver should be denied, it will notify the requesting Entity along with an explanation of the denial. If the waiver had been requested by the Entity on the premise that the Policy violated a law or regulatory rule, the Operating Committee will direct the subcommittee responsible for the Policy to work with the Entity to develop an alternate waiver, and, if necessary, work with the regulatory authority.

4. **Board notification.** The Operating Committee shall notify the NERC Board of Trustees at its next regular meeting of all waiver requests and Committee decisions. This notification shall include the name of the requesting Entity, the reason for the waiver, and its term.

5. **Revocation.** The Operating Committee can revoke a waiver if it determines that the waiver has an adverse effect on Reliability or the Marketplace, or if the situation for requesting the waiver no longer exists.

**Waiver Request Example**

<table>
<thead>
<tr>
<th><strong>Entity</strong></th>
<th>ABC Control Area</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Policy</strong></td>
<td>Policy 9, “Security Coordinator Procedures”</td>
</tr>
<tr>
<td><strong>Waiver Requested</strong></td>
<td>Request waiver of compliance with entering Interchange Transactions from XYZ into the Interchange Distribution Calculator.</td>
</tr>
<tr>
<td><strong>Explanation</strong></td>
<td>XYZ is connected to the INTERCONNECTION via a single tie line to ABC. Interchange Transactions from ABC to XYZ or XYZ to ABC do not flow over any other transmission facilities in the INTERCONNECTION.</td>
</tr>
</tbody>
</table>
Waivers

1. **Scheduling Agent**
   Organization – RTO CONTROL AREA Participants

2. **Financial Inadvertent Settlement**
   Organizations – Alliance RTO, Midwest ISO, Southwest Power Pool

3. **Control Performance Standard 2**
   Organization – ERCOT

4. **Tagging Dynamic Schedules and Inadvertent Payback**
   Organization – WECC

5. **Energy Flow Information**
   Organization – Midwest ISO

6. **Enhanced Congestion Management (Curtailment/Reload/Reallocation)**
   Organization – Midwest ISO, PJM Interconnection, L.L.C.

7. **Enhanced Scheduling Agent**
   Organization – Midwest ISO

8. **Western Interconnection Thresholds to Initiate Manual Corrections for Time Error**
   Organization – Western Interconnection, viz., the Western Electricity Coordinating Council (WECC)

9. **RTO Inadvertent Interchange Accounting**
   Organization – Midwest ISO
Waiver Request – Scheduling Agent

Organization
The Control Area participants of:

- Alliance RTO
- Midwest ISO
- Southwest Power Pool
- Grid South

Operating Policy
The CONTROL AREA participants request approval of this Waiver to implement a proposed RTO Scheduling Process to meet the RTO obligations under Order 2000, simplify TRANSACTION information requirements for market participants, reduce the number of parties with which CONTROL AREA operators must communicate, and provide a common means to tag TRANSACTIONS within and between RTOs.

The participants are requesting a Waiver of specific provisions of NERC Policy 1, “Generation Control and Performance,” and Policy 3, “Interchange,” to accommodate a RTO Scheduling Process. The RTO participants propose the following definition of a SCHEDULING AGENT:

SCHEDULING AGENT. A function with the authority to act on behalf of one or more CONTROL AREAS for INTERCHANGE SCHEDULE implementation including creation, confirmation, approval, check-out and associated INADVERTENT INTERCHANGE accounting.

The following specific sections of NERC Policy 1 Version 1a, “Generation Control and Performance,” and Policy 3, Version 4, “Interchange,” are affected by the RTO Scheduling Process proposed in this Waiver request:

Standards
Policy 1
- Policy 1F, “Inadvertent Interchange Standard”

Requirements
Policy 1
- 1G 1.1 – Control Surveys (AIE Survey)

Policy 3
- 3A 4 – Interchange Transaction Implementation (Assessment)
- 3A 6 – Interchange Transaction Implementation (Implementation)
- 3B 4 – Interchange Schedule Implementation (Confirmation)
**Explanation**

The SCHEDULING AGENT would be the single point of contact for all external, non-participating CONTROL AREAS or other SCHEDULING AGENTS with respect to scheduling INTERCHANGE into, out of, or through the RTO. Intra-RTO TRANSACTIONS would be handled with the SCHEDULING AGENT acting as the single point of contact between each participating CONTROL AREA similar to an ADJACENT CONTROL AREA. This reduces the number of entities with which a given CONTROL AREA must coordinate, and should improve the management of INTERCHANGE TRANSACTIONS and INTERCHANGE SCHEDULES.

The RTO CONTROL AREA participants propose to:

1. Designate their RTO as a SCHEDULING AGENT to act on their behalf with all ADJACENT CONTROL AREAS with respect to implementation of INTERCHANGE SCHEDULES, including scheduling, confirmation and after-the-fact checkout.

2. Include the SCHEDULING AGENT in the SCHEDULING PATH of all INTERCHANGE TRANSACTIONS effectively placing the RTO SCHEDULING AGENT in the role of an INTERMEDIARY CONTROL AREA with respect to INTERCHANGE TRANSACTION management.

3. Manage any “scheduling error” attributable to the SCHEDULING AGENT and internalize this scheduling error into the INADVERTENT INTERCHANGE accounts of the participating CONTROL AREAS.

4. Include the SCHEDULING AGENT in the reporting of NET SCHEDULED INTERCHANGE in INADVERTENT INTERCHANGE reporting similar to an INTERMEDIARY CONTROL AREA.

By establishing a SCHEDULING AGENT function for the CONTROL AREAS under a multi-party regional agreement or transmission tariff, the following areas can be addressed and/or benefits achieved through the waiver approval:

1. NERC Policy 3B states that INTERCHANGE SCHEDULES shall only be implemented between ADJACENT CONTROL AREAS. Approval of the waiver will:
   a. Allow the participant RTO CONTROL AREAS to implement INTERCHANGE SCHEDULES directly with the SCHEDULING AGENT, significantly reducing the scheduling, coordination and checkout contacts of the participants.
   b. Allow CONTROL AREAS bordering a RTO to implement INTERCHANGE SCHEDULES with the SCHEDULING AGENT rather than the RTO participant CONTROL AREAS. For example, a CONTROL AREA interconnected with three CONTROL AREAS within a RTO under the SCHEDULING AGENT, would implement INTERCHANGE SCHEDULES with the SCHEDULING AGENT, rather than the three CONTROL AREAS, significantly reducing its scheduling, coordination and checkout contact requirements.

2. Seams issues associated with multiple CONTROL AREA scheduling paths existing between two adjacent RTOs are minimized by allowing the market to view the seam as a single interface between two RTOs, coordinated by their SCHEDULING AGENTS.

3. Rather than being faced with an ever-increasing number of ADJACENT CONTROL AREAS to implement INTERCHANGE SCHEDULES with and include in INADVERTENT Accounting, any CONTROL AREAS that implement INTERCHANGE SCHEDULES with the SCHEDULING AGENT remain unaffected as the RTO grows in Scope and Scale.
4. A RTO participant CONTROL AREA is only involved in the coordination of an INTERCHANGE SCHEDULE if it is the SOURCE or SINK CONTROL AREA in the INTERCHANGE TRANSACTION. For example, the CONTROL AREAS within a RTO would be transparent to the transmission customer as the customer reserves transmission service and submits an energy schedule for pass-through transactions across a RTO.

5. By simplifying the transaction implementation process for both participant and non-participant CONTROL AREAS, automation of INTERCHANGE confirmation, scheduling and checkout with the SCHEDULING AGENT becomes achievable.

The proposal simplifies the transaction tagging process for market participants in that there is no longer a need to designate a specific CONTROL AREA contract path within/through the RTO where there may, in fact, be several parallel contract paths possible. The specific scheduling processes implemented between participating CONTROL AREAS within the RTO are internalized and transparent to the market, but will not violate any reliability criteria.

**Current Operating Reliability**

There are no reliability implications from this waiver.
Policy Conditions for Waiver Recommendation

Policy 1F4.1

**INADVERTENT INTERCHANGE Accounting.** Adjacent CONTROL AREAS shall operate to a common NET INTERCHANGE SCHEDULE and ACTUAL NET INTERCHANGE value and shall record these hourly quantities, with like values but opposite sign. Each CONTROL AREA shall compute its INADVERTENT INTERCHANGE based on the following:

**Daily accounting.** Each CONTROL AREA, by the end of the next business day, shall agree with its adjacent CONTROL AREAS to the hourly integrated values of:

- **NET INTERCHANGE SCHEDULE**
- **NET ACTUAL INTERCHANGE**

**Conditions:**

The Control Area Participants shall designate their Scheduling Agent to be responsible for agreeing to NET INTERCHANGE SCHEDULE values with Adjacent Control Areas or other Scheduling Agents. The Control Areas will continue to calculate INADVERTENT INTERCHANGE based on Interchange Transactions sourcing and sinking in those Control Area.

Policy 1F4.2

**Monthly accounting.** Each CONTROL AREA shall use the agreed-to Daily accounting data to compile the monthly accumulated INADVERTENT INTERCHANGE for the On-Peak and Off-Peak hours of the month. [Refer to “Inadvertent Interchange Accounting Training Document”]

**Conditions:**

The Control Area Participants shall use, on a monthly basis, the NET INTERCHANGE SCHEDULES with their RTO Scheduling Agent in compiling Inadvertent Interchange reports. The RTO Scheduling Agent shall use all NET INTERCHANGE SCHEDULES with adjacent Control Areas or other Scheduling Agents.

Policy 1F6

**INADVERTENT INTERCHANGE summary.** Each CONTROL AREA shall submit a monthly summary of INADVERTENT INTERCHANGE as detailed in Appendix 1F, “INADVERTENT INTERCHANGE Energy Accounting Practices and Dispute Resolution Process.” These summaries shall not include any after-the-fact changes that were not agreed to by the SOURCE CONTROL AREA, SINK CONTROL AREA and all INTERMEDIARY CONTROL AREA(s).

**Conditions:**

The Control Area Participants shall continue to report NET ACTUAL INTERCHANGES with their physically interconnected Control Areas, but will report NET INTERCHANGE SCHEDULES only with their RTO Scheduling Agent. The RTO Scheduling Agent will report all NET INTERCHANGE SCHEDULES with adjacent Control Areas or other Scheduling Agents.
Policy Conditions

Policy 1G
**Surveys.** The CONTROL AREAS in each INTERCONNECTION shall perform each of the following surveys, as described in the Performance Standard Training Document, when called for by the Performance Subcommittee:

**AIE survey.** Area Interchange Error survey to determine the CONTROL Areas’ INTERCHANGE error(s) due to equipment failures or improper SCHEDULING operations, or improper AGC performance.

**Conditions:**
The Control Area Participants will allow the RTO Scheduling Agent to submit the AIE survey for Control Areas within the RTO’s boundary in a form similar to that proposed under Policy 1F.

Policy 3A4
The CONTROL AREA Assesses:
- Transaction start and end time
- Energy profile (ability of generation maneuverability to accommodate)
- Scheduling Path (proper connectivity of ADJACENT CONTROL AREAS)

**Conditions:**
The Control Area Participants will allow the RTO Scheduling Agent to assess proper connectivity on the Scheduling Path.

Policy 3A6
**Responsibility for INTERCHANGE TRANSACTION implementation.** The SINK CONTROL AREA is responsible for initiating the implementation of each INTERCHANGE TRANSACTION as tagged in accordance with Policy 3.A. Requirement 2 (and its subparts). The INTERCHANGE TRANSACTION is incorporated into the INTERCHANGE SCHEDULE(S) of all CONTROL AREAS on the SCHEDULING PATH in accordance with Policy 3B.

**Conditions:**
The applicants clarify that for pass-through transactions, the RTO Scheduling Agent shall assume the role and responsibilities of the INTERMEDIARY CONTROL AREA, and the individual RTO’s Control Areas do not appear in the Scheduling Path on the tag. The RTO’s Control Areas will not incorporate these transactions into a schedule in their EMS.
Policy 3B4

**INTERCHANGE SCHEDULE confirmation and implementation.** The **RECEIVING CONTROL AREA** is responsible for initiating the **CONFIRMATION** and **IMPLEMENTATION** of the **INTERCHANGE SCHEDULE** with the **SENDING CONTROL AREA**.

**INTERCHANGE SCHEDULE agreement.** The **SENDING CONTROL AREA** and **RECEIVING CONTROL AREA** shall agree with each other on the:

- Interchange Schedule start and end time
- Ramp start time and rate
- Energy profile

**Conditions:**

The obligation with respect to confirmation and implementation of **INTERCHANGE SCHEDULES** under Policy 3B4 shall be satisfied by the confirmation of all schedules with the Scheduling Agent. The Scheduling Agent shall assume the role and responsibilities that would otherwise be considered that of an **INTERMEDIARY CONTROL AREA** with respect to all transactions and schedules involving the RTO or its Control Areas.
Waiver Request – Financial Inadvertent Settlement

Organizations
The Control Area participants of:
- Alliance RTO
- Midwest ISO
- Southwest Power Pool

Operating Policy
The Control Area participants of the Alliance RTO, Midwest ISO and Southwest Power Pool are requesting a Waiver of specific provisions of NERC Policy 1, “Generation Control and Performance,” to allow financial settlement of INADVERTENT INTERCHANGE within a RTO. The Midwest ISO has filed with the FERC Service Schedule 4 – Energy Imbalance, which contains a provision for financial settlement of INADVERTENT INTERCHANGE between the Midwest ISO CONTROL AREAS.

The RTO Organizations request a waiver from Policy 1, Section F:

5.2. Other payback methods. Upon agreement by all Regions within an INTERCONNECTION, other methods of INADVERTENT payback may be utilized.

Explanation
The participant Control Areas ask for a waiver from the requirement that the method of INADVERTENT payback within the RTO be agreed upon by all Regions within the Eastern INTERCONNECTION. Approval of this waiver would allow the participant Control Areas to adjust their hourly INADVERTENT through an RTO financial settlement process while assuring that the method of INADVERTENT payback will not affect non-participant Control Areas or the net INADVERTENT owed to the INTERCONNECTION. For reliability reporting, such as for the NERC Area Interchange Error (AIE) report, the participant Control Areas will continue to report the actual “on-peak” and “off-peak” INADVERTENT INTERCHANGE incurred in all hours. In addition, they will also maintain an adjusted INADVERTENT account to reflect the amount owed to the INTERCONNECTION after financial settlement within the RTO.

Under the financial settlement process, the RTO will determine the amount of INADVERTENT INTERCHANGE that can be financially settled between the Control Areas within the RTO while assuring that the net INADVERTENT INTERCHANGE for the combined CONTROL AREAS under the RTO will not change.
The example below and to the right reflects five CONTROL AREAS within a RTO. Before financial settlement of INADVERTENT INTERCHANGE the net of the five CONTROL AREAS’ INADVERTENT INTERCHANGE is 30 MWh. As the net INADVERTENT for the hour is positive, all negative INADVERTENT is financially settled within the RTO with 30 MWh remaining to be reported by the CONTROL AREAS post-settlement. Through this process the INADVERTENT INTERCHANGE account with the INTERCONNECTION is unaffected.

<table>
<thead>
<tr>
<th>Control Area</th>
<th>Inadvertent</th>
<th>Settlement Schedule*</th>
<th>Adjusted Inadvertent</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>-20</td>
<td>-20</td>
<td>0</td>
</tr>
<tr>
<td>B</td>
<td>15</td>
<td>10</td>
<td>5</td>
</tr>
<tr>
<td>C</td>
<td>-75</td>
<td>-75</td>
<td>0</td>
</tr>
<tr>
<td>D</td>
<td>45</td>
<td>35</td>
<td>10</td>
</tr>
<tr>
<td>E</td>
<td>65</td>
<td>50</td>
<td>15</td>
</tr>
<tr>
<td><strong>RTO Net</strong></td>
<td><strong>30</strong></td>
<td><strong>0</strong></td>
<td><strong>30</strong></td>
</tr>
</tbody>
</table>

* MWh settled financially

**Current Operating Reliability**

There are no reliability implications from this waiver.
Policy 1F5.2

**Other payback methods.** Upon agreement by all REGIONS within an INTERCONNECTION, other methods of INADVERTENT payback may be utilized.

<table>
<thead>
<tr>
<th>Conditions:</th>
</tr>
</thead>
<tbody>
<tr>
<td>The Control Area Participants within the scope of the RTO that financially settle inadvertent will report both the unadjusted and adjusted quantities on the Inadvertent Interchange summary.</td>
</tr>
</tbody>
</table>
Waiver Request – Control Performance Standard 2

**Organization**
ERCOT

**Operating Policy**
ERCOT requests a waiver from Policy 1, “Generation Control and Performance,” Section E, “Performance Standard” as follows:

**Standards**
1.2. **Control Performance Standard (CPS2).** The average ACE for each of the six ten-minute periods during the hour (i.e., for the ten-minute periods ending at 10, 20, 30, 40, 50, and 60 minutes past the hour) must be within specific limits, referred to as $L_{10}$. See the “Performance Standard Training Document,” Section B.1.1.2 for the methods for calculating $L_{10}$.

**Requirements**
2. **Control Performance Standard (CPS) Compliance.** Each CONTROL AREA shall achieve CPS1 compliance of 100% and achieve CPS2 compliance of 90% (see the “Performance Standard Training Document,” Section C).

**Explanation**
ERCOT requests a waiver from the CPS2 Standards and Requirements listed above for the following reasons:

1. On July 31, 2001, the ERCOT Interconnection began operating as a single CONTROL AREA, asynchronously connected via two DC ties to the Eastern Interconnection. At that time, ERCOT changed from the traditional tie-line bias generation control algorithms in which ten CONTROL AREAS participated, to a single 15-minute interval competitive balancing energy market and a frequency control system that regulates around the balancing energy schedule on two-to-four-second intervals. ERCOT requests that the Operating Committee reconsider CPS2 to ensure it is feasible under this new type of market-based control.

If the Operating Committee believes that the CPS2 is feasible, then ERCOT would suggest that Policy 1 (or the appropriate Compliance document) provide for a “test period” of six months to allow CONTROL AREAS making such a transition the opportunity to test new control algorithms provided they can show that reliability is not degraded during that period. ERCOT also believes that its $L_{10}$ may not be appropriate as it is less than half of the $L_{10}$ of another NERC CONTROL AREA of similar load size.

2. The ERCOT Interconnection is now a single CONTROL AREA asynchronously connected to the Eastern Interconnection, and cannot create inadvertent power flows or frequency errors in other CONTROL AREAS. Therefore, the ISO questions whether the CPS2 Standard is necessary or even beneficial for such asynchronous operation. ERCOT is currently performing a study that compares its single CONTROL AREA performance against that of the former ten CONTROL AREA
operations. Initial results of that study show that while the ten CONTROL AREAS individually met CPS2 standards, the aggregate CPS2 performance of the ten CONTROL AREAS did not, and was actually below that of the current single CONTROL AREA.

**Current Operating Reliability**

ERCOT does not believe that Frequency control within its new single CONTROL AREA INTERCONNECTION is less reliable as a result of non-compliance with the CPS2 Standard following its conversion. ERCOT Interconnection frequency control has been, and continues to be, very reliable since that conversion.

The table below shows ERCOT’s CPS2 performance for August through December 2000 as an INTERCONNECTION with ten Control Areas. The average CPS2 compliance was 74.82%. CPS2 compliance for ERCOT as a single control area for August 2001 was 83.88%, an improvement of approximately nine percentage points.

### Single Control Area Frequency Performance

<table>
<thead>
<tr>
<th>% of Frequency Data Available</th>
<th>Supplier Of Frequency Data</th>
<th>Single Control Area CPS1 %</th>
<th>CPS2 %</th>
<th>Average of Absolute 1 min Averages Freq Deviation</th>
<th>Average of Absolute 10 min Averages Freq Deviation</th>
</tr>
</thead>
<tbody>
<tr>
<td>August-00</td>
<td>79</td>
<td>ERCOT</td>
<td>140.99</td>
<td>76.50</td>
<td>0.011978483</td>
</tr>
<tr>
<td>September-00</td>
<td>100</td>
<td>ERCOT</td>
<td>134.89</td>
<td>76.02</td>
<td>0.012366</td>
</tr>
<tr>
<td>September-00</td>
<td>100</td>
<td>REIT HLP</td>
<td>135.91</td>
<td>77.01</td>
<td>0.012221795</td>
</tr>
<tr>
<td>October-00</td>
<td>23</td>
<td>ERCOT</td>
<td>199.68</td>
<td>76.90</td>
<td>0.013910426</td>
</tr>
<tr>
<td>October-00</td>
<td>100</td>
<td>REIT HLP</td>
<td>114.01</td>
<td>78.58</td>
<td>0.014621429</td>
</tr>
<tr>
<td>November-00</td>
<td>65</td>
<td>ERCOT</td>
<td>105.19</td>
<td>67.20</td>
<td>0.015061531</td>
</tr>
<tr>
<td>December-00</td>
<td>60</td>
<td>ERCOT</td>
<td>192.59</td>
<td>72.60</td>
<td>0.013428052</td>
</tr>
<tr>
<td>Average (See Note 1)</td>
<td></td>
<td></td>
<td>134.71</td>
<td>74.82</td>
<td>0.013439915</td>
</tr>
<tr>
<td>August-01</td>
<td>None (See Note 2)</td>
<td>None (See Note 2)</td>
<td>127.30</td>
<td>83.88</td>
<td></td>
</tr>
</tbody>
</table>

Note 1: Weighted Average Based on ERCOT for August, September November and December and REIT for October.  
Note 2: From ERCOT CPS report. ERCOT is working on providing frequency data for August 2001.
Waiver Request – Tagging Dynamic Schedules and Inadvertent Payback

**Entity**  
Western Electricity Coordinating Council – Operating Committee

**Policy**  
Policy 3 “Interchange”

**Waiver Requested**  
Add the following to third bullet under Policy 3 Section A.2.1 – Deference to the WECC where Dynamic Interchange Schedules are of known amounts by the sending and receiving control areas, have existing transmission capacity, and the Transmission Providers are aware of the amounts which are exempt from being tagged.

Add the following to the fourth bullet under Policy 3 Section A.2.1 – Deference to the WECC where existing procedure require notification of bilateral payback to be made via the WECC Messaging network where all parties are notified. Amounts less than or equal to 25 megawatts per hour are not required to be tagged.

**Explanation**  
The WECC Operating Committee and Interchange Scheduling and Accounting Subcommittee requested a waiver to Policy 3 to tagging requirements for bilateral inadvertent interchange payback schedules and dynamic schedules.  
The tagging requirements simply do not apply to operations in the Western Interconnection.  
Adding a tagging requirement for dynamic schedules will add a burden on scheduling entities and will not provide a substantial benefit.  CA and TP have real-time scheduling information on dynamic schedules.

Unilateral inadvertent payback is not allowed in the WECC.
Waiver Request – Energy Flow Information

Organization
The Control Area participants of:
- Midwest ISO

Operating Policy
The CONTROL AREA participants request approval of this Waiver to implement a proposed multi-Control Area Energy Market, simplify TRANSACTION information requirements for market participants, and provide a means for providing Reliability Coordinators with appropriate information for reliability analysis, curtailments, relocations, and Network and Native Load (NNL) redispach requirements.

The participants are requesting a Waiver of specific provisions of NERC Policy 3, “Interchange,” to accommodate a Multi-Control Area Energy Market. This waiver would also apply in the event that Control Areas in the RTO are combined into fewer Control Areas or into one Control Area. This wavier is required to realize the benefits of a LMP market operation in the RTO Area while increasing the level of granularity of information provided to the NERC Transmission Loading Relief Process. It is understood that the level of granularity of information provided to Reliability Coordinators must not be reduced or reliability will be negatively impacted. The RTO participants propose the use of the concepts contained within the PJM/MISO paper, “Managing Congestion to Address Seams,” to meet the requirements specified in Policy 3.

The following specific sections of NERC Policy 3, Version 5.1, “Interchange,” are affected by the RTO Scheduling Process proposed in this Waiver request:

Requirements
Policy 3
- 3A 2.1 – Application to Transactions

Explanation
Policy 3 currently requires that several different types of transactions be tagged; specifically, it requires that any transactions involving Control Area to Control Area transfers must be tagged in order that Reliability Coordinators may review them as necessary to ensure system reliability.

The Midwest ISO intends to begin operating a multi-Control Area Energy Market in the near future. In so doing, the Midwest ISO will be scheduling net energy transfers between their various Control Area members based on a dynamically calculated, security-constrained economic dispatch. Bilateral transactions and transactions into or out of the RTO will continue to be tagged as appropriate. Net Control Area interchanges resulting from the market dispatch will simultaneously sum to zero within the MISO market. These market dispatch instructions do not correspond to traditional bilateral transactions between Control Areas. Instead, they can be viewed as a method to economically dispatch all generation within the Midwest ISO market. Each Control Area’s net interchange resulting from market dispatch is matched simultaneous with all the other Control Areas in the market. Rather than a specific Control Area assigned to receive this net market interchange, all Control Areas net interchanges in the market will be adjusted to sum to zero. Tagging this market interchange into bilateral transactions would be arbitrary and not
accurate. Therefore, the Midwest ISO proposes that rather than supply Reliability Coordinators with tags, they instead be allowed to provide Reliability Coordinators with equivalent information that allows the same analyses and procedures to operate as would exist if tags had been entered.

Under this proposal, the Midwest ISO will establish a set of Coordinated Flowgates, which will be determined through the use of several studies, that represents all flowgates significantly impacted by the Midwest ISO’s operation of their Energy Market. Further, the Midwest ISO will provide Reliability Coordinators the following information every 15 minutes:

- Total Flows attributed to Midwest ISO market operations for all Coordinated Flowgates
- Flows attributed to Midwest ISO NNL for all Coordinated Flowgates
- Flows attributed to Midwest ISO Economic Dispatch for all Coordinated Flowgates

This information will be provided for both current hour and next hour, and will be used to communicate to Reliability Coordinators the amount of flows to be considered as the result of firm and non-firm service on the various Coordinated Flowgates.

Additionally, every hour the Midwest ISO will submit to Reliability Coordinators a set of data describing the marginal units and associated participation factors for generation within the Midwest ISO market footprint. This data will at a minimum be supplied for imports to and exports from the market area, and will contain as much information as is determined to be necessary to ensure system reliability. This data will be used by Reliability Coordinators to determine the impacts of schedule curtailment requests when they result in a shift in the dispatch within the market area.

Finally, the Midwest ISO will submit for each of its Control Areas estimated Interchange and Load for each hour of the day. This will be submitted on a day ahead basis as well as an hour ahead basis. This data will be used by Reliability Coordinators to perform forward-looking security analyses.

Current Operating Reliability Implications

There are no reliability implications from this waiver.
Policy 3A.2.1

**Application to TRANSACTIONS.** All INTERCHANGE TRANSACTIONS and certain INTERCHANGE SCHEDULES shall be tagged. In addition, intra-CONTROL AREA transfers using Point-to-Point Transmission Service\(^1\) shall be tagged. This includes:

- INTERCHANGE TRANSACTIONS (those that are between CONTROL AREAS).
- TRANSACTIONS that are entirely within a CONTROL AREA.
- DYNAMIC INTERCHANGE SCHEDULES (tagged at the expected average MW profile for each hour). (Note: a change in the hourly energy profile of 25% or more requires a revised tag.)
- INTERCHANGE TRANSACTIONS for bilateral INADVERTENT INTERCHANGE payback (tagged by the SINK CONTROL AREA).
- INTERCHANGE TRANSACTIONS established to replace unexpected generation loss, such as through prearranged reserve sharing agreements or other arrangements, are exempt from tagging for 60 minutes from the time at which the INTERCHANGE TRANSACTION begins (tagged by the SINK CONTROL AREA). [*See also, Policy 1E2 and 2.1, “Disturbance Control Standard”*]

**Conditions:**

The Midwest ISO must provide equivalent information regarding their market operations to Reliability Authorities as would be extracted from a transaction tag. Specifically, the Midwest ISO must provide:

1.) Flows on significantly impacted flowgates, with indications as to firmness of those flows, in order that curtailments, reload, and reallocations may be directed by Reliability Coordinators as needed.

2.) Marginal Units within the market footprint, in order that Reliability Coordinators may evaluate impacts of potential changes in dispatch within the market footprint.

3.) Control Area Interchange and Load forecasts, in order that Reliability Coordinators may analyze the interconnected transmission system on a proactive basis.

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\(^1\) This includes all “grandfathered” and other “non-888” Point-to-Point Transmission Service
Waiver Request – Enhanced Congestion Management
(Curtailment/Reload/Reallocation)

Organization

The control area participants of:

- Midwest ISO, Inc.
- PJM Interconnection, L.L.C.

Operating Policy

The control area participants request approval of this waiver to implement a proposed multi-control area energy market, simplify transaction information requirements for market participants, and provide a means for providing Reliability Coordinators with appropriate information for security analysis and curtailments/reloads/reallocations and redispatch requirements.

The participants are requesting a waiver of specific provisions of the following NERC policies and appendices to accommodate a Multi-Control Area Energy Market.

This waiver would also apply in the event that applicant control areas are combined into fewer control areas or into one control area. This waiver is required to realize the benefits of a LMP market operation while increasing the level of granularity of information provided to the NERC Transmission Loading Relief Procedure. The applicant control areas propose the use of the concepts contained within the PJM/MISO paper, “Managing Congestion to Address Seams,” to meet the requirements specified in Policy 9 and its related appendixes.

The processes proposed in this waiver request affect the following specific sections of NERC Policy 9:

- Appendix 9C1B.C (How the IDC Handles Reallocation),
- Appendix 9C1B.C Attachment B – Timing Requirements (IDC Calculations and Reporting Requirements), and
- Appendix 9C1.G (Transaction Curtailment Formula)
- Appendix 9C1B “Interchange Transaction Reallocation During TLR Levels 3a and 5a”

For the purposes of clarity, this waiver describes many actions as those of the “RTO.” It should be noted that “RTO” refers to the market-operating entity in which the applicant control areas participate. Associated with this waiver are two distinct entities: 1.) Midwest ISO, and 2.) PJM Interconnection.
Assignment of Sub-Priorities

Requirements
Policy 9 – Appendix 9C1B

- 9C1B.C
- 9C1B.C.Attachment B

Explanation

The “IDC Calculations and Reporting Requirements” section of Appendix 9C1B.C, Attachment B – Timing Requirements of Policy 9 states that “In a TLR Level 3a the INTERCHANGE TRANSACTIONS using Non-firm Transmission Service in a given priority will be further divided into four sub-priorities, based on current schedule, current active schedule (identified by the submittal of a tag ADJUST message), next-hour schedule, and tag status.”

The RTO intends to use a “Market Flow Calculation” methodology to calculate the amount of energy flowing across all facilities included in the RTO’s “Coordinated Flowgate List”1 that is associated with the operation of the RTO market. This energy is identified as “market flow”.

These market flow impacts for current hour and next hour will be separated into their appropriate priorities2 and provided to the IDC by the RTO. The market flows will then be represented and made available for curtailment under the appropriate TLR Levels.

Even though these market flow impacts (separated into appropriate priorities) will not be represented by conventional “tags”, the impacts and their desired levels will still be provided to the IDC for current hour and next hour. Therefore, the RTO proposes that for the purposes of reallocation, a sub-priority (S1 thru S4) be assigned to these market flow impacts by the NERC IDC, using the same parameters as would be used if the impacts were in fact tagged transactions — as detailed in NERC Policy 9, Appendix 9C1, Attachment B – Timing Requirements (IDC Calculations & Reporting Requirements). See Example 1 Below

---

1 The RTO will conduct sensitivity studies to determine which external flowgates (outside the RTO’s footprint) are significantly impacted by the market flows of the RTO’s control zones (currently the control areas that exist today in the IDC). The RTO will perform the 4 studies (described in the MISO/PJM Paper “Managing Congestion to Address Seams” White Paper Version 3.2) to determine which external flowgates the RTO will monitor and help control. An external flowgate selected by one of these studies will be considered a Coordinated Flowgate (CF).

2 See the PJM/MISO Paper “Managing Congestion to Address Seams” for details on how these priorities will be assigned
### EXAMPLE 1

**Appropriate Sub-Priority**

<table>
<thead>
<tr>
<th></th>
<th>“S1”</th>
<th>“S2”</th>
<th>“S3”</th>
<th>“S4”</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Tags Today</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Curr Hr</td>
<td>Desired</td>
<td>Next Hr</td>
<td>Start Next</td>
<td></td>
</tr>
<tr>
<td>90</td>
<td>100</td>
<td>110</td>
<td>160</td>
<td></td>
</tr>
</tbody>
</table>

**Market Impacts to be Submitted by RTO**

<table>
<thead>
<tr>
<th></th>
<th>Curr Hr</th>
<th>Desired</th>
<th>Next Hr</th>
<th>Start Next</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
**Pro Rata Curtailment of Non-Firm Market Flow Impacts**

**Requirements**
- Appendix 9C1.G (Transaction Curtailment Formula)

**Explanation**

NERC Policy 9, Appendix 9C1.G (Transaction Curtailment Formula) details the formula used to apply a weighted impact to each non-firm tagged transaction (Priorities 1 thru 6) for the purposes of curtailment by the IDC. For the purpose of curtailment, we propose that the non-firm market flow impacts (Priorities 1 thru 6) submitted to the IDC by the RTO be curtailed pro rata as is done for INTERCHANGE TRANSACTIONS using firm transmission service. This is because several of the values needed to assign a weighted impact using the process listed in Policy 9 Appendix 9C1.G (Transaction Curtailment Formula) will not be available:

- Distribution Factor (no tag to calculate this value from)
- Impact on Interface value (cannot be calculated without Distribution Factor)
- Impact Weighting Factor (cannot be calculated without Distribution Factor)
- Weighted Maximum Interface Reduction (cannot be calculated without Distribution Factor)
- Interface Reduction (cannot be calculated without Distribution Factor)
- Transaction Reduction (cannot be calculated without Distribution Factor)

While the non-firm market flow impacts submitted to the IDC would be curtailed pro rata under this proposal, the impacting non-firm tagged transactions could still use the existing processes to assign the weighted impact value. “Example 2” (below) illustrates how this would be accomplished.
NNL Calculation

Requirements

- Appendix 9C1.F (Parallel Flow Calculation Procedure for Reallocating or Curtailing Firm Transmission Service)

- Parallel Flow Calculation Procedure Reference Document – Section C (Calculation Method)

Explanation

Policy 9 – Appendix 9C1.F and the Parallel Flow Calculation Procedure Reference Document – Section C currently require that the “Per Generator Method Without Counter Flow” methodology be utilized to calculate the portion of parallel flows on any Constrained Facility due to Network Integration (NI) transmission service and service to Native Load (NL) of each control area.

The RTO intends to use a “Market Flow Calculation” methodology to calculate the portion of parallel flows on all facilities included in the RTO’s “Coordinated Flowgate List” due to NI service or service to NL of each control area.

---

3 The RTO will conduct sensitivity studies to determine which external flowgates (outside the RTO’s footprint) are significantly impacted by the market flows of the RTO’s control zones (currently the control areas that exist today in the IDC). The RTO will perform the four studies (described in the MISO/PJM paper “Managing Congestion to Address Seams,” Version 3.2) to
The Market Flow Calculation differs from the Per Generator Method in the following ways:

- The contribution from all market area generators will be taken into account.

- In the Per Generator Method, only generators having a GLDF greater than 5% are included in the calculation. Additionally, generators are included only when the sum of the maximum generating capacity at a bus is greater than 20 MW. The market flow calculations will use all positively impacting flows down to 0% with no threshold. Counter flows will not be included in the market flow calculation.

- The contribution of all market area generators is based on the present output level of each individual unit.

- The contribution of the market area load is based on the present demand at each individual bus.

By expanding on the Per Generator Method, the market flow calculation evolves into a methodology very similar the “Per Generator Method” method, while providing granularity on the order of the most granular method developed by the IDC Granularity Task Force. Counter flows are also calculated and tracked in order to account for and recognize that the either the positive market flows may be reduced or counter flows may be increased to provide appropriate relief on a flowgate. Under this proposal, the use of real-time values in concert with the market flow calculation effectively implements the most accurate and detailed method of the six IDC granularity options considered by the NERC IDC Granularity Task Force.

Units assigned to serve a market area’s load do not need to reside within the RTO’s market area footprint to be considered in the market flow calculation. However, units outside of the RTO’s market area will not be considered when those units will have tags associated with their transfers.

These NNL values will be provided to the IDC to be included and represented with the calculated NNL values of all non-RTO control areas for the purposes identifying and obtaining required NNL relief across a flowgate in congestion under a TLR Level 5A/5B.

5% Curtailment Threshold

Requirements

- Appendix 9C1B – Item A.2
Explanation

Policy 9 – Appendix 9C1B – Item A.2 states that “Only those INTERCHANGE TRANSACTIONS at or above the Curtailment Threshold for which a TLR 2 or higher is called are affected by the Reallocation procedure.” The curtailment threshold stated in this section is “5%”.

The RTO intends to use a “Market Flow Calculation” methodology to calculate the amount of energy flowing across all facilities included in the RTO’s “Coordinated Flowgate List” that is associated with the operation of the RTO Market. This energy is identified as “Market Flow.”

The RTO intends to provide to the IDC any market flows with an impact of greater than 0% on a coordinated flowgate. These market flows will then be represented and made available for curtailment under the appropriate TLR Levels. Hence, for the purposes of curtailment and reallocation, the RTO proposes that the impact threshold the RTO will observe for its market flows across any flowgate in the RTO Coordinated Flowgate List will be 0% instead of 5%.

The reason for this is that because of the size and scope of a large non-tagged energy market, such as the multi-control area market that the RTO is proposing, an impact of less than 5% on a flowgate could still represent a large amount of the total capacity of that flowgate. Therefore, to limit the Curtailment Threshold on these market flows to 5% could result in a Reliability Coordinator’s inability to obtain the amount of relief that is needed to prevent the flowgate from exceeding its operating limits.

Below is an example of how a market flow curtailment threshold of less than 5% could substantially contribute to congestion on a flowgate:

Example:

- Energy market flows of 1,000 MW impact Flowgate A by 4% — or 40 MW
- Flowgate A operating limit is 100 MW
- Fully 40% of the flow across Flowgate A is not identified and represented in the IDC, and therefore not available for curtailment under the TLR process.

Current Operating Reliability

There are no reliability implications from this waiver.

---

4 The RTO will conduct sensitivity studies to determine which external flowgates (outside the RTO’s footprint) are significantly impacted by the market flows of the RTO’s control zones (currently the control areas that exist today in the IDC). The RTO will perform the 4 studies (described in the MISO/PJM “Managing Congestion to Address Seams” Whitepaper Version 3.2) to determine which external flowgates the RTO will monitor and help control. An external flowgate selected by one of these studies will be considered a Coordinated Flowgate (CF).
Waiver Request – Enhanced Scheduling Agent

Organization
The Control Area participants of:

- Midwest ISO

Operating Policy
The CONTROL AREA participants request approval of this Waiver to implement a proposed RTO Scheduling Process to meet the RTO obligations under Order 2000, simplify TRANSACTION information requirements for market participants, reduce the number of parties with which CONTROL AREA operators must communicate, and provide a common means to tag TRANSACTIONS within and between RTOs.

The participants are requesting a Waiver of specific provisions of NERC Policy 3, “Interchange,” to accommodate a RTO Scheduling Process. The RTO participants propose the following definition of a ENHANCED SCHEDULING AGENT:

ENHANCED SCHEDULING AGENT. A function with the authority to act on behalf of one or more CONTROL AREAS for INTERCHANGE SCHEDULE implementation including creation, confirmation, approval, check-out and associated INADVERTENT INTERCHANGE accounting.

The following specific sections of NERC Policy 3, Version 4, “Interchange,” are affected by the RTO Scheduling Process proposed in this Waiver request:

Policy 3

- 3A 4 – Interchange Transaction Implementation (Assessment)
- 3A 6 – Interchange Transaction Implementation (Implementation)
- 3B 4 – Interchange Schedule Implementation (Confirmation)

Explanation
The ENHANCED SCHEDULING AGENT would be the single point of contact for all external, non-participating CONTROL AREAS or other SCHEDULING AGENTS with respect to scheduling INTERCHANGE into, out of, or through the RTO. Through TRANSACTIONS would be handled with the ENHANCED SCHEDULING AGENT acting as the single point of contact between each participating CONTROL AREA similar to an ADJACENT CONTROL AREA. Into or Out Of TRANSACTIONS would be handled with the ENHANCED SCHEDULING AGENT acting as the SINK or SOURCE CONTROL AREA, respectively. This reduces the number of entities with which a given CONTROL AREA must coordinate, and should improve the management of INTERCHANGE TRANSACTIONS and INTERCHANGE SCHEDULES.

The RTO CONTROL AREA participants propose to:

1. Designate their RTO as a ENHANCED SCHEDULING AGENT to act on their behalf with all external ADJACENT CONTROL AREAS with respect to implementation of INTERCHANGE SCHEDULES, including scheduling, confirmation and after-the-fact checkout.
2. Include the Enhanced Scheduling Agent in the Scheduling Path of all Interchange Transactions in the role of Control Area (Intermediary, Source, or Sink as appropriate) with respect to Interchange Transaction management.

3. Include the ENHANCED SCHEDULING AGENT in the reporting of NET SCHEDULED INTERCHANGE in INADVERTENT INTERCHANGE reporting similar to a CONTROL AREA.

By establishing a ENHANCED SCHEDULING AGENT function for the CONTROL AREAS under a multi-party regional agreement or transmission tariff, the following areas can be addressed and/or benefits achieved through the waiver approval:

1. NERC Policy 3B states that INTERCHANGE SCHEDULES shall only be implemented between ADJACENT CONTROL AREAS. Approval of the waiver will allow CONTROL AREAS bordering a RTO to implement INTERCHANGE SCHEDULES with the ENHANCED SCHEDULING AGENT rather than the RTO participant CONTROL AREAS. For example, a CONTROL AREA interconnected with three CONTROL AREAS within a RTO under the ENHANCED SCHEDULING AGENT, would implement INTERCHANGE SCHEDULES with the ENHANCED SCHEDULING AGENT, rather than the three CONTROL AREAS, significantly reducing its scheduling, coordination and checkout contact requirements.

2. Seams issues associated with multiple CONTROL AREA scheduling paths existing between two adjacent RTOs are minimized by allowing the market to view the seam as a single interface between two RTOs, coordinated by their SCHEDULING AGENTS.

3. Rather than being faced with an ever-increasing number of ADJACENT CONTROL AREAS to implement INTERCHANGE SCHEDULES with and include in INADVERTENT Accounting, any CONTROL AREAS that implement INTERCHANGE SCHEDULES with the ENHANCED SCHEDULING AGENT remain unaffected as the RTO grows in Scope and Scale.

4. The CONTROL AREAS within a RTO served by a ENHANCED SCHEDULING AGENT would be transparent to a transmission customer as the customer reserves transmission service and submits an energy schedule for pass-through transactions across said RTO.

5. By simplifying the transaction implementation process for both participant and non-participant CONTROL AREAS, automation of INTERCHANGE confirmation, scheduling and checkout with the ENHANCED SCHEDULING AGENT becomes achievable.

The proposal simplifies the transaction tagging process for market participants in that there is no longer a need to designate a specific CONTROL AREA contract path within or through the RTO where there may, in fact, be several parallel contract paths possible. The specific scheduling processes implemented between participating CONTROL AREAS within the RTO are internalized and transparent to the market, but will not violate any reliability criteria.

**Current Operating Reliability Implications**

There are no reliability implications from this waiver.
Policy Conditions for Waiver Recommendation

Policy 3A4
The CONTROL AREA Assesses:

- Transaction start and end time
- Energy profile (ability of generation maneuverability to accommodate)
- Scheduling Path (proper connectivity of ADJACENT CONTROL AREAS)

Conditions:
The Control Area Participants will allow the RTO Scheduling Agent to assess proper connectivity on the Scheduling Path.

Policy 3A6
Responsibility for INTERCHANGE TRANSACTION implementation. The SINK CONTROL AREA is responsible for initiating the implementation of each INTERCHANGE TRANSACTION as tagged in accordance with Policy 3.A. Requirement 2 (and its subparts). The INTERCHANGE TRANSACTION is incorporated into the INTERCHANGE SCHEDULE(S) of all CONTROL AREAS on the SCHEDULING PATH in accordance with Policy 3B.

Conditions:
The applicants clarify that the Enhanced Scheduling Agent shall assume the role and responsibilities of the INTERMEDIARY, SOURCE, or SINK CONTROL AREA as appropriate with regard to Policy 3, and the individual RTO's Control Areas do not appear in the Scheduling Path on the tag. The RTO's Control Areas will not incorporate these transactions into a schedule in their EMS.

Approved by Operating Committee:
July 16, 2003
Policy 3B4

**INTERCHANGE SCHEDULE confirmation and implementation.** The RECEIVING CONTROL AREA is responsible for initiating the CONFIRMATION and IMPLEMENTATION of the INTERCHANGE SCHEDULE with the SENDING CONTROL AREA.

**INTERCHANGE SCHEDULE agreement.** The SENDING CONTROL AREA and RECEIVING CONTROL AREA shall agree with each other on the:

- Interchange Schedule start and end time
- Ramp start time and rate
- Energy profile

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**Conditions:**

The obligation with respect to confirmation and implementation of INTERCHANGE SCHEDULES under Policy 3B 4 shall be satisfied by the confirmation of all schedules with the Scheduling Agent. The Scheduling Agent shall assume the role and responsibilities that would otherwise be considered that of an INTERMEDIARY, SOURCE, or SINK CONTROL AREA as appropriate with respect to all transactions and schedules involving the RTO or its Control Areas.

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**Additional Conditions**

The Operating Committee approved this waiver on July 16, 2003 with the following condition:

“With NERC and appropriate regional representation, audit and confirm the Midwest ISO’s readiness to perform the functions detailed in the enhanced scheduling agent and energy flow information waivers before they go into effect.”
Waiver Request – Western Interconnection
Thresholds to Initiate Manual Corrections for Time Error

Organizations
The Control Area participants of:

- Western Interconnection, viz., the Western Electricity Coordinating Council (WECC)

Operating Policy
The CONTROL AREA participants Western Interconnection are requesting a Waiver, on a trial basis, to set new thresholds for initiating manual corrections for time error excursions. Specifically, this involves Appendix 1D of NERC Policy 1, “Generation Control and Performance.”

The WECC requests, on a trial basis, a Waiver from Policy 1, Appendix 1D to alter the thresholds for initiating manual corrections for time error excursions from ±2 seconds to −5 seconds and +7 seconds.

Standard
1. Time error correction notice and commencement. Time error corrections shall be conducted in accordance with Appendix 1D, “Time Error Correction Procedure.”

Explanation
The WECC has taken bold steps in technology to automatically reduce time error accumulations and, simultaneously, eliminate primary Inadvertent Interchange. This is a new technology and is still in the development stage. Recent analysis, first viewed on July 23, revealed apparent “natural cyclical variations” in time error of ±7 seconds. After consideration, the WECC Performance Work Group chose thresholds of −5 seconds and +7 seconds to initiate manual corrections, which covers about 85% of the variation.

Current Operating Reliability Implications
There are no reliability implications from this waiver.

Policy Conditions for Waiver Recommendation
None.
Appendix 1D – Time Error Correction Procedures

DRAFT Version 2.A

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<tr>
<td>Fast</td>
<td>+10</td>
<td>+7</td>
<td>+3</td>
</tr>
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Notes:

For the Eastern Interconnection:

1. No corrections for fast time will be initiated between 0400–1100 Central Time.
2. Corrections begin on the hour or half-hour.
3. Corrections shall last at least one hour, unless there is a cause for termination.

For all Interconnections:

1. A time correction may be halted, terminated, or extended if the designated Interconnection Time Monitor determines system conditions warrant such action.
2. After the premature termination of a manual time correction, a slow time correction can be reinstated after the frequency has returned to 60 Hz or above for a period of ten minutes. A fast time correction can be reinitiated after the frequency has returned to 60 Hz or lower for a period of ten minutes. At least one hour shall elapse, however, between the termination and re-initiation notices.
Waiver Request – RTO Inadvertent Interchange Accounting

**Organization**
The control area participants of the Midwest ISO

**Operating Policy**

Standards
Policy 1F, Inadvertent Interchange Standard

Requirements
Policy 1G 1.1. – Control Surveys (AIE Survey)
Policy 1G2.2. – Inadvertent Interchange Summaries (Surveys)

**Explanation**
NERC Policy 1.F “Inadvertent Interchange Standard” speaks only of control areas accounting for Inadvertent Interchange. The policy was written before the advent of RTOs.

The **CONTROL AREA participants request that the RTO be given an Inadvertent Interchange account.** This will support the RTO in meeting its FERC-directed market obligations.

The current model for an LMP market requires financial settlement of all energy receipts and deliveries. This means control areas operating within this market will pay for (or be paid for) their Inadvertent Interchange. Financial settlement of inadvertent is allowed under Policy 1.F. 5.2. (other payback methods) and the **Financial Inadvertent Settlement Waiver.**

The approved **Enhanced Scheduling Agent Waiver** authorizes the RTO to act as a sink or source Control Area in order to manage transactions into, out of, or through the RTO. Approval of this **Inadvertent Interchange Waiver** allows the RTO to manage any financially settled net imbalance with the Interconnection.

**Continued Responsibilities**
Control areas will continue to perform all the traditional Inadvertent Accounting tasks as outlined in NERC Policy 1.F. and Appendix 1.F. In other words, the RTO control areas will continue to:

- Verify daily Actual Net Interchange with their adjacent control areas and if there are differences, resolve them within the time frame in NERC Policy 1.F.
- Operate to “equal and opposite” Net Actual Interchange with their adjacent control areas.
- Operate to an “equal and opposite” Scheduled Net Interchange with the RTO, consistent with the current **Scheduling Agent Waiver.**
Policy Conditions

- Verify daily Scheduled Net Interchange with the RTO and if there are differences, resolve them within the time frame in NERC Policy 1.F.

- Report their monthly Inadvertent Interchange data to their respective Regions.

The RTO will also continue to perform all the Inadvertent Accounting tasks as an intermediate control area (as specified in the Scheduling Agent Waiver) and source or sink control area (as specified in the Enhanced Scheduling Agent Waiver) including:

- Verify daily Scheduled Net Interchange with the RTO control areas and adjacent control areas, and if there are differences, resolve them within the time frame in NERC Policy 1.F.

- Operate to an “equal and opposite” Scheduled Net Interchange with the RTO control areas and adjacent control areas.

- Operate so that the Scheduled Net Interchange of the RTO (Sum of the Scheduled Net Interchanges with the RTO control areas and adjacent control areas) is zero (or equal to the RTO Inadvertent Payback as outlined below).

New Responsibilities

Financially settled Inadvertent would be removed from the control areas’ balances. The RTO inadvertent account would reflect the net RTO imbalance with the Interconnection. In order to accomplish this, the RTO would add “equal and opposite” schedules with the RTO control areas after the settlement. The net of these “settlement” schedules will be zero.

As requested by the NERC Resources Subcommittee, the RTO will report its Inadvertent Interchange balance to ECAR. RTO reporting will be consistent with the requirements and timelines for control areas outlined in Policy 1F. In addition, the RTO will maintain records of Inadvertent Interchange financially settled with each control area and will provide AIE data (pre and post settlement) for any surveys or formal data requests.

The RTO will manage and pay back its net Inadvertent Interchange balance following NERC policy. Inadvertent payback will be initiated based on an objective and publicly available process that is triggered on balances exceeding statistical norms (allows normal “breathing” of balances). Inadvertent Payback will be done during periods and in amounts such that payback will not burden others or interfere with time corrections. Financial gain will not factor into the decision to payback or recover Inadvertent Interchange.

Current Operating Reliability

This waiver request is to accommodate after-the-fact transfer of financially settled Inadvertent Interchange. The waiver has no impact on real-time balancing performed by the control areas. The RTO will always operate with a “net zero” Scheduled Interchange. The waiver will not affect the way the RTO control areas perform or calculate CPS and DCS.

The Control Area Participants believe this waiver promotes reliability for two reasons:

- It eliminates the incentive for burdening the Interconnection by manipulating imbalances for financial gain (taking in inadvertent during periods of high price and returning it when prices
subside). This is consistent with NERC Operating Committee’s charge to the Joint Inadvertent Interchange Task Force (JIITF) and moves the JIITF’s recommendations closer to realization.

- Increased transparency as the influence of RTO’s markets on the Interconnection will be apparent through this separate RTO Inadvertent Interchange account. Any scheduling or process errors would be traceable through this account.
All CONTROL AREAS share the benefits of interconnected systems operation and, by their participation in NERC, they recognize the need to operate in a manner that will promote reliability in interconnected operation and not burden other interconnected CONTROL AREAS.

All CONTROL AREAS shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency. Multiple outages of a credible nature shall also be examined and, when practical, the CONTROL AREAS shall operate to protect against instability, uncontrolled separation, or cascading outages resulting from these multiple outages.

As stated in the NERC Bylaws, “A Member or Affiliate Member Regional Council, on behalf of its members, shall agree, in writing, to accept the responsibility to promote, support, and comply with the purposes and policies of the Corporation as set forth in its Certificate of Incorporation, Bylaws, and Planning and Operating Policies that from time to time may be amended, adopted, or approved.”

NERC expects all CONTROL AREAS to operate their bulk electric systems according to the standards, and Requirements in these Operating Policies. If a CONTROL AREA is not able to comply with the conditions and terms of a particular, standard or requirement, it must notify other affected CONTROL AREAS and its Regional Council who will report the non-compliance to the NERC Operating Committee. This notification will provide an opportunity to develop mutually acceptable strategies to mitigate any adverse effects arising out of instances of noncompliance.

Many of the Operating Policies include specific guidelines for determining compliance. NERC conducts periodic reviews of all CONTROL AREAS and Independent System Operators through the Operating Committee’s Compliance Subcommittee. These reviews are conducted in accordance with the compliance guidelines in these Policies plus guidelines that the subcommittee has established. NERC also reviews specific instances where it suspects that Operating Policies have been violated.
Introduction to the Operating Policies

Subsections

A. Policies, Standards, Requirements, and Guides – Definitions and Obligations
B. Control Area Concepts and Obligations
C. Reliability Coordinators
D. Operating Policy Layout

A. Policies, Standards, Requirements, and Guides – Definitions and Obligations

Obligations

NERC’s doctrine for interconnected systems operation consists of Standards, Requirements, and Guides. Together, these form NERC’s Operating Policies. NERC Operating Policies place the responsibility for operating reliability primarily on the CONTROL AREAS that operate within the four INTERCONNECTIONS of the United States and Canada and northern Baja California Norte, Mexico.

NERC recognizes that in the open access transmission environment, CONTROL AREAS are assigning some of their responsibilities, especially for transmission security, to other entities. These entities include Independent System Operators, and RELIABILITY COORDINATORS. The CONTROL AREAS who assign responsibilities to other entities must ensure, through agreements or otherwise, that those entities comply with the NERC Operating Policies.

PURCHASING-SELLING ENTITIES are also responsible for fulfilling their informational and procedural obligations, and to keep records that document this compliance.

Definitions

Standards are, in essence, Requirements that are measurable and auditable with surveys.

Requirements describe the obligations of a CONTROL AREA and related functions such as TRANSMISSION PROVIDERS, RELIABILITY COORDINATORS, PURCHASING-SELLING ENTITIES, and other entities who use CONTROL AREA services.

NERC Bylaws require mandatory compliance with Standards and Requirements.

Guides are operating practices that control areas, and related functions such as Transmission Providers, RELIABILITY COORDINATORS, PURCHASING-SELLING ENTITIES, and other entities who use CONTROL AREA services, may wish to consider. The application of Guides is optional, and may vary among these entities to accommodate local conditions and individual system requirements.
B. Control Area Concepts and Obligations

1. The Interconnections
The electric systems in the United States and Canada comprise three INTERCONNECTIONS:

Eastern INTERCONNECTION — the largest INTERCONNECTION. It covers an area from Québec to Florida and from eastern New Mexico to Saskatchewan, and has direct-current connections to the Western and ERCOT INTERCONNECTIONS.

Western INTERCONNECTION — second largest, extending from Alberta and British Columbia in the north to Baja California Norte, Mexico, and Arizona and New Mexico in the south. It has several direct-current connections to the Eastern INTERCONNECTION.

ERCOT INTERCONNECTION — includes most of the electric systems in Texas. It has two direct-current connections to the Eastern INTERCONNECTION.

2. Interconnection Control — Role of the Control Areas
For each of the INTERCONNECTIONS to operate safely and reliably and provide dependable electric service to its customers, it must be continuously monitored and controlled. This monitoring and control function is distributed among the control areas that comprise the INTERCONNECTION.

Control Area Definition
A CONTROL AREA is an electrical system bounded by interconnection (tie-line) metering and telemetry. It controls its generation directly to maintain its interchange schedule with other CONTROL AREAS and contributes to frequency regulation of the INTERCONNECTION.

This means that a CONTROL AREA is an electric system that meets the following two requirements. It can:

- Directly control its generation to continuously balance its actual interchange and scheduled interchange, and
- Help the entire Interconnection regulate and stabilize the INTERCONNECTION’S alternating-current frequency.


Introduction to the Operating Policies

B. Control Area Concepts and Obligations

**Balancing Actual and Scheduled Interchange**

A **CONTROL AREA** is connected to other **CONTROL AREAS** with tie lines. The **CONTROL AREAS** on either end of a tie both know how much energy is flowing from one to the other because they meter the tie at a common point. By adding the tie line meter readings (with energy flowing out as positive and flowing in as negative), the control area can calculate its net actual interchange with the rest of the **INTERCONNECTION**. A **CONTROL AREA** controls its actual interchange and contributes to INTERCONNECTION frequency regulation by adjusting its generation through its automatic generation control system, or AGC.

A **CONTROL AREA**’s scheduled interchange is the sum of all the interchange schedules the **CONTROL AREA** has with all other **CONTROL AREAS**. This sum is the **CONTROL AREA**’s net scheduled interchange with the rest of the **INTERCONNECTION**. The **CONTROL AREA** is obligated to control its generation to attempt to match its net actual interchange to its net scheduled interchange.1 The **INTERCONNECTION** supplies or absorbs the difference between the actual and scheduled interchange. This difference is called inadvertent interchange.

**Regulating and Stabilizing Interconnection Frequency**

A **CONTROL AREA**’s second obligation is contributing to Interconnection frequency regulation. The frequency throughout an Interconnection is essentially the same. Frequency regulation is handled by the AGC systems that measure Interconnection frequency and adjust generation to change actual frequency to match scheduled frequency (usually 60 Hz).

**CONTROL AREAS** also contribute to stabilizing Interconnection frequency through their generator governors, which measure Interconnection frequency by measuring the speed of the generators’ turbine shaft. The governors respond to frequency deviations by opening steam or water valves when frequency declines to increase the control areas’ generation. The opposite happens when frequency increases.

**Tie-Line Bias Control**

Tie-line bias control in a **CONTROL AREA**’s AGC system allows the control area to control its generation to match its net actual interchange to its net scheduled interchange, contribute to frequency regulation, and allow generator governors to adjust generation to respond to large frequency deviations.

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1 It is impossible to control generation so precisely to keep these two exactly equal. A **CONTROL AREA** is obligated to keep the difference between its actual and scheduled interchange within limits that NERC specifies in its Control Performance Standard.
Recognition as a Control Area

To be recognized as a NERC CONTROL AREA, a system must be reviewed and confirmed by the Region and NERC Resources Subcommittee representative that the system meets the following basic requirements:

- Operates generation.
- Has metered connections (ties) with other control areas and the necessary contracts to use those connections.
- Has the ability to control generation and match its net actual interchange to its net scheduled interchange.
- Has generator governors that are allowed to respond properly to INTERCONNECTION frequency changes.
- Uses tie-line bias control (unless doing so would be adverse to its or the INTERCONNECTION’S reliability).
- Has a control center with 24-hour-per-day staffing.

Compliance with Operating Policies

A CONTROL AREA is obligated to adhere to all NERC Operating, Requirements, and Standards. NERC Operating Guides are operating practices that control areas may wish to consider.

When a CONTROL AREA determines that an Operating Requirement, or Standard does not apply to its circumstances, it may ask the NERC Operating Committee for a waiver. The control area must show that this waiver will not burden other CONTROL AREAS in the INTERCONNECTION.

Regional Councils, power pools, or other associations also may impose their own operating criteria and procedures.

Reporting

Inadvertent Interchange Accounting — Each CONTROL AREA shall manage inadvertent interchange in accordance with NERC Operating Policy 1F. — Inadvertent Interchange Management. Monthly summaries are required as detailed in Appendix 1F. — Inadvertent Interchange Energy Accounting Practices.

Control Performance Surveys — Each CONTROL AREA shall respond to requests for Control Performance Standards (CPS) Surveys. Control Performance Surveys are required to demonstrate that each CONTROL AREA is able to continuously balance its actual interchange to its scheduled interchange. Procedures and forms are in the Performance Standard Reference Document.

Area Interchange Error Surveys — Each CONTROL AREA is required to continually balance its actual interchange to its scheduled interchange, plus contribute to Interconnection frequency regulation. 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 or
decrease. An AIE Survey is a means of determining which control areas are contributing to an INTERCONNECTION imbalance. Procedures and forms are in the Area Interchange Error Survey Training Document.

**Frequency Response Characteristic Surveys** — Each CONTROL AREA will respond to a frequency change through:

- Instantaneous demands, which change proportionally to frequency changes, and
- Generation, which changes inversely to frequency changes through governor control.

Surveys are usually requested when a significant frequency deviation occurs to determine the frequency response characteristic of each CONTROL AREA. Procedures and forms are in the Frequency Response Characteristic Survey Training Document.

**Frequency Bias Settings** — Frequency bias is a value, in MW/0.1 Hz, set into a CONTROL AREA’s AGC equipment to represent the control area’s response to frequency deviations. Frequency bias setting data are requested annually.

**Allowable Limit of Average Deviation Surveys (L_d)** — L_d is the compliance limit for the A2 criterion described in the Performance Standard Reference Document. L_d surveys are made annually.
C. Reliability Coordinators

Establishment of the Reliability Coordinator Function
The NERC Board of Trustees established the RELIABILITY COORDINATOR function with its approval of the Security Process Task Force Report in May 1996. This action:

• Established requirements for the sharing of data and information about the “health” of the Interconnection.
• Established an Interregional Security Network for each Interconnection.
• Required that every Region, subregion, or interregional coordinating group establish a RELIABILITY COORDINATOR to provide the security assessment and emergency operations coordination for the control areas within the Regions and across the Regional boundaries.
• Required that each Region must develop a security plan to meet NERC Policies, Standards, and Requirements that deal with operational security. The Regional Reliability Plan also details how the RELIABILITY COORDINATOR(S) for the Region will be put in place. The NERC Operating Committee was given responsibility and authority to approve the Regional Reliability Plans.
• Required that information sharing and coordinated emergency operating procedures rely on common operating terminology, criteria, and standards.

Role of the Security Coordinators
The role of the RELIABILITY COORDINATOR is described in detail throughout these Operating Policies. Regardless of specific organization of the RELIABILITY COORDINATOR(S) for a Region, the RELIABILITY COORDINATOR must:

• Have all of the necessary information to monitor the “big picture”
• Be able to assess the security of the Region or Interconnection
• Coordinate certain emergency control actions
• Be operational 24 hours per day, seven days per week.

Recognition as a Security Coordinator

Security Coordinators Under Purview of Regional Council
1. To be recognized as a NERC RELIABILITY COORDINATOR, it must be included in a Regional Reliability Plan approved by the NERC Operating Committee.
2. The Regional Reliability Plan must reflect Reliability Areas within that Regional Council that are covered by other Reliability Organizations (see below).
3. The Regional Council must bring any changes to its Reliability Plan to the Operating Reliability Subcommittee for review and the Operating Committee for approval.
4. The Operating Reliability Subcommittee forwards the results if its review to the NERC Operating Committee.

Reliability Coordinators Under Purview of Other Reliability Organization
This approval procedure pertains to the RELIABILITY COORDINATOR under the purview of an ISO, RTO, or other Reliability Organization (RO).
1. RO presents its Reliability Plan to applicable NERC Region(s) where it is proposing to provide Reliability Coordination Services for endorsement.
2. RO submits its Reliability Plan, accompanied by Regional Council’s endorsement, to the Operating Reliability Subcommittee for review and the Operating Committee for approval,
3. The Operating Reliability Subcommittee forwards the results of its review to the NERC Operating Committee

Changes to a RELIABILITY COORDINATOR’s Reliability Area boundary must be:

1. Endorsed by the applicable NERC Region(s),

2. Accompanied by Regional Councils updates to their Regional Reliability Plans to reflect the Reliability Area remaining within the Regional Council’s purview.
   a. The Regional Council shall terminate its Reliability Plan if the entire Region is within the Reliability Area of another RO.

3. Submitted to the Operating Reliability Subcommittee for review and the NERC Operating Committee as an amendment to the controlling RO and Regional Councils’ Reliability Plans, and.

4. The Operating Reliability Subcommittee forwards the results of its review to the NERC Operating Committee.

5. Approved by NERC OC before implementation.

The establishment of the NERC RELIABILITY COORDINATOR function with its supporting infrastructure was a costly and technically challenging industry endeavor. In order to enhance the security of the Interconnections, it is necessary to ensure the orderly evolution of the NERC RELIABILITY COORDINATOR function. Therefore, any changes to the number of RELIABILITY COORDINATORS or the boundaries of the Reliability Area under the purview of a RELIABILITY COORDINATOR must be proposed to the NERC Operating Committee as an amendment to the controlling Regional Reliability Plan(s) and be approved before implementation.
D. Operating Policy Layout

Policy 7 — Telecommunications

Policy Subsections
A. Facilities
B. System Operator Telecommunication Procedures
C. Loss of Telecommunications

A. Facilities

Introduction
Explanation of the purpose of this Policy section.

Requirements
1. **Reliable and secure networks.** Reliable and secure telecommunications networks shall be provided within and among systems, control areas, pools, and Regions.

2. **Exclusive channels.** Exclusive telecommunications channels shall be provided between the system control center and the control center of each adjacent connecting system.

3. **Testing.** All telecommunications channels shall be tested regularly or monitored on-line. Special attention should be given to emergency telecommunications channels and channels not used for routine communications.

Compliance
Specific guidelines for the compliance reviews would be explained here. For example, required recordkeeping or description of how compliance with the Requirement will be measured.

Guides
1. **General provisions.** Telecommunications networks should be provided for voice, AGC, SCADA, special protection systems, and protective relaying where appropriate.

2. **Computer data exchange.** Computer data exchange should be considered where appropriate.
Terms Used in the Policies

**ACTUAL INTERCHANGE.** The metered interchange over a specific INTERCONNECTION between two PHYSICALLY ADJACENT CONTROL AREAS.

**ANTI-ALIASING FILTER.** An analog filter installed at a metering point to remove aliasing errors from the data acquisition process. The filter is designed to remove the high frequency components of the signal over the AGC sample period.

**ADEQUATE REGULATING MARGIN.** The minimum on-line capacity that can be increased or decreased to allow the system to respond to all reasonable demand changes in order to be in compliance with the Control Performance Standard.

**ADJACENT CONTROL AREAS.** Two CONTROL AREAS that are interconnected:
- Directly to each other, or
- Via a multi-party agreement or transmission tariff. (Examples include Independent System Operator and Power Pool agreements.)

**AREA CONTROL ERROR (ACE).** The instantaneous difference between net actual and scheduled interchange, taking into account the effects of frequency bias including a correction for meter error.

**AUTOMATIC GENERATION CONTROL (AGC).** Equipment that automatically adjusts a CONTROL AREA’S generation from a central location to maintain its interchange schedule plus frequency bias.

**BULK ELECTRIC SYSTEM.** The aggregate of electric generating plants, transmission lines, and related equipment. The term may refer to those facilities within one electric utility, or within a group of utilities in which the transmission lines are interconnected.

**CAPACITY EMERGENCY.** A capacity emergency exists when a system’s or pool’s operating capacity, plus firm purchases from other systems, to the extent available or limited by transfer capability, is inadequate to meet its demand plus its regulating requirements.

**CLOCK HOUR.** The 60-minute period ending at :00. All surveys, measurements, and reports are based on clock hour periods unless specifically noted.

**COMMONLY OR JOINTLY OWNED UNITS (COU/JOU).** These terms may be used interchangeably to refer to a unit in which two or more CONTROL AREAS share ownership.

**CONTRACT INTERMEDIARY CONTROL AREA.** A NERC CONTROL AREA that has connecting facilities in the SCHEDULING PATH between the SENDING CONTROL AREA and RECEIVING CONTROL AREAS and operating agreements that establish the conditions for the use of such facilities.

**CONTROL AREA.** An electrical system bounded by interconnection (tie-line) metering and telemetry. It controls generation directly to maintain its INTERCHANGE SCHEDULE with other CONTROL AREAS and contributes to frequency regulation of the INTERCONNECTION.

**CONSTRAINED FACILITY.** A transmission facility (line, transformer, breaker, etc.) that is approaching, is at, or is beyond its OPERATING SECURITY LIMIT.

**CONSTRAINT.** A limitation placed on INTERCHANGE TRANSACTIONS that flow over a CONSTRAINED FACILITY.
DEMAND. The rate at which energy is being used by the customer.

DISTRIBUTION FACTOR (DF). The portion of an INTERCHANGE TRANSACTION, expressed in per unit that flows across a transmission facility (Flowgate).

DISTURBANCE. 1. Any perturbation to the electric system. 2. The unexpected change in ACE that is caused by the sudden loss of generation or interruption of load.

DYNAMIC SCHEDULE. A telemetered reading or value that is updated in real time and used as a schedule in the AGC/ACE equation and the integrated value of which is treated as a schedule for interchange accounting purposes. Commonly used for “scheduling” jointly owned generation to or from another CONTROL AREA.

ENERGY DEFICIENT ENTITY. A LOAD SERVING ENTITY who foresees or is experiencing an ENERGY EMERGENCY situation.

ENERGY EMERGENCY. A condition when a LOAD SERVING ENTITY has exhausted all other options and can no longer provide its customers’ expected energy requirements.

FREQUENCY BIAS SETTING. A value, in MW/0.1 Hz, set into a CONTROL AREA’s AGC equipment to represent a CONTROL AREA’s response to a frequency deviation.

HOST CONTROL AREA. 1. A CONTROL AREA that confirms and implements INTERCHANGE TRANSACTIONS for a PURCHASING-SELLING ENTITY that operates generation or serves customers directly within the CONTROL AREA’S metered boundaries. 2. The CONTROL AREA within whose metered boundaries a jointly owned unit is physically located.

HOURLY VALUE. Data measured on a clock-hour basis.

INADVERTENT INTERCHANGE. The difference between the CONTROL AREA’s NET ACTUAL INTERCHANGE and NET SCHEDULED INTERCHANGE.

INTERCHANGE. Energy transfers that cross CONTROL AREA boundaries.

INTERCHANGE ARRANGEMENT. The process of finding a seller and buyer for an interchange transaction, plus reserving TRANSMISSION SERVICES.

INTERCHANGE CONFIRMATION. Agreement of the terms of the INTERCHANGE SCHEDULE prior to its implementation.

INTERCHANGE DISTRIBUTION CALCULATOR. The mechanism used by SECURITY COORDINATORS in the Eastern Interconnection to calculate the distribution of INTERCHANGE TRANSACTIONS over specific transmission interfaces, which are known as “Flowgates.” It includes a database of all INTERCHANGE TRANSACTIONS and a matrix of the Distribution Factors for the Eastern Interconnection.

INTERCHANGE IMPLEMENTATION. The physical initiation of the INTERCHANGE SCHEDULE by entering it into the CONTROL AREA’S energy management system or by approving a schedule that has been electronically transferred into the energy management system.

INTERCHANGE SCHEDULE. The planned INTERCHANGE between two ADJACENT CONTROL AREAS that results from the implementation of one or more INTERCHANGE TRANSACTION(S).
INTERCHANGE TRANSACTION. A TRANSACTION that crosses one or more Control Area boundaries.

INTERCHANGE TRANSACTION CANCELLATION. The complete withdrawal of an INTERCHANGE TRANSACTION by a PURCHASING-SELLING ENTITY prior to the start time of the TRANSACTION.

INTERCHANGE TRANSACTION TERMINATION. The complete interruption of an INTERCHANGE TRANSACTION by a PURCHASING-SELLING ENTITY after the start time of the TRANSACTION.

INTERCHANGE TRANSACTION CURTAILMENT. The complete or partial interruption of an INTERCHANGE TRANSACTION that has started or “holding” of a new INTERCHANGE TRANSACTION that has not yet started by a TRANSMISSION PROVIDER, SECURITY COORDINATOR, or CONTROL AREA to maintain operating security.

INTERCONNECTION. When capitalized, any one of the three bulk electric system networks in North America: Eastern, Western, and ERCOT. When not capitalized, the facilities that connect two systems or CONTROL AREAS.

INTERMEDIARY CONTROL AREA. A CONTROL AREA on the SCHEDULING PATH between the SOURCE CONTROL AREA and SINK CONTROL AREA.

INTERMITTENT LOAD. Demand that can be interrupted by direct action of the supplying system’s system operator in accordance with contractual provisions.

LEAP SECOND. A second of time added occasionally by the National Institute of Standards and Technology to correct for the offset between the clock-hour day and the solar day.

LOAD. The amount of electric power delivered or required at any specified point or points on a system.

LOAD-SERVING ENTITY. The entity who serves the end-use customer’s energy requirements.

JOINT CONTROL. Automatic generation control of jointly owned units by two or more CONTROL AREAS.

METERED VALUE. A measured electrical quantity that may be collected by telemetering, SCADA, or other means.

NET ACTUAL INTERCHANGE. The algebraic sum of all metered interchange over all INTERCONNECTIONS between two PHYSICALLY ADJACENT CONTROL AREAS.

NET INTERCHANGE SCHEDULE (OR NET SCHEDULE). The algebraic sum of all INTERCHANGE SCHEDULES with each ADJACENT CONTROL AREA.

NET SCHEDULED INTERCHANGE. The net of all INTERCHANGE SCHEDULES with all ADJACENT CONTROL AREAS. It is, in essence, the scheduled interchange with the INTERCONNECTION.

NET ENERGY FOR LOAD. Net system generation plus INTERCHANGE received minus INTERCHANGE delivered.

NON-SPINNING RESERVE. That operating reserve not connected to the system but capable of serving demand within a specified time, or interruptible load that can be removed from the system in a specified time.

OPERATING AUTHORITY. An entity that:
1. Has ultimate accountability for a defined portion of the BULK ELECTRIC SYSTEM to meet one or more of three reliability objectives – generation/demand balance, transmission security, and/or emergency preparedness; and

2. Is accountable to NERC and its Regional Reliability Councils for complying with NERC and Regional Policies; and

3. Has the authority to control or direct the operation of generating resources, transmission facilities, or loads, to meet these Policies.

OPERATING RESERVE. That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. It consists of spinning and non-spinning reserve.

OPERATING SECURITY. The ability of a power system to withstand or limit the adverse effects of any credible contingency to the system including overloads beyond emergency ratings, excessive or inadequate voltage, loss of stability or abnormal frequency deviations.

OPERATING SECURITY LIMIT. The value of a system operating parameter (e.g. total power transfer across an interface) that satisfies the most limiting of prescribed pre- and post-contingency operating criteria as determined by equipment loading capability and acceptable stability and voltage conditions.

OVERLAP REGULATION SERVICE. A method of providing regulation service in which the CONTROL AREA providing the regulation service incorporates all of the other CONTROL AREA’s tie lines, frequency response, and schedules into its own AGC/ACE equation.

PHYSICALLY ADJACENT CONTROL AREAS. Two CONTROL AREAS that are directly interconnected with each other.

PSEUDO-TIE. A telemetered reading or value that is updated in real time and used as a tie line flow in the AGC/ACE equation but for which no physical tie or energy metering actually exists. The integrated value is used as a metered MWh value for interchange accounting purposes.

PURCHASING-SELLING ENTITY (PSE). An entity that is eligible to purchase or sell energy or capacity and reserve transmission services.

RECEIVING CONTROL AREA. The CONTROL AREA importing the INTERCHANGE.

REGION. One of the NERC Reliability Councils.

REGIONAL SECURITY PLAN. The plan that explains how the Regional Council will meet the NERC Operating Policies that deal with operational security.

REGULATION SERVICE. The process whereby one CONTROL AREA contracts to provide corrective response to all or a portion of the ACE of another CONTROL AREA. The controlling utility assumes the obligation of meeting all applicable control criteria as specified by NERC. Adjustments to control parameters shall be per applicable NERC Operating Policies. Control may be transferred by transmittal of an ACE quantity or the transmittal of the actual tie flows and corresponding schedules (see Overlap Regulation Service and Supplemental Regulation Service).
RELIABILITY COORDINATOR.  An entity that provides the security assessment and emergency operations coordination for a group of CONTROL AREAS.  RELIABILITY COORDINATORS must not participate in the wholesale or retail merchant functions.

RESERVE SHARING GROUP.  A group whose members consist of two or more CONTROL AREAS that collectively maintain, allocate, and supply operating reserves required for each CONTROL AREA’s use in recovering from contingencies within the group.  Scheduling energy in from an adjoining CONTROL AREA to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period which the supplying party could reasonably be expected to load generation in (e.g., ten minutes).  If the transaction is ramped in quicker (e.g., between zero and ten minutes) then, for the purposes of Disturbance Control Performance, the areas become a reserve sharing group.

SCHEDULE (verb).  To set up a plan or arrangement for an INTERCHANGE TRANSACTION.

SCHEDULE (noun).  An INTERCHANGE SCHEDULE.

SCHEDULING ENTITY – An entity responsible for approving and implementing INTERCHANGE SCHEDULES.  SCHEDULING ENTITY refers to a CONTROL AREA or a third party authorized by NERC for this function, such as a Scheduling Agent.

SCHEDULING PATH.  The TRANSMISSION SERVICE arrangements reserved by the PURCHASING-SELLING ENTITY for a TRANSACTION.

SCHEDULED TOTAL INTERCHANGE.  The net of all INTERCHANGE SCHEDULES with all ADJACENT CONTROL AREAS.  It is, in essence, the scheduled interchange with the INTERCONNECTION.

SECURITY AREA.  The group of CONTROL AREAS under the purview of a SECURITY COORDINATOR.

SECURITY COORDINATOR FUNCTION.  The process of maintaining bulk transmission security for a CONTROL AREA, group of CONTROL AREAS, subregion, etc.

SECURITY COORDINATOR INFORMATION SYSTEM (SCIS).  A generic reference to the communication system in the Eastern Interconnection, the WSCCnet (Western Interconnection), and the ERCOT Communication System as applicable.

SENDING CONTROL AREA.  The CONTROL AREA exporting the INTERCHANGE

SINK CONTROL AREA.  The CONTROL AREA in which the load (sink) is located for an INTERCHANGE TRANSACTION.  (This will also be a RECEIVING CONTROL AREA for the resulting INTERCHANGE SCHEDULE.)

SOURCE CONTROL AREA.  The CONTROL AREA in which the generation (source) is located for an INTERCHANGE TRANSACTION.  (This will also be a SENDING CONTROL AREA for the resulting INTERCHANGE SCHEDULE.)

SUBREGION.  A portion of a Region.

SUPPLEMENTAL REGULATION SERVICE.  A method of providing regulation service in which the CONTROL AREA providing the regulation service receives a signal representing all or a portion of the other CONTROL AREA’s ACE.
SUPERVISORY CONTROL AND DATA ACQUISITION (SCADA). A system of remote control and telemetry used to monitor and control the transmission system.

SPECIAL PROTECTION SYSTEM. A protection system designed to perform functions other than the isolation of electrical faults. Also called “remedial action scheme.”

SPINNING RESERVE. Unloaded generation that is synchronized and ready to serve additional demand.

STATION SERVICE. The electric supply for the ancillary equipment used to operate a generating station or substation.

STATION SERVICE GENERATOR. A generator (usually found in hydro plants) used to supply electric energy for station service equipment.

SUPPLEMENTAL REGULATION SERVICE. A method of providing regulation service in which the CONTROL AREA providing the regulation service receives a signal representing all or a portion of the other CONTROL AREA’s ACE.

SYSTEM. A combination of generation, transmission, and distribution components comprising an electric utility, or group of utilities.

SYSTEM OPERATOR. A person authorized to operate or supervise the operation of the bulk electric system.

SYSTEM PERSONNEL. Those people who have the capability to affect system operations and who must abide by the authority vested in the System Operator. May include power plant operators, system maintenance personnel, power schedulers, power marketers, etc.

TOTAL ACTUAL INTERCHANGE. The algebraic sum of all INTERCHANGE metered with all PHYSICALLY ADJACENT CONTROL AREAS. It is, in essence, the actual interchange with the Interconnection.

TRANSACTION. An agreement arranged by a PURCHASING-SELLING ENTITY to transfer energy from seller to a buyer.

TRANSMISSION OPERATING ENTITY. An entity that owns, operates, or manages transmission facilities, which may include CONTROL AREAS, transmission owners within the CONTROL AREA, pools, subregions, Regions, or combinations of CONTROL AREAS, pools, subregions, or Regions.

TRANSMISSION PROVIDER. As defined by FERC, the public utility (or its Designated Agent) that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce and provides transmission service under the Tariff. As used in the NERC Policies: Any entity that provides Transmission Service.

TRANSMISSION SERVICE. (FERC-defined term) Point-To-Point Transmission Service provided under Part II of the Tariff on a firm and non-firm basis.
Control Area Criteria

Version 2

Criteria Subsections

A. Confirmation as a Control Area

B. Criteria

Introduction

These Criteria establish the requirements for consideration as a NERC-Certified CONTROL AREA. They are based on existing NERC Operating Policies and Standards.

A. Confirmation as a Control Area

1. Confirmation by Regional Council. To be recognized as a NERC-Certified CONTROL AREA, the entity must be reviewed and confirmed by the REGIONAL COUNCIL in which the entity is a member that it meets the requirements of these Criteria.

B. Criteria for a Control Area

1. Generation. The CONTROL AREA shall operate generation or have the necessary contracts to operate generation to:

   1.1. Meet its area instantaneous demand, INTERCHANGE SCHEDULE, OPERATING RESERVE, and Reactive resource requirements.

   1.2. Provide its frequency bias obligations.

   1.3. Balance its NET ACTUAL INTERCHANGE and NET SCHEDULED INTERCHANGE

   1.4. Use tie-line bias control (unless doing so would be adverse to system or the INTERCONNECTION reliability).

   1.5. Comply with Control Performance and Disturbance Control Standards (see Policy 1E, “Generation Control and Performance – Performance Standard”)

   1.6. Repay its INADVERTENT INTERCHANGE balance. (see Policy 1F, “Generation Control and Performance – Inadvertent Interchange”)

2. Metering. The CONTROL AREA shall have meters on all tie lines with adjacent CONTROL AREAS to record actual interchange (MW) in real time. INTERCHANGE meters shall be at a location common to both CONTROL AREAS, and provide identical values with opposite signs to both CONTROL AREAS. All CONTROL AREA interconnection points shall be equipped with common MWh meters, with readings provided hourly to the control centers of both CONTROL AREAS.

3. Communications. The CONTROL AREA shall have adequate and reliable communication facilities to assure the exchange of information necessary to maintain Interconnection reliability.
4. Transmission arrangements. The CONTROL AREA shall have appropriate transmission arrangements (through ownership or contracts) to meet its generation and load obligations.

5. System operators. The CONTROL AREA shall be operated by NERC-certified system operators 24 hours per day, seven days per week.

6. E-tag services. The CONTROL AREA shall provide E-Tag Tag Authority and Tag Approval services. (Eastern and Western Interconnections)

7. Performance surveys. The CONTROL AREA shall comply with performance survey requirements. (see Policy 1G, “Generation Control and Performance – Control Surveys”)

8. Back-up Control Center. The CONTROL AREA shall provide a plan to continue operation in the event its control center becomes inoperable.

9. Coordination. The CONTROL AREA shall coordinate maintenance and protective relaying that may affect reliability and other systems with those other systems and the Security Coordinator.

10. System Restoration. The CONTROL AREA shall have a restoration plan to reestablish its electric system and cover emergency conditions.

11. Compliance with NERC Operating Policies and Standards. The CONTROL AREA shall have knowledge of and shall comply with all NERC approved Policies and Standards as currently posted.
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
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: ________________________________________________________
OPERATING POLICIES
Policy 1 – Generation Control and Performance

Version 2

Policy Subsections
A. Control Performance Standard
B. Disturbance Control Standard
C. Frequency Response and Bias
D. Time Control Standard
E. Automatic Generation Control Standard
F. Inadvertent Interchange Standard
G. Surveys Standard

Introduction
Each CONTROL AREA shall have access to and/or operate resources to provide for a level of OPERATING RESERVE sufficient to account for frequency support, errors in load forecasting, generation loss, transmission unavailability, and regulating requirements. Sufficient OPERATING RESERVES is defined as the capacity required to meet the Control Performance Standard (Section A), Disturbance Control Standard (Section B), and Frequency Response Standard (Section C) of this Policy.

A. Control Performance Standard

[Appendix 1A, “Area Control Error (ACE) Equation”]
[“Performance Standard Reference Document”]

Introduction
The CONTROL AREA balance between demand and supply (generation plus INTERCHANGE) is measured by its AREA CONTROL ERROR (ACE). Because supply and demand change unpredictably, there will often be a mismatch between them, resulting in non-zero ACE.

The Control Performance Standard (CPS) establishes the statistical boundaries for ACE magnitudes, ensuring that steady-state frequency is statistically bounded around its scheduled value. Each CONTROL AREA must achieve at least the minimum performance required by the CPS. CPS1 defines the permissible distribution of all CONTROL AREAS’ ACEs in an INTERCONNECTION and is based on expected frequency performance within that individual INTERCONNECTION. CPS2 limits the magnitude of the impact that a CONTROL AREA places on its respective INTERCONNECTION. Values controlling the effects of CPS are set by the Resources Subcommittee.

1. Monitoring. Each CONTROL AREA shall monitor its control performance against two Standards: CPS1 and CPS2.

1.1. Control Performance Standard (CPS1). On a rolling 12-month basis, the average of the clock-minute averages of a CONTROL AREA’s ACE divided by 10B (B is the clock-minute average of the CONTROL AREA’s frequency bias) times the corresponding clock-minute averages of the INTERCONNECTION’S FREQUENCY ERROR shall be less than a

\[
\frac{\text{AVG}_{\text{Period}} \left( \frac{\text{ACE}_i}{-10B_i} \right) \ast \Delta F_i}{\varepsilon_i^2} \leq 1 \quad \text{or} \quad \frac{\text{AVG}_{\text{Period}} \left[ \left( \frac{\text{ACE}_i}{-10B_i} \right) \ast \Delta F_i \right]}{\varepsilon_i^2} \leq 1
\]
A. Control Performance Standard

specific limit. This limit $\varepsilon_{10}^2$ is a constant derived from a targeted frequency bound (separately calculated for each INTERCONNECTION) reviewed and set as necessary by the NERC Resources Subcommittee. [See the “Performance Standard Reference Document” for application for variable frequency bias.]

1.2. Control Performance Standard (CPS2). The average ACE for at least 90% of clock-ten-minute periods (6 non-overlapping periods per hour) during a calendar month must be within a specific limit, referred to as $L_{10}$. [See the “Performance Standard Reference Document,” for the methods for calculating $L_{10}$.]

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

where:

$$L_{10} = 1.65 \varepsilon_{10} \sqrt{(-10B_i)(-10B_j)}$$

2. Control Performance Standard (CPS) Compliance. Each CONTROL AREA shall achieve, as a minimum, CPS1 compliance of 100% and CPS2 compliance of 90% [See the “Performance Standard Reference Document,” Section C].

2.1. CONTROL AREAS Participating in SUPPLEMENTAL REGULATION SERVICE. A CONTROL AREA providing or receiving SUPPLEMENTAL REGULATION SERVICE through DYNAMIC TRANSFER shall continue to be evaluated on the characteristics of its own ACE with the SUPPLEMENTAL REGULATION SERVICE included.

2.2. CONTROL AREAS Providing OVERLAP REGULATION SERVICE. A CONTROL AREA providing OVERLAP REGULATION SERVICE shall evaluate CPS1 and CPS2 using the characteristics of the combined CONTROL AREAS’ ACE and combined FREQUENCY BIAS SETTINGS.

2.3. CONTROL AREAS Receiving OVERLAP REGULATION SERVICE. A CONTROL AREA receiving OVERLAP REGULATION SERVICE shall not have its control performance evaluated (i.e. from a control performance perspective, the CONTROL AREA has shifted all control requirements to the CONTROL AREA providing overlap regulation).
B. Disturbance Control Standard

[Appendix 1A – Area Control Error Equation]
[Performance Standard Reference Document]

Introduction
The CONTROL AREA demand-supply balance will quickly change following the sudden loss of load or generation failure. This results in a sudden change in the CONTROL AREA’s ACE, and also a change in INTERCONNECTION frequency. The Disturbance Control Standard measures the CONTROL AREA’s ability to utilize its CONTINGENCY RESERVES following a REPORTABLE DISTURBANCE. Because generator failures are far more common than significant losses of load and because CONTINGENCY RESERVE activation does not typically apply to the loss of load, the application of the Disturbance Control Standard is limited to the loss of supply and does not apply to the loss of load.

Each CONTROL AREA shall have access to and/or operate resources to provide for a level of CONTINGENCY RESERVE sufficient to meet the DCS performance standards.

RESERVE SHARING GROUPS shall have the same responsibilities and meet the same obligations as individual CONTROL AREAS with regards to monitoring and meeting the Disturbance Control Standard.

Standards

1. CONTINGENCY RESERVES. Each CONTROL AREA shall have access to and/or operate CONTINGENCY RESERVES to respond to DISTURBANCES. This CONTINGENCY RESERVE is that part of the OPERATING RESERVES that is available, following loss of resources by the CONTROL AREA, to meet the Disturbance Control Standard (DCS). CONTINGENCY RESERVE may be supplied from generation, controllable load resources, or coordinated adjustments to INTERCHANGE SCHEDULES.

1.1. CONTINGENCY RESERVE Accounting. The same portion of RESOURCE CAPACITY shall not be counted by more than one entity (e.g. reserves from jointly owned generation) as part of its CONTINGENCY RESERVES.

1.2. REGIONAL CONTINGENCY RESERVE Policies. Each Region, subregion or RESERVE SHARING GROUP shall specify its CONTINGENCY RESERVE policies, including the minimum reserve requirement for the group, its allocation among members, the permissible mix of OPERATING RESERVE – SPINNING and OPERATING RESERVE – SUPPLEMENTAL that may be included in CONTINGENCY RESERVE, and the procedure for applying CONTINGENCY RESERVE in practice, and the limitations, if any, upon the amount of interruptible load that may be included.

2. CONTINGENCY RESERVE to meet Disturbance Control Standard. Each CONTROL AREA or RESERVE SHARING GROUP shall activate sufficient CONTINGENCY RESERVE to comply with the NERC Disturbance Control Standard. As a minimum the CONTROL AREA, or RESERVE SHARING GROUP, shall carry at least enough CONTINGENCY RESERVES to cover the MOST SEVERE SINGLE CONTINGENCY.

2.1. Contingency review. All RESERVE SHARING GROUPS and CONTROL AREAS shall at least annually review their probable contingencies to determine their prospective MOST SEVERE SINGLE CONTINGENCIES.

2.2. Disturbance Control Standard Compliance. When a CONTROL AREA or RESERVE SHARING GROUP experiences a REPORTABLE DISTURBANCE (SEE 2.4), it is compliant
with the Disturbance Control Standard when the Disturbance Recovery Criterion is met within the Disturbance Recovery Period. Each Control Area or Reserve Sharing Group shall meet the Disturbance Control Standard (DCS) 100% of the time for Reportable Disturbances.

2.2.1. Disturbance Recovery Criterion. The Control Area shall return its ACE to zero if its ACE just prior to the Disturbance was positive or equal to zero. For negative initial ACE values just prior to the Disturbance, the ACE must return to its pre-disturbance value. The default performance criterion described above may be adjusted to better suit the needs of an Interconnection based on analysis approved by the NERC Resources Subcommittee and the NERC Operating Committee.

2.2.2. Disturbance Recovery Period. The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance. This period may be adjusted to better suit the needs of an Interconnection based on analysis approved by the NERC Resources Subcommittee and the NERC Operating Committee.

2.3. Reserve Sharing Group. Each Reserve Sharing Group shall comply with the Disturbance Control Standard. A Reserve Sharing Group shall be considered in a Disturbance condition whenever a group member has experienced a Reportable Disturbance and calls for the activation of Contingency Reserves from one or more other group members. (If a group member has experienced a Reportable Disturbance condition but does not call for reserve activation from other members of the Reserve Sharing Group, then that member shall report as a single Control Area.) Compliance may be demonstrated by either of the following two methods:

2.3.1. Group compliance to Disturbance Control Standard. The Reserve Sharing Group reviews group ACE (or equivalent) and demonstrates compliance to the DCS. To be in compliance, the group ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

2.3.2. Group member compliance to Disturbance Control Standard. The Reserve Sharing Group reviews each member’s ACE in response to the activation of reserves. To be in compliance, a member’s ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period. [See Requirement 2.2.2 above.]

2.4. Reportable Disturbances. Reportable Disturbances are contingencies that are greater than or equal to 80% of the Most Severe Single Contingency loss. Regions may optionally reduce the 80% threshold, provided that normal operating characteristics are not being considered or misrepresented as contingencies. Normal operating characteristics are excluded because DCS only measures the recovery from sudden, unanticipated losses of supply-side resources.

2.5. Treatment of Multiple Contingencies.

2.5.1. Simultaneous Contingencies. Multiple contingencies occurring within one minute or less of each other shall be treated as a single contingency. If the combined magnitude of the multiple contingencies exceeds the Most Severe
SINGLE CONTINGENCY, the loss shall be reported, but excluded from compliance evaluation.

2.5.2. **Multiple Contingencies within the REPORTABLE DISTURBANCE period.** Additional contingencies that occur after one minute of the start of a Reportable Disturbance but before the end of the DISTURBANCE RECOVERY PERIOD can be excluded from evaluation. The CONTROL AREA or RESERVE SHARING GROUP shall determine the DCS compliance of the initial REPORTABLE DISTURBANCE by performing a reasonable estimation of the response that would have occurred had the second and subsequent contingencies not occurred.

2.5.3. **Multiple Contingencies within the CONTINGENCY RESERVE RESTORATION PERIOD.** Additional Reportable Disturbances that occur after the end of the DISTURBANCE RECOVERY PERIOD but before the end of the CONTINGENCY RESERVE RESTORATION Period shall be reported and included in the compliance evaluation. However, the CONTROL AREA or RESERVE SHARING GROUP can request a waiver from the Resources Subcommittee for the event if the contingency reserves were rendered inadequate by prior contingencies and a good faith effort to replace contingency reserve can be shown.

3. **Restoration of Reserves.** Each Control Area must fully restore its CONTINGENCY RESERVES within the CONTINGENCY RESERVE RESTORATION PERIOD for its INTERCONNECTION.

3.1. **Start of CONTINGENCY RESERVE RESTORATION PERIOD.** The CONTINGENCY RESERVE RESTORATION PERIOD begins at the end of the DISTURBANCE RECOVERY PERIOD.

3.2. **CONTINGENCY RESERVE RESTORATION PERIOD.** The CONTROL AREA or RESERVE SHARING GROUP shall restore its CONTINGENCY RESERVES within 90 minutes. This period may be adjusted to better suit the reliability targets of the INTERCONNECTION based on analysis approved by the NERC Resources Subcommittee.

4. **Disturbance Control Performance Adjustment.** Each CONTROL AREA or RESERVE SHARING GROUP not meeting the Disturbance Control Standard during a given calendar quarter shall increase its CONTINGENCY RESERVE obligation for the calendar quarter (offset by one month) following the evaluation by the Region and/or the NERC Resources Subcommittee. [e.g. For the first calendar quarter of the year, the penalty is applied for May, June, and July.] The increase shall be directly proportional to the non-compliance with the Disturbance Control Standard in the preceding quarter. This adjustment is not compounded across quarters, and is an additional percentage of reserve needed beyond the MOST SEVERE SINGLE CONTINGENCY. A RESERVE SHARING GROUP may choose an allocation method for increasing its CONTINGENCY RESERVE for the RESERVE SHARING GROUP provided that this increase is fully allocated. [See the “Performance Standard Reference Document,” Section C.]

5. **Reserve Policy Compliance Documentation.** A representative from each CONTROL AREA or RESERVE SHARING GROUP that was non-compliant in the calendar quarter most recently completed shall provide written documentation verifying that the CONTROL AREA or RESERVE SHARING GROUP will apply the appropriate Disturbance Control Performance Adjustment beginning the first day of the succeeding month, and will continue to apply it for three months. The written documentation shall accompany the quarterly Disturbance Control Standard Report when a CONTROL AREA or RESERVE SHARING GROUP is non-compliant.
C. Frequency Response and Bias

[Appendix 1A – The Area Control Error (ACE) Equation]
[Frequency Response Characteristic Survey Training Document]

Requirements

1. **Bias setting review.** Each CONTROL AREA shall review its FREQUENCY BIAS SETTINGS by January 1 of each year and recalculate its setting to reflect any change in area frequency response characteristic.

   1.1. **Bias setting method.** The FREQUENCY BIAS SETTING, and the method used to determine the setting, may be changed whenever any of the factors used to determine the current bias value change.

   1.2. **Bias setting reporting.** Each CONTROL AREA shall report its FREQUENCY BIAS SETTING, and method for determining that setting, to the Performance Subcommittee.

   1.3. **Bias setting verification.** Each CONTROL AREA must be able to demonstrate and verify to the Performance Subcommittee that its FREQUENCY BIAS SETTING closely matches or is greater than its system response.

Standards

1. **Tie-line bias.** Each CONTROL AREA shall operate its AGC on tie-line frequency bias, unless such operation is adverse to system or INTERCONNECTION reliability. The Standards for tie-line bias control follow:

   1.1. **Bias setting to match frequency response.** The CONTROL AREA shall set its frequency bias (expressed in MW/0.1 Hz) as close as practical to the CONTROL AREA's frequency response characteristic. Frequency bias may be calculated several ways:

      1.1.1. **Fixed bias setting.** A fixed frequency bias value may be used which is based on a fixed, straight-line function of tie-line deviation versus frequency deviation. The fixed value shall be determined by observing and averaging the frequency response characteristic for several DISTURBANCES during on-peak hours.

      1.1.2. **Variable bias setting.** A variable (linear or non-linear) bias value may be used which is based on a variable function of tie-line deviation to frequency deviation. The variable frequency bias value shall be determined by analyzing frequency response as it varies with factors such as LOAD, generation, governor characteristics, and frequency.

      1.1.3. **Bias and jointly owned generation.** CONTROL AREAS that use DYNAMIC SCHEDULING or PSEUDO-TIES for jointly owned units must reflect their respective share of the unit governor droop response into their respective FREQUENCY BIAS SETTING. Fixed schedules for JOINTLY OWNED UNITS mandate that the CONTROL AREA (A) that contains the JOINTLY OWNED UNIT must incorporate the respective share of the unit governor response for any CONTROL AREAS that have fixed schedules (B and C). The CONTROL AREAS that have a fixed schedule (B and C) but do not contain the JOINTLY OWNED UNIT.
OWNED UNIT should not include their share of the governor droop response in their FREQUENCY BIAS SETTING.

1.1.4. **Minimum bias setting for CONTROL AREAS that serve native LOAD.** The CONTROL AREA’S monthly average FREQUENCY BIAS SETTING must be at least 1% of the CONTROL AREA’S estimated yearly peak demand per 0.1 Hz change as described in the Frequency Response Characteristic Survey Training Document.

1.1.5. **Minimum bias setting for CONTROL AREAS that do not serve native LOAD.** The CONTROL AREA’S monthly average FREQUENCY BIAS SETTING must be at least 1% of its estimated maximum generation level in the coming year per 0.1 Hz change as described in the Frequency Response Characteristic Survey Training Document.

1.1.6. **Bias and overlap regulation.** A CONTROL AREA that is performing OVERLAP REGULATION SERVICE will increase its FREQUENCY BIAS SETTING to match the frequency response of the entire area being controlled. A CONTROL AREA that is performing SUPPLEMENTAL REGULATION SERVICE shall not change its FREQUENCY BIAS SETTING.

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**Guides**

1. **Governor installation.** Generating units with nameplate ratings of 10 MW or greater should be equipped with governors operational for frequency response unless restricted by regulatory mandates.

2. **Governors free to respond.** Turbine governors and HVDC controls, where applicable, should be allowed to respond to system frequency deviation, unless there is a temporary operating problem.

3. **Governor droop.** All turbine generators equipped with governors should be capable of providing immediate and sustained response to abnormal frequency excursions. Governors should provide a 5% droop characteristic. Governors should, as a minimum, be fully responsive to frequency deviations exceeding ± 0.036 Hz (± 36 mHz).

4. **Governor limits.** Turbine control systems that provide adjustable limits to governor valve movement (valve position limit or equivalent) should not restrict travel more than necessary to coordinate boiler and turbine response characteristics.

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*Graph showing relation between generator output and Interconnection frequency at 0, 50%, and 100% LOAD for a 5% governor droop characteristic.*
D. Time Control Standard

[Appendix 1A — The Area Control Error Equation]
[Appendix 1D — Time Error Correction Procedures]

Introduction

INTERCONNECTION frequency is normally scheduled at 60.00 Hz and controlled to that value. The control is imperfect and over time the frequency will average slightly above or below 60.00 Hz resulting in electric clocks developing an error relative to true time. When the error exceeds pre-set limits, corrective action is taken by adjusting the scheduled frequency, a practice termed Time Error Correction. Each CONTROL AREA shall participate in Interconnection Time Error Correction procedures unless it is operating asynchronously to its INTERCONNECTION.

CONTROL AREAS operating asynchronously may establish their own time error control bands, but must notify the NERC Resources Subcommittee of the bands being utilized, and also provide notification if they are changed.

The Operating Reliability Subcommittee shall designate, on February 1st of each year, a RELIABILITY COORDINATOR to act as the Interconnection Time Monitor to monitor time error for each of the INTERCONNECTIONS and to issue time error correction orders.

Standard

1. Time error correction notice and commencement. Time error corrections shall be conducted in accordance with Appendix 1D, “Time Error Correction Procedure.”

2. Time Error Initiation. Time error corrections will start and end on the hour or half-hour, and notice shall be given at least one hour before the time error correction is to start or stop. All CONTROL AREAS within an INTERCONNECTION shall make all Time Error corrections directed by the Interconnection Time Monitor for its INTERCONNECTION. All CONTROL AREAS within an INTERCONNECTION shall make Time Error Corrections at the same rate.

Requirements

1. Interconnection Time Monitor. Each Interconnection Time Monitor shall monitor time error and shall initiate or terminate corrective action orders according to the procedure specified in Appendix 1D, “Time Error Correction Procedure.”

2. Time Error Correction labeling. Time error correction notifications shall be labeled alphabetically on a monthly basis (A-Z, AA-AZ, BA-BZ,…).

3. Time correction offset. The CONTROL AREA may participate in a Time Error Correction by either of the following two methods:

   1.1. Frequency offset. The Control Area may offset its frequency schedule by 0.02 Hz, leaving the FREQUENCY BIAS SETTING normal, or

   1.2. Schedule offset. If the frequency schedule cannot be offset, the CONTROL AREA may offset its net INTERCHANGE schedule (MW) by an amount equal to the computed bias contribution during a 0.02 Hz frequency deviation (i.e., 20% of the FREQUENCY BIAS SETTING).
D. Time Control Standard

4. **Request for Termination or Halt of Scheduled Time Error Correction.** Any RELIABILITY COORDINATOR in an INTERCONNECTION may request the termination of a time error correction in progress. Any RELIABILITY COORDINATOR may request the halt of a scheduled time error correction that has not begun. CONTROL AREAS that have reliability concerns with the execution of a time error correction shall notify their RELIABILITY COORDINATOR and request the termination of a time error correction in progress. To enable NERC to track the results of the application of procedures relating to Time Control Standards, a RELIABILITY COORDINATOR requesting a termination or halt of a Time Error Correction shall forward an explanation for requesting the termination to the chairman of the Resources Subcommittee within 5 business days.

5. **INTERCONNECTION time error notification.** The INTERCONNECTION Time Monitor shall on the first day of each month issue a notification of time error, accurate to within 0.01 second, to the other RELIABILITY COORDINATORS within the INTERCONNECTION to assure uniform calibration of time standards.

5.1. **Western INTERCONNECTION time error notification.** Within the Western INTERCONNECTION, the RELIABILITY COORDINATOR designated as the Interconnection Time Monitor shall provide the accumulated time error (accurate to within 0.001 second) to all CONTROL AREAS on a daily basis at 1400 PDT/PST using the WSCCNet. The alphabetic designator shall accompany time error notification if a time error correction is in progress.

6. **Time correction on reconnection.** When one or more CONTROL AREAS have been separated from the INTERCONNECTION, upon reconnection, they shall adjust their time error devices to coincide with the time error of the INTERCONNECTION. A notification of the adjustment to time error shall be passed through Time Notification Channels as soon as possible after reconnection.

7. **Leap seconds.** CONTROL AREAS using time error devices that are not capable of automatically adjusting for leap seconds shall arrange to receive advance notice of the leap second and make the necessary manual adjustment in a manner that will not introduce an improper INTERCHANGE SCHEDULE into their control system.
E. Automatic Generation Control Standard

Introduction
CONTROL AREAS utilize AUTOMATIC GENERATION CONTROL (AGC) to automatically direct the loading of REGULATING RESERVE. AGC is used to limit the magnitude of AREA CONTROL ERROR (ACE) variations to the CPS bounds. This section contains Standards that apply to the CONTROL AREA AGC needed to calculate ACE and to routinely deploy the REGULATING RESERVE.

1. CONTROL AREA components. All load, generation, and transmission operating in an INTERCONNECTION must be included within the metered boundaries of a CONTROL AREA.

2. Resource Requirements
2.1. Regulating capability. Each CONTROL AREA shall maintain REGULATING RESERVES that can be controlled by AGC to meet the Control Performance Standard (CPS).

2.2. Regulation Service.
2.2.1. Equipment Requirements. A CONTROL AREA providing REGULATION SERVICE shall ensure that adequate metering, communications and control equipment is employed to prevent such service from becoming a burden on the INTERCONNECTION or other CONTROL AREAS.

2.2.2. Failure Notification. A CONTROL AREA providing REGULATION SERVICE shall notify the host CONTROL AREA for whom it is controlling if it is unable to provide the service, as well as any INTERMEDIARY CONTROL AREAS.

2.2.3. Backup. A CONTROL AREA receiving REGULATION SERVICE shall ensure that backup plans are in place to provide replacement REGULATION SERVICE should the supplying CONTROL AREA no longer be able to provide this service.

3. AUTOMATIC GENERATION CONTROL (AGC).
3.1. AGC calculation. The CONTROL AREA’S AUTOMATIC GENERATION CONTROL (AGC) shall compare total NET ACTUAL INTERCHANGE to total NET SCHEDULED INTERCHANGE plus frequency bias obligation to determine the CONTROL AREA’S AREA CONTROL ERROR (ACE). Single CONTROL AREAS operating asynchronously may employ alternative ACE calculations such as (but not limited to) flat frequency control. If a CONTROL AREA is unable to calculate ACE for more than 30 minutes it shall notify its RELIABILITY COORDINATOR.

3.2. AGC operation. CONTROL AREA AGC shall remain in operation unless such operation adversely impacts the reliability of the INTERCONNECTION.

3.3. Manual control. If AGC has become inoperative, the CONTROL AREA shall use manual control to adjust generation to maintain scheduled INTERCHANGE.

4. Data Requirements.
4.1. Data scan rates for ACE. The Control Area shall ensure that data-acquisition for and calculation of ACE occur at least every six seconds.
4.2. **Frequency.** Each CONTROL AREA shall provide redundant and independent frequency metering equipment that shall automatically activate upon detection of failure of the primary source. This overall installation shall provide a minimum availability of 99.95%.

4.3. **NET SCHEDULED INTERCHANGE.**

4.3.1. **Inclusion of Schedules.** The CONTROL AREA shall include all INTERCHANGE SCHEDULES with ADJACENT CONTROL AREAS in the calculation of NET SCHEDULED INTERCHANGE for the AREA CONTROL ERROR (ACE) equation.

4.3.1.1. CONTROL AREAS with an HVDC link to another CONTROL AREA connected asynchronously to their INTERCONNECTION may choose to omit the INTERCHANGE SCHEDULE related to the HVDC link from the ACE equation if it is modeled as internal generation or load.

4.3.1.2. This standard may not apply to CONTROL AREAS operating asynchronously from their INTERCONNECTION.

4.3.2. **Dynamic Schedules.** The CONTROL AREA shall include all Dynamic Schedules in the calculation of NET SCHEDULED INTERCHANGE for the ACE equation. (See Appendix 1A, “Area Control Error (ACE) Equation”).

4.3.3. **Interchange Ramps.** SCHEDULED INTERCHANGE values used in ACE shall include the effect of ramp rates, which are identical and agreed to between affected CONTROL AREAS. All such calculations shall conform to specifications in Policy 3, “Interchange”, Section C, “Interchange Schedule Standards.”

4.4. **Actual Net Interchange.**

4.4.1. **Tie flows.** All tie-line flows between ADJACENT CONTROL AREAS shall be included in each CONTROL AREA’s ACE calculation.

4.4.2. **Tie-line metering.** CONTROL AREA tie-line MW metering shall be telemetered to both control centers, and shall emanate from a common, agreed-upon source using common primary metering equipment. MWh data shall be telemetered or reported at the end of each hour.

4.4.3. **Data filtering.** The power flow and ACE signals that are utilized for calculation of CONTROL AREA performance or that are transmitted for REGULATION SERVICE shall not be filtered prior to transmission except for anti-aliasing filtering of tie lines.

4.4.4. **Metering for jointly owned generation.** Common metering equipment shall be installed where DYNAMIC SCHEDULES or PSEUDO-TIES are implemented between two or more CONTROL AREAS to deliver the output of JOINTLY OWNED UNITS or to serve remote LOAD.

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1 Interchange is *scheduled* between ADJACENT CONTROL AREAS as explained in the “Interchange Reference Document.” ADJACENT CONTROL AREAS may or may not be *physically* adjacent.

2 Actual Interchange is always measured between PHYSICALLY ADJACENT CONTROL AREAS as explained in the “Interchange Reference Document.”
4.5. **Verification of Tie Flows**

4.5.1. **Hourly verification of tie flows.** Each CONTROL AREA shall perform hourly error checks using tie-line MWh meters with common time synchronization to determine the accuracy of its control equipment.

4.5.2. **Adjustments for equipment error.** The CONTROL AREA shall adjust the component (e.g., tie line meter) of ACE that is in error (if known) or use the interchange meter error (I_{Mt}) term of the ACE equation to compensate for any equipment error until repairs can be made.

4.6. **Data Recording and Display.**

4.6.1. **Minimum data recording.** The CONTROL AREA shall provide its SYSTEM OPERATORS with sufficient instrumentation and data recording equipment to facilitate monitoring of control performance, generation response, and after-the-fact analysis of area performance. As a minimum, the CONTROL AREA must provide its SYSTEM OPERATORS with real-time values for AREA CONTROL ERROR (ACE), INTERCONNECTION frequency and NET ACTUAL INTERCHANGE with each ADJACENT CONTROL AREA.

4.6.2. **Backup power for data recording.** The CONTROL AREA shall provide adequate and reliable backup power supplies and shall periodically test these supplies at the CONTROL AREA’S control center and other critical locations to ensure continuous operation of AGC and vital data recording equipment during loss of the normal power supply.

4.7. **Data Quality.** The CONTROL AREA shall ensure data quality:

4.7.1. **Data Integrity.** Data shall be sampled at least at the same periodicity with which ACE is calculated.

4.7.2. **Missing or bad data.** Missing or bad data shall be flagged for operator display and archival purposes.

4.7.3. **Coincident Data Sampling.** Collected data shall be coincident to the greatest practical extent; i.e., ACE, INTERCONNECTION frequency, net interchange, and other data (see section 4.8.1) shall all be sampled at the same time.

4.7.4. **Data Accuracy.** Control performance and reliable operation is affected by the accuracy of the measuring devices. The required minimum values for measuring devices are listed below:

<table>
<thead>
<tr>
<th>Device</th>
<th>Accuracy</th>
<th>Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>Digital frequency transducer</td>
<td>$\leq 0.001$</td>
<td>Hz</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
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<tr>
<td>MW, MVAR, and voltage transducer</td>
<td>$\leq 0.25$</td>
<td>% of full scale</td>
</tr>
<tr>
<td>Remote terminal unit</td>
<td>$\leq 0.25$</td>
<td>% of full scale</td>
</tr>
<tr>
<td>Potential transformer</td>
<td>$\leq 0.30$</td>
<td></td>
</tr>
<tr>
<td>Current transformer</td>
<td>$\leq 0.50$</td>
<td></td>
</tr>
</tbody>
</table>
4.8. Data Retention.

4.8.1. Performance Standard Data. Each CONTROL AREA shall retain its ACE, actual frequency, SCHEDULED FREQUENCY, NET ACTUAL INTERCHANGE, NET SCHEDULED INTERCHANGE, tie-line meter error correction and FREQUENCY BIAS SETTING data in digital format at the same scan rate at which the data is collected for at least one year.

4.8.2. Disturbance Control Performance Data. Each CONTROL AREA or RESERVE SHARING GROUP shall retain documentation of the magnitude of each REPORTABLE DISTURBANCE as well as the ACE charts and/or samples used to calculate the CONTROL AREA’s or RESERVE SHARING GROUP’s disturbance recovery values. The data shall be retained for one year following the reporting quarter for which the data was recorded.

4.8.3. Data Format. CONTROL AREAS shall be prepared to supply data to NERC in the industry standard format (defined below):

4.8.3.1. CPS source data in daily CSV files with time stamped one minute averages of: 1) ACE and 2) Frequency Deviation from Schedule, will be provided to NERC or the Regions within one week upon request.

4.8.3.2. DCS source data will be supplied in CSV files with time stamped scan rate values for: 1) ACE and 2) Frequency Deviation from Schedule for a time period, from two minute prior to thirty minutes after the identified disturbance, will be provided to NERC or the Regions within one week upon request.

4.8.3.3. Other data (as defined in Requirement 4.8.1, “Performance Standard Data”) may be requested on an ad hoc basis by NERC and the Regions.

4.8.3.4. A sample of the specific file format and naming convention required can be found on the NERC Resources Subcommittee web page.

5. Calibration of measurement devices. Each CONTROL AREA shall at least annually check and calibrate its time error and frequency devices against a common reference.
F. Inadvertent Interchange Standard

Introduction

INADVERTENT INTERCHANGE provides a measure of non-scheduled INTERCHANGE and bilaterally scheduled inadvertent payback. These transfers are caused by such factors as CONTROL AREA regulation and frequency response, metering errors in frequency and/or interchange measurements (either scheduled or actual), unilateral INADVERTENT INTERCHANGE payback and human errors.

The INADVERTENT INTERCHANGE Standard defines a process for monitoring CONTROL AREAS to help ensure that, over the long term, the CONTROL AREAS do not excessively depend on other CONTROL AREAS in the INTERCONNECTION for meeting their demand or INTERCHANGE obligations.

Each CONTROL AREA shall, through daily INTERCHANGE SCHEDULE verification and the use of reliable metering equipment, accurately account for INADVERTENT INTERCHANGE. Each CONTROL AREA shall actively prevent unintentional INADVERTENT INTERCHANGE accumulation due to poor control. Each CONTROL AREA shall also be diligent in reducing accumulated inadvertent balances in accordance with Operating Policies.

Standards

1. INADVERTENT INTERCHANGE calculation. INADVERTENT INTERCHANGE shall be calculated and recorded hourly. INADVERTENT INTERCHANGE may accumulate as energy into or out of the CONTROL AREA.

2. Including all interconnections. Each CONTROL AREA shall include all AC tie lines that connect to its physically ADJACENT CONTROL AREAS in its INADVERTENT INTERCHANGE account. Interchange served through jointly owned facilities must be properly taken into account.

3. Metering requirements. All CONTROL AREA INTERCONNECTION points shall be equipped with common MWh meters, with readings provided hourly to the control centers of both ADJACENT CONTROL AREAS.

4. INADVERTENT INTERCHANGE Accounting. ADJACENT CONTROL AREAS shall operate to a common NET INTERCHANGE SCHEDULE and ACTUAL NET INTERCHANGE value and shall record these hourly quantities, with like values but opposite sign. Each CONTROL AREA shall compute its INADVERTENT INTERCHANGE based on the following:

4.1. Daily accounting. Each CONTROL AREA, by the end of the next business day, shall agree with its adjacent CONTROL AREAS to:

4.1.1. The hourly values of NET INTERCHANGE SCHEDULE.

4.1.2. The hourly integrated MWh values of NET ACTUAL INTERCHANGE

4.2. Monthly accounting. Each CONTROL AREA shall use the agreed-to Daily and Monthly accounting data to compile its monthly accumulated INADVERTENT INTERCHANGE for the On-Peak and Off-Peak hours of the month. [Refer to “Inadvertent Interchange Accounting Training Document”]
4.3. **After-the-Fact Corrections.** After-the-fact corrections to the agreed-to Daily and Monthly accounting data shall only be made to reflect actual operating conditions (e.g. a meter being used for control was sending bad data). Changes or corrections based on non-reliability considerations shall not be reflected in the CONTROL AREA’s INADVERTENT INTERCHANGE. After-the-fact corrections to scheduled or actual values will not be accepted without agreement of the ADJACENT CONTROL AREA(s).

5. **INADVERTENT INTERCHANGE payback.** Each CONTROL AREA shall be diligent in reducing accumulated inadvertent balances. INADVERTENT INTERCHANGE accumulations shall be paid back by either of the following methods:

5.1. **Energy “in-kind” payback.** INADVERTENT INTERCHANGE accumulated during “on-peak” hours shall only be paid back during “on-peak” hours. INADVERTENT INTERCHANGE accumulated during “off-peak” hours shall only be paid back during “off-peak” hours. [See Appendix 1F, “On-Peak and Off-Peak Periods.”]

5.1.1. **Bilateral payback.** INADVERTENT INTERCHANGE accumulations may be paid back via an INTERCHANGE SCHEDULE with another CONTROL AREA. [Refer to Policy 3, “Interchange” for Interchange Scheduling Requirements.]

5.1.1.1. **Opposite balances.** The SOURCE CONTROL AREA and SINK CONTROL AREA must have inadvertent accumulations in the opposite direction.

5.1.1.2. **Agreement on schedule.** The terms of the inadvertent payback INTERCHANGE SCHEDULE shall be agreed upon by all involved CONTROL AREAS and TRANSMISSION PROVIDERS in accordance with NERC operating Policy 3, “Interchange.”

5.1.2. **Unilateral payback.** INADVERTENT INTERCHANGE accumulations may be paid back unilaterally controlling to a target of non-zero ACE. Controlling to a non-zero ACE ensures that the unilateral payback is accounted for in the CPS calculations. The unilateral payback control offset is limited to the CONTROL AREA’s L10 limit and shall not burden the INTERCONNECTION.

5.2. **Other payback methods.** Upon agreement by all REGIONS within an INTERCONNECTION, other methods of INADVERTENT INTERCHANGE payback may be utilized.

6. **INADVERTENT INTERCHANGE summary.** Each CONTROL AREA shall submit a monthly summary of INADVERTENT INTERCHANGE as detailed in Appendix 1F, “Inadvertent Interchange Energy Accounting Practices and Dispute Resolution Process.” These summaries shall not include any after-the-fact changes that were not agreed to by the SOURCE CONTROL AREA, SINK CONTROL AREA and all INTERMEDIARY CONTROL AREA(s).

6.1. **Summary balances.** INADVERTENT INTERCHANGE summaries shall include at least the previous accumulation, net accumulation for the month, and final net accumulation, for both the “on-peak” and “off-peak” periods.

6.2. **Summary submission.** Each CONTROL AREA shall submit its monthly summary report to its Resources Subcommittee Survey Contact by the 15th calendar day of the following month. The Resources Subcommittee Survey Contact will prepare a composite tabulation and submit that tabulation to the NERC staff by the 22nd calendar day of the month.

6.2.1. **Failure to Report.** A CONTROL AREA that neither submits a report nor supplies a reason for not submitting the required data by the 20th calendar day of the following month shall be considered non-compliant.
6.2.2. **Dispute Resolution.** Adjacent CONTROL AREAS that cannot mutually agree upon their respective NET ACTUAL INTERCHANGE or NET SCHEDULED INTERCHANGE quantities by the 15th calendar day of the following month shall, for the purposes of dispute resolution, submit a report to their respective Resources Subcommittee Survey Contact. The report shall describe the nature and the cause of the dispute as well as a process for correcting the discrepancy. The Dispute Resolution Process is described in Appendix 1F, “Inadvertent Interchange Dispute Resolution Process and Error Adjustment Procedures.”
G. Surveys Standard

[Introduction]

Periodic surveys of the control performance of the CONTROL AREAS are conducted to reveal control equipment malfunctions, telemetering errors, improper frequency bias settings, scheduling errors, inadequate generation under automatic control, general control performance deficiencies, or other factors contributing to inadequate control performance.

[Requirements]

1. **On-request Surveys.** Each CONTROL AREA shall perform each of the following surveys, as described in the Performance Standard Reference Document, when called for by the Resources Subcommittee:
   
   1.1. **AIE survey.** Area Interchange Error survey to determine the CONTROL AREAS’ INTERCHANGE error(s) due to equipment failures or improper SCHEDULING operations, or improper AGC performance.
   
   1.2. **FRC survey.** Frequency Response Characteristic survey to determine the CONTROL AREAS’ response to INTERCONNECTION FREQUENCY DEVIATIONS.

2. **Ongoing Surveys.** Each CONTROL AREA shall submit the following surveys on a regular basis as specified below:

   2.1. **CPS, DCS, and FRS Surveys.** Performance Standard surveys to monitor the CONTROL AREAS’ control performance during normal and DISTURBANCE situations.

   2.1.1. **CPS Surveys.** Each CONTROL AREA shall submit a CPS Survey to its Resources Subcommittee Survey Contact no later than the 10th day following the end of the month. The Resources Subcommittee Survey Contact shall submit the CPS survey to NERC no later than the 20th day following the end of the month.

   2.1.2. **DCS Surveys.** Each CONTROL AREA or RESERVE SHARING GROUP shall submit one completed copy of DCS Form, “NERC Control Performance Standard Survey – All Interconnections” to its Resources Subcommittee Survey Contact no later than the 10th day following the end of the calendar quarter (i.e. April 10th, July 10th, October 10th, January 10th). The Resources Subcommittee Survey Contact shall submit the CPS survey to NERC no later than the 20th day following the end of the calendar quarter.

   2.1.3. **FRS Surveys.** Each CONTROL AREA or RESERVE SHARING GROUP shall submit one completed copy of FRS Form, “NERC Frequency Response Standard Survey – All Interconnections” to its Resources Subcommittee Survey Contact no later than the 10th day following the end of the calendar month in which the survey was called. The Resources Subcommittee Survey Contact shall submit the FRS survey to NERC no later than the 20th day of that same month.

[Section 2.1.3 is contingent upon approval of Section C, Version 2.]
2.2. Inadvertent Interchange Summaries (surveys). Each Region shall prepare an Inadvertent Interchange summary monthly to monitor the CONTROL AREAS’ monthly Inadvertent Interchange and all-time accumulated Inadvertent Interchange. Each Region shall submit a monthly accounting to NERC by the 22\textsuperscript{nd} day following the end of the month being summarized.
Policy 2 — Transmission

Policy Subsections
A. Transmission Operations
B. Voltage and Reactive Control

Introduction

This Policy specifies the requirements for operating the transmission system to maintain transmission security. These requirements include transmission operation, establishment of one or more SECURITIES COORDINATORS, and voltage and reactive control.

A. Transmission Operations

[Policy 4B – System Coordination – Operational Security Information]
[Policy 5C – Transmission System Relief]

Standards

1. Basic reliability requirement regarding single contingencies. All CONTROL AREAS shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency.

1.1. Multiple outages. Multiple outages of a credible nature, as specified by Regional policy, shall also be examined and, when practical, the CONTROL AREAS shall operate to protect against instability, uncontrolled separation, or cascading outages resulting from these multiple outages.

1.2. OPERATING SECURITY LIMITS. OPERATING SECURITY LIMITS define the acceptable operating boundaries.

2. Return from OPERATING SECURITY LIMIT Violation. Following a contingency or other event that results in an OPERATING SECURITY LIMIT violation, the CONTROL AREA shall return its transmission system to within OPERATING SECURITY LIMITS soon as possible, but no longer than 30 minutes.

2.1. Reporting Non-compliance Each violation of this Standard shall be reported to the Regional Council and NERC Compliance Subcommittee within 72 hours.

2.2. Reporting format. The report will be submitted on the NERC Preliminary Disturbance Report Form as found in Appendix 5F, “Reporting Requirements for Major Electric System Emergencies.”

Requirements
1. **Policies for dealing with transmission security**CONTROL AREAS, individually and jointly, shall develop, maintain, and implement formal policies and procedures to provide for transmission security. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional security, including:

- Equipment ratings
- Monitoring and controlling voltage levels and real and reactive power flows
- Switching transmission elements
- Planned outages of transmission elements
- Development of Operating Security Limits
- Responding to OPERATING SECURITY LIMIT violations.

1.1. **Responsibility for transmission security**When OPERATING SECURITY LIMIT violations occur, or are expected to occur, the CONTROL AREAS affected by and the CONTROL AREAS contributing to these violations shall implement established joint actions to restore transmission security.

1.2. **Action to keep transmission within limits.**CONTROL AREAS shall take all appropriate action up to and including shedding of firm load in order to comply with Standard 2.A.2.

2. **Security Coordination.** Every Region, subregion, or interregional coordinating group shall establish one or more SECURITY COORDINATORS to continuously assess transmission security and coordinate emergency operations among the CONTROL AREAS within the Subregion, Region, and across the Regional boundaries.

2.1. **TRANSMISSION OPERATING ENTITIES** shall cooperate with their HOST CONTROL AREAS to ensure their operations support the reliability of the INTERCONNECTION.

3. **Coordinating transmission outages.** Planned transmission outages shall be coordinated with any system that operations planning studies show might be affected.
B. Voltage and Reactive Control

Requirements

1. Monitoring and controlling voltage and MVAR flows. Each CONTROL AREA, individually and jointly, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and MVAR flows within its boundaries and with neighboring CONTROL AREAS.

2. Providing reactive resources. Each CONTROL AREA shall supply reactive resources within its boundaries to protect the voltage levels under contingency conditions. This includes the CONTROL AREA’s share of the reactive requirements of interconnecting transmission circuits.

2.1. Providing for reactive requirements. Each PURCHASINGSELLING ENTITY shall arrange for (self-provide or purchase) reactive resources for its reactive requirements.

3. Operating reactive resources. Each CONTROL AREA shall operate their capacitive and inductive reactive resources to maintain system and INTERCONNECTION voltages within established limits.

3.1. Actions. Reactive generation scheduling, transmission line and reactive resource switching, etc., and load shedding, if necessary, shall be implemented to maintain these voltage levels.

3.2. Reactive resources. Each CONTROL AREA shall maintain reactive resources to support its voltage under first contingency conditions.

3.2.1. Location. Reactive resources shall be dispersed and located electrically so that they can be applied effectively and quickly when contingencies occur.

3.2.2. Reactive restoration. Security Limit Violations resulting from reactive resource deficiencies shall be corrected in accordance with Standard 2.A.1 and 2.A.2.

3.3. Field excitation for stability. When a generator’s voltage regulator is out of service, field excitation shall be maintained at a level to maintain Interconnection and generator stability.

4. Operator information. The SYSTEM OPERATOR shall be provided information on all available generation and transmission reactive power resources, including the status of voltage regulators and power system stabilizers.

5. Preventing Voltage Collapse. The SYSTEM OPERATOR shall take corrective action, including load reduction, necessary to prevent voltage collapse when reactive resources are insufficient.

6. Voltage and reactive devices. Devices used to regulate transmission voltage and reactive flow shall be available under the direction of the SYSTEM OPERATOR.
Guides

1. **Keeping lines in service.** Transmission lines should be kept in service as much as possible. They may be removed from service for voltage control only after studies indicate that system reliability will not be degraded below acceptable levels.

2. **Keeping voltage and reactive control devices in service**. Devices used to regulate transmission voltage and reactive flow, including automatic voltage regulators and power system stabilizers on generators and synchronous condensers, should be kept in service as much of the time as possible.

3. **Voltage and reactive devices**. Devices used to regulate transmission voltage and reactive flow should be switchable without de-energizing other facilities.

4. **DC equipment**. Systems with dc transmission facilities should utilize reactive capabilities of converter terminal equipment for voltage control.

5. **Reactive capability testing**. Generating units and other dynamic reactive resources should be tested periodically to determine achievable reactive capability limits.
Policy 3 – Interchange
Version 5.2

[See also, “Interchange Reference Document”]

Policy Subsections
A. Interchange Transaction Implementation
B. Interchange Schedule Implementation
C. Interchange Schedule Standards
D. Interchange Transaction Modifications

Introduction
This Policy addresses the following issues:

- Responsibilities of all PURCHASING-SELLING ENTITIES involved in INTERCHANGE TRANSACTIONS. ¹
- Information requirements for INTERCHANGE TRANSACTIONS.
- Requirements of CONTROL AREAS to assess and confirm INTERCHANGE TRANSACTIONS.
- Accountability of CONTROL AREAS for implementing all INTERCHANGE SCHEDULES in a manner that ensures the reliability of the INTERCONNECTIONS.
- Standards for INTERCHANGE SCHEDULES between CONTROL AREAS.
- Requirements for INTERCHANGE TRANSACTION Cancellation, Termination, and Curtailment.

¹ This Policy deals predominately with INTERCHANGE TRANSACTIONS, that is, those that cross one or more CONTROL AREA boundaries. The more general term “TRANSACTION” includes INTERCHANGE TRANSACTIONS and TRANSACTIONS that are entirely within a CONTROL AREA. At this time, the only reference to the general term “TRANSACTION” is the tagging requirement in Requirement 3.A.2.1.
A. Interchange Transaction Implementation

Introduction

This section specifies the PURCHASING-SELLING ENTITY’s requirements for tagging all INTERCHANGE TRANSACTIONS, the CONTROL AREAS’ and TRANSMISSION PROVIDERS’ obligations for accepting the tags, and CONTROL AREAS’ obligations for implementing the INTERCHANGE TRANSACTIONS. The tag data is integral for providing the CONTROL AREAS, RELIABILITY COORDINATORS, and other operating entities the information they need to assess, confirm, approve or deny, implement, and curtail INTERCHANGE TRANSACTIONS as necessary to accommodate the marketplace and ensure the operational security of the INTERCONNECTION.

Requirements

1. INTERCHANGE TRANSACTION arrangements. The PURCHASING-SELLING ENTITY shall arrange for all Transmission Services, tagging, and contact personnel for each INTERCHANGE TRANSACTION to which it is a party.

   1.1. Transmission services. The PURCHASING-SELLING ENTITY shall arrange the Transmission Services necessary for the receipt, transfer, and delivery of the TRANSACTION.

   1.2. Tagging. The PURCHASING-SELLING ENTITY serving the load shall be responsible for providing the INTERCHANGE TRANSACTION tag. (Note: 1. Any PSE may provide the tag; however, the load-serving PSE is responsible for ensuring that a single tag is provided. 2. If a PSE is not involved in the TRANSACTION, such as delivery from a jointly owned generator, then the SINK CONTROL AREA is responsible for providing the tag. PSEs must provide tags for all INTERCHANGE TRANSACTIONS in accordance with Requirement 2.)

   1.3. Contact personnel. Each PURCHASING-SELLING ENTITY with title to an INTERCHANGE TRANSACTION must have, or arrange to have, personnel directly and immediately available for notification of INTERCHANGE TRANSACTION changes. These personnel shall be available from the time that title to the INTERCHANGE TRANSACTION is acquired until the INTERCHANGE TRANSACTION has been completed.

   1.4. E-Tag monitoring. CONTROL AREAS, TRANSMISSION PROVIDERS, and PURCHASING-SELLING ENTITIES who are responsible for a tagged TRANSACTION shall have facilities to receive unsolicited notification from the Tag Authority of changes in the status of a tag with which the user is a participant.

2. INTERCHANGE TRANSACTION tagging. Each INTERCHANGE TRANSACTION shall be tagged before implementation as required by each INTERCONNECTION as specified in the “E-Tag Spec” or “Transaction Tagging Process within ERCOT Reference Document.” In addition to providing necessary operating information, the INTERCHANGE TRANSACTION tag is the official request from the PURCHASING-SELLING ENTITY to the CONTROL AREAS to implement the INTERCHANGE TRANSACTION. The information that must be provided on the tag is listed in Appendix 3A4.
Policy 3 – Interchange

A. Interchange Transaction Implementation

2.1. Application to Transactions. All INTERCHANGE TRANSACTIONS and certain INTERCHANGE SCHEDULES shall be tagged. In addition, intra-CONTROL AREA transfers using Point-to-Point Transmission Service\(^2\) shall be tagged. This includes:

- INTERCHANGE TRANSACTIONS (those that are between CONTROL AREAS).
- TRANSACTIONS that are entirely within a CONTROL AREA.
- DYNAMIC INTERCHANGE SCHEDULES (tagged at the expected average MW profile for each hour). (Note: a change in the hourly energy profile of 25% or more requires a revised tag.)
- INTERCHANGE TRANSACTIONS for bilateral INADVERTENT INTERCHANGE payback (tagged by the Sink CONTROL AREA).
- INTERCHANGE TRANSACTIONS established to replace unexpected generation loss, such as through prearranged reserve sharing agreements or other arrangements, are exempt from tagging for 60 minutes from the time at which the INTERCHANGE TRANSACTION begins (tagged by the Sink CONTROL AREA). [See also, Policy 1E2 and 2.1, “Disturbance Control Standard”]

2.2. Parties to whom the complete tag is provided. The tag, including all updates and notifications, shall be provided to the following entities:

- Generation Providing Entity
- Generation CONTROL AREA
- TRANSMISSION PROVIDERS
- Transmission Customers
- SCHEDULING ENTITIES
- Intermediate PURCHASING-SELLING ENTITIES (Title-Holders)
- Load CONTROL AREA
- LOAD-SERVING ENTITY
- Market Redispatch Notification Entities (if specified)
- Security Analysis Services

2.3. Method of transmitting the tag. The PURCHASING-SELLING ENTITY shall submit the INTERCHANGE TRANSACTION tag in the format established by each INTERCONNECTION. [“E-Tag Spec” or “Transaction Tagging Process within ERCOT Reference Document”]

2.3.1. Tags for INTERCHANGE TRANSACTIONS that cross INTERCONNECTION boundaries. Procedures are found in Appendix 3A2, “Tagging Across Interconnection Boundaries.”

2.4. INTERCHANGE TRANSACTION submission time. To provide adequate time for INTERCHANGE SCHEDULE implementation, INTERCHANGE TRANSACTIONS shall be submitted as specified in Appendix 3A1, “Tag Submission and Response Timetable.”

\(^2\) This includes all “grandfathered” and other “non-888” Point-to-Point Transmission Service
A. Interchange Transaction Implementation

2.4.1. Exception for security reasons. Exception to the submission time requirements in Section 2.4 is allowed if immediate changes to the INTERCHANGE TRANSACTIONS are required to mitigate an OPERATING SECURITY LIMIT violation. The tag may be submitted after the emergency TRANSACTION has been implemented but no later than 60 minutes.

2.5. Confirmation of tag receipt. Confirmation of tag receipt shall be provided to the PURCHASING-SELLING ENTITY who submitted the tag in accordance with INTERCONNECTION tagging practices. [“E-Tag Spec”]

2.6. Tag acceptance. An INTERCHANGE TRANSACTION tag shall be accepted if all required information is valid and provided in accordance with the tagging specifications in Requirement 2.

3. INTERCHANGE TRANSACTION tag receipt verification. The SINK CONTROL AREA shall verify the receipt of each INTERCHANGE TRANSACTION tag with the TRANSMISSION PROVIDERS, and CONTROL AREAS on the SCHEDULING PATH before the INTERCHANGE TRANSACTION is implemented.

4. INTERCHANGE TRANSACTION assessment. GENERATION PROVIDING ENTITIES, LOAD SERVING ENTITIES, TRANSMISSION PROVIDERS, CONTROL AREAS on the SCHEDULING PATH, and other operating entities responsible for operational security shall be responsible for assessing and “approving” or “denying” INTERCHANGE TRANSACTIONS as requested by PURCHASING-SELLING ENTITIES, based on established reliability criteria and adequacy of INTERCONNECTED OPERATIONS SERVICES and transmission rights as well as the reasonableness of the INTERCHANGE TRANSACTION tag. GENERATION PROVIDING ENTITIES and LOAD SERVING ENTITIES may elect to defer their approval responsibility to their HOST CONTROL AREA. This assessment shall include the following:

The CONTROL AREA assesses:
- TRANSACTION start and end time
- ENERGY PROFILE (ABILITY OF GENERATION MANEUVERABILITY TO ACCOMMODATE)
- SCHEDULING PATH (proper connectivity of ADJACENT CONTROL AREAS)

The TRANSMISSION PROVIDER assesses:
- Valid OASIS reservation number or transmission contract identifier
- Proper transmission priority
- Energy profile accommodation (does energy profile fit OASIS reservation?)
- OASIS reservation accommodation of all INTERCHANGE TRANSACTIONS
- Loss accounting

The GENERATION PROVIDING ENTITY and LOAD-SERVING ENTITY assess:
- Transaction is valid representation of contractually agreed upon energy delivery

4.1. Tag corrections. During the CONTROL AREAS’ and TRANSMISSION PROVIDERS’ assessment time, the PURCHASING-SELLING ENTITY who submitted the tag may elect to submit a tag correction. Tag corrections are changes to an existing tag that do not affect the reliability impacts of the INTERCHANGE TRANSACTION; therefore, tag corrections do not require the complete re-assessment of the tag by all CONTROL AREAS and
A. Interchange Transaction Implementation

TRANSMISSION PROVIDERS on the SCHEDULING PATH, or the completion and submission of a new tag by the PURCHASING-SELLING ENTITY. The SINK CONTROL AREA shall notify all CONTROL AREAS and TRANSMISSION PROVIDERS on the SCHEDULING PATH of the correction, and specifically alert those entities for which a correction has impact. Entities who are impacted by the correction will have an opportunity to reevaluate the tag status. The timing requirements for corrections are found in Appendix 3A1, “Tag Submission and Response Timetable.” Tag items that may be corrected are found in Appendix 3A4, “Required Tag Data.” A description of those entities who may correct an INTERCHANGE TRANSACTION tag is found in Appendix 3D, “Transaction Tag Actions.” [See Appendix 3A1 Subsection C, Interchange Transaction Corrections.]

5. INTERCHANGE TRANSACTION approval or denial. Each CONTROL AREA or TRANSMISSION PROVIDER on the SCHEDULING PATH responsible for assessing and “approving” or “denying” the INTERCHANGE TRANSACTION shall notify the SINK CONTROL AREA. The SINK CONTROL AREA in turn notifies the PURCHASING-SELLING ENTITY who submitted the INTERCHANGE TRANSACTION tag, plus all other CONTROL AREAS and TRANSMISSION PROVIDERS on the SCHEDULING PATH. Assessment timing requirements are found in Appendix 3A1, “Tag Submission and Response Timetable.” A description of those entities who may approve or deny an INTERCHANGE TRANSACTION is found in Appendix 3D, “Transaction Tag Actions.”

5.1. INTERCHANGE TRANSACTION denial. If denied, this notification shall include the reason for the denial.

5.2. INTERCHANGE TRANSACTION approval. The INTERCHANGE TRANSACTION is considered approved if the PURCHASING-SELLING ENTITY who submitted the INTERCHANGE TRANSACTION tag has received confirmation of tag receipt and has not been notified that the transaction is denied.

6. Responsibility for INTERCHANGE TRANSACTION implementation. The SINK CONTROL AREA is responsible for initiating the implementation of each INTERCHANGE TRANSACTION as tagged in accordance with Policy 3.A. Requirement 2 (and its subparts). The INTERCHANGE TRANSACTION is incorporated into the INTERCHANGE SCHEDULE(S) of all CONTROL AREAS on the SCHEDULING PATH in accordance with Policy 3B.

6.1. Tag requirements for INTERCHANGE TRANSACTION implementation. The CONTROL AREA shall implement only those INTERCHANGE TRANSACTIONS that:

- Have been tagged in accordance with Requirement 2 above, or,
- Are exempt from tagging in accordance with Requirement 2.1 above.

7. Tag requirements after curtailment has ended. After the curtailment of a TRANSACTION has ended, the INTERCHANGE TRANSACTION’S energy profile will return to the originally requested level unless otherwise specified by the PURCHASING-SELLING ENTITY. [See Interchange Transaction Reallocation During TLR Levels 3a and 5a Reference Document, Version 1 Draft 6.]

8. Confidentiality of information. RELIABILITY COORDINATORS, CONTROL AREAS, TRANSMISSION PROVIDERS, PURCHASING-SELLING ENTITIES, and entities serving as tag agents or service providers as provided in the “E-Tag Spec” shall not disclose INTERCHANGE TRANSACTION information to any PURCHASING-SELLING ENTITY except as provided for in Requirement 2.2 above, “Parties to whom the complete tag is provided.”
B. Interchange Schedule Implementation


Introduction

This section explains CONTROL AREA requirements for implementing the INTERCHANGE SCHEDULES that result from the INTERCHANGE TRANSACTIONS tagged by the PURCHASING-SELLING ENTITIES in Section A.

Requirements

1. **CONTROL AREAS must be adjacent.** INTERCHANGE SCHEDULES shall only be implemented between ADJACENT CONTROL AREAS.

2. **Sharing INTERCHANGE SCHEDULES details.** The SENDING CONTROL AREA and RECEIVING CONTROL AREA must provide the details of their INTERCHANGE SCHEDULES via the Interregional Security Network as specified in Policy 4.B.

3. **Providing tags for approved TRANSACTIONS to the RELIABILITY COORDINATOR.** The SINK CONTROL AREA shall provide its RELIABILITY COORDINATOR the information from the INTERCHANGE TRANSACTION tag electronically for each Approved INTERCHANGE TRANSACTION.

4. **INTERCHANGE SCHEDULE confirmation and implementation.** The RECEIVING CONTROL AREA is responsible for initiating the confirmation and implementation of the INTERCHANGE SCHEDULE with the SENDING CONTROL AREA.

   4.1. **INTERCHANGE SCHEDULE agreement.** The SENDING CONTROL AREA and RECEIVING CONTROL AREA shall agree with each other on the:
      
      • INTERCHANGE SCHEDULE start and end time
      • Ramp start time and rate
      • Energy profile
      
      This agreement shall be made before either the SENDING CONTROL AREA or RECEIVING CONTROL AREA makes any generation changes to implement the INTERCHANGE SCHEDULE.

      4.1.1. **INTERCHANGE SCHEDULE standards.** The SENDING CONTROL AREA and RECEIVING CONTROL AREA shall comply with the INTERCHANGE SCHEDULE Standards in Policy 3C, “Interchange – Schedule Standards.”

      4.1.2. **Operating reliability criteria.** CONTROL AREAS shall operate such that INTERCHANGE SCHEDULES or schedule changes do not knowingly cause any other systems to violate established operating reliability criteria.

      4.1.3. **DC tie operator.** SENDING CONTROL AREAS and RECEIVING CONTROL AREAS shall coordinate with any DC tie operators on the SCHEDULING PATH.

5. **Maximum scheduled interchange.** The maximum NET INTERCHANGE SCHEDULE between two CONTROL AREAS shall not exceed the lesser of the following:

   5.1. **Total capacity of facilities.** The total capacity of both the owned and arranged-for transmission facilities in service between the two CONTROL AREAS, or
5.2. **Total Transfer Capability.** The established network Total Transfer Capability (TTC) between the CONTROL AREAS, which considers other transmission facilities available to them under specific arrangements, and the overall physical constraints of the transmission network. Total Transfer Capability is defined in *Available Transfer Capability Definitions and Determination*, NERC, June 1996.
C. Interchange Schedule Standards

Standards
1. **INTERCHANGE SCHEDULE start and end time.** INTERCHANGE SCHEDULES shall begin and end at a time agreed to by the SOURCE CONTROL AREA, SINK CONTROL AREA, and the INTERMEDIARY CONTROL AREAS.

2. **Ramp start times.** CONTROL AREAS shall ramp the INTERCHANGE equally across the start and end times of the schedule.

3. **Ramp duration.** CONTROL AREAS shall use the ramp duration established by their INTERCONNECTION as follows unless they agree otherwise:
   3.1. **INTERCHANGE SCHEDULES within the Eastern and ERCOT INTERCONNECTIONS.** ten-minute ramp duration.
   3.2. **INTERCHANGE SCHEDULES within the Western INTERCONNECTION.** 20-minute ramp duration.
   3.3. **INTERCHANGE SCHEDULES that cross an INTERCONNECTION boundary.** The CONTROL AREAS that implement INTERCHANGE SCHEDULES that cross an INTERCONNECTION boundary must use the same start time and ramp durations.
   3.4. **Exceptions for Compliance with Disturbance Control Standard and Line Load Relief.** Ramp durations for INTERCHANGE SCHEDULES implemented for compliance with NERC’s Disturbance Control Standard (recovery from a disturbance condition) and INTERCHANGE TRANSACTION curtailment in response to line loading relief procedures may be shorter, but must be identical for the SENDING CONTROL AREA and RECEIVING CONTROL AREA [See also Policy 1B, “Generation Control Performance – Disturbance Control Standard,” Requirement 2 and subsections on contingency reserve.]

4. **INTERCHANGE SCHEDULE accounting.** Block accounting shall be used.
D. Interchange Transaction Modifications

Introduction
This section specifies PURCHASING-SELLING ENTITY’s, TRANSMISSION PROVIDER’S and CONTROL AREA’s rights and requirements for modifying an INTERCHANGE TRANSACTION tag after it has been approved and implemented as described in the preceding sections.

Requirements
1. INTERCHANGE TRANSACTION modification for market-related issues. The PURCHASING-SELLING ENTITY that submitted an INTERCHANGE TRANSACTION tag may modify an INTERCHANGE TRANSACTION tag that is in progress or scheduled to be started. These modifications may be made due to changes in contracts, economic decisions, or other market-based influences. In cases where a market operator is serving as the source or sink for a TRANSACTION, then they shall have the right to effect changes to the energy flow as well (based on the results of the market clearing).

1.1. Increases. The INTERCHANGE TRANSACTION tag’s energy and/or committed transmission reservation(s) profile may be increased to reflect a desire to flow more energy or commit more transmission than originally requested. Necessary transmission must be either available from the earlier TRANSACTION or provided with the increase.

1.2. Extensions. The INTERCHANGE TRANSACTION tag’s energy profile may be extended to reflect a desire to flow energy during hours not previously specified. Necessary transmission capacity must be provided with the extension.

1.3. Reductions. The INTERCHANGE TRANSACTION tag’s energy and/or committed transmission reservation(s) profile may be reduced to reflect a desire to flow less energy or commit less transmission than originally requested. Reductions are used to indicate cancellations and terminations, as well as partial decreases.

1.4. Combinations of 1.1, 1.2, and 1.3 may be submitted concurrently.

1.5. Coordination responsibilities of the PURCHASING-SELLING ENTITY. The modification must be provided by the PURCHASING-SELLING ENTITY to the following INTERCHANGE TRANSACTION participants:

- GENERATION PROVIDING ENTITY
- Generation CONTROL AREA
- TRANSMISSION PROVIDERS
- TRANSMISSION CUSTOMERS
- SCHEDULING ENTITIES
- Intermediate PURCHASING-SELLING ENTITIES (Title-Holders)
- Load CONTROL AREA
- LOAD-SERVING ENTITY
- Market Redispatch Notification Entities (if specified)
- Security Analysis Services

1.6 INTERCHANGE TRANSACTION modification and evaluation time. To provide adequate time for INTERCHANGE SCHEDULE implementation, INTERCHANGE TRANSACTION
D. Interchange Transaction Modifications

modifications shall be requested and evaluated as specified in Section D of Appendix 3A1, “Tag Submission and Evaluation Timetable.”

2. INTERCHANGE TRANSACTION modification for reliability-related issues. A RELIABILITY COORDINATOR, TRANSMISSION PROVIDER, SCHEDULING ENTITY, GENERATION CONTROL AREA, or LOAD CONTROL AREA may modify an INTERCHANGE TRANSACTION tag that is in progress or scheduled to be started. These modifications may be made only due to TLR events (or other regional congestion management practices), Loss of Generation, or Loss of Load.

2.1. Assignment of coordination responsibilities during TLR events. At such times when TLR is required to ensure reliable operation of the electrical system, and the TLR requires holding or curtailing INTERCHANGE TRANSACTIONS, the LOAD CONTROL AREA is responsible for coordinating the modifications to the appropriate INTERCHANGE TRANSACTION tags. See Policy 9, Appendix 9C1 “Transmission Loading Relief Procedure – Eastern Interconnection.”

2.1.1. Reductions. When a RELIABILITY COORDINATOR must curtail or hold an INTERCHANGE TRANSACTION to respect TRANSMISSION SERVICE reservation priorities or to mitigate potential or actual OPERATING SECURITY LIMIT violations, the RELIABILITY COORDINATOR shall inform the LOAD CONTROL AREA listed on the INTERCHANGE TRANSACTION tag of the greatest reliable level at which the affected INTERCHANGE TRANSACTION may flow.

2.1.2. Reloads. At such time as the TLR event allows for the reloading of the transaction, the RELIABILITY COORDINATOR shall inform the LOAD CONTROL AREA listed on the INTERCHANGE TRANSACTION tag of the releasing of the INTERCHANGE TRANSACTION’S limit.

2.2. Coordination when implementing other congestion management procedures. As a part of some local and regional congestion management and transmission line overload procedures, the TRANSMISSION PROVIDER or SCHEDULING ENTITY is responsible for implementing curtailment of INTERCHANGE TRANSACTIONS. The TRANSMISSION PROVIDER or affected SCHEDULING ENTITY may adjust the INTERCHANGE TRANSACTION tags as required to implement those local and regional congestion management or transmission overload relief procedures that have been approved by the Region(s) or NERC.

2.2.1. Reductions. When a TRANSMISSION PROVIDER or SCHEDULING ENTITY experiences the need to invoke a congestion management or transmission line overload procedure, it may use the curtailment feature of E-Tag to inform the GENERATION CONTROL AREA and the LOAD CONTROL AREA listed on the INTERCHANGE TRANSACTION tag of the greatest reliability limit at which the affected INTERCHANGE TRANSACTION may flow.

2.2.2. Reloads. At such time as the need for the congestion management or transmission line overload relief procedure allows for the full or partial reloading of the transaction, the TRANSMISSION PROVIDER or SCHEDULING ENTITY may use the reload feature of E-Tag to inform the GENERATION CONTROL AREA and the LOAD CONTROL AREA listed on the INTERCHANGE TRANSACTION tag that the INTERCHANGE TRANSACTION’S reliability limit has changed.

2.3. Assignment of coordination responsibilities during a loss of generation. At such times when a loss of generation necessitates curtailing INTERCHANGE TRANSACTIONS,
the Generation CONTROL AREA is responsible for coordinating the modifications to the appropriate INTERCHANGE TRANSACTION tags.

2.3.1. Reductions. When a generation operator experiences a full or partial loss of generation, it shall notify the HOST CONTROL AREA (the GENERATION CONTROL AREA for the INTERCHANGE TRANSACTION). The HOST CONTROL AREA contacts the GENERATION PROVIDING ENTITY that is responsible for the generation. The GENERATION PROVIDING ENTITY determines what schedule modifications need to be made and may request those modifications as market-based reductions, increases, or extensions (either via the tag author, or directly if the entity is the tag author or a market operator). If the GENERATION PROVIDING ENTITY does not resolve the condition, the HOST CONTROL AREA may at its discretion curtail INTERCHANGE TRANSACTIONS associated with the generation.

2.3.2. Reloads. Upon return of the generation, the generator operator shall notify the HOST CONTROL AREA (the GENERATION CONTROL AREA for the INTERCHANGE TRANSACTION). The HOST CONTROL AREA contacts the GENERATION PROVIDING ENTITY that is responsible for the generation. The GENERATION PROVIDING ENTITY determines what schedule modifications need to be made and may request those modifications as market-based reductions, increases, or extensions (either via the tag author, or directly if the entity is the tag author or a market operator). The HOST CONTROL AREA must release the limits previously imposed on INTERCHANGE TRANSACTIONS associated with the generation (but not override any market-based reductions).

2.4. Assignment of coordination responsibilities during a loss of load. At such times when a loss of load necessitates curtailing INTERCHANGE TRANSACTIONS, the LOAD CONTROL AREA is responsible for coordinating the modifications to the appropriate INTERCHANGE TRANSACTION tags.

2.4.1. Reductions. When a LOAD-SERVING ENTITY experiences a loss of load, it shall notify its HOST CONTROL AREA (the LOAD CONTROL AREA for the INTERCHANGE TRANSACTION) and determine what schedule modifications need to be made. The LOAD-SERVING ENTITY may request those modifications as market-based reductions, increases, or extensions (either via the tag author, or directly if the entity is the tag author or a market operator). If the LOAD-SERVING ENTITY does not notify the HOST CONTROL AREA, the HOST CONTROL AREA may at its discretion curtail INTERCHANGE TRANSACTIONS associated with the load.

2.4.2. Reloads. Upon return of the load, THE LOAD-SERVING ENTITY shall notify its HOST CONTROL AREA (the LOAD CONTROL AREA for the INTERCHANGE TRANSACTION) and determine what schedule modifications need to be made. The LOAD-SERVING ENTITY may request those modifications as market-based reductions, increases, or extensions (either via the tag author, or directly if the entity is the tag author or a market operator). If the LOAD-SERVING ENTITY does not notify the HOST CONTROL AREA, the HOST CONTROL AREA must release the limits previously imposed on INTERCHANGE TRANSACTIONS associated with the load (but not override any market-based reductions).

2.5. Coordination responsibilities for reliability-related issues. The modification must be provided by the requesting CONTROL AREA, TRANSMISSION PROVIDER, or SCHEDULING ENTITY to the following INTERCHANGE TRANSACTION participants:
D. Interchange Transaction Modifications

- Generation Providing Entity
- Generation CONTROL AREA
- TRANSMISSION PROVIDERS
- Transmission Customers
- SCHEDULING ENTITIES
- Intermediate PURCHASING-SELLING ENTITIES (Title-holders)
- Load CONTROL AREA
- LOAD-SERVING ENTITY
- Market Redispatch Notification Entities (if specified)
- Security Analysis Services

2.6. **INTERCHANGE TRANSACTION modification and evaluation time.** To provide adequate time for INTERCHANGE SCHEDULE implementation, INTERCHANGE TRANSACTION modifications shall be requested and evaluated as specified in Appendix 3A1, “Tag Submission and Evaluation Timetable.”
Interpretation of Policy 3  
Re: Interchange Transaction Terminations

Summary of the Issue

Tenaska is requesting an interpretation of Policy 3, “Interchange,” with regard to Control Area obligations following the Termination of an Interchange Transaction by a Purchasing-Selling Entity. The following is an excerpt from its letter to NERC (illustration for the example provided by NERC staff):

“It has come to our attention that a serious problem exists with respect to various Control Area operators’ adamant refusal to adjust interchange schedules under NERC policies, and more specifically NERC Operating Policy 3. This problem occurs as a result of Control Areas that are unwilling to reduce an interchange schedule even when they are informed that the generation source for a particular schedule has been lost. In at least one instance, the Control Area operator’s rationale for refusing to adjust the interchange schedule is that NERC policy will not allow such a change. The problem may be best illustrated by the following example:

A marketer purchases capacity and energy from Generator A and contracts to sell such capacity and energy to Load C. Generator A is located in Control Area X and Load C is located in Control Area Z. Control Area X is connected to Control Area Y, which in turn is connected to Control Area Z. The marketer arranges for transmission service with the transmission providers in Control Areas X, Y, and Z in accordance with the transmission providers’ open access transmission tariffs. The marketer then submits an interchange schedule for the next several hours in accordance with NERC policies. At 15 minutes past the top of an hour, Generator A trips. Within two minutes, Generator A notifies Control Area X that it has lost the generation source and that the schedule needs to be adjusted to zero for the remainder of the hour.”

Tenaska then asks the following questions:

1. What should happen next under the NERC policies?
2. Should Control Area X (source Control Area) notify Control Area Z (sink Control Area) that the generator has been lost and that the interchange schedule will be adjusted to zero at a particular time?
3. Should Control Area Z be contacted before Control Area X?
4. Can any of the Control Areas refuse to adjust the schedule upon request?
5. Do NERC policies provide a maximum time for a schedule adjustment?
6. Does a schedule adjustment require a new tag to be submitted?
How Policy 3 Deals with these Issues

The current version of Policy 3 (Version 2a2) Requirement A6 in the NERC Operating Manual refers to Interchange Transaction Cancellations, and, from the context of the Policy, we conclude that a “Cancellation” occurs when a Purchasing-Selling Entity (PSE) must interrupt a Transaction that is in progress:

6. **INTERCHANGE TRANSACTION cancellation.** When a PURCHASING-SELLING ENTITY must cancel an INTERCHANGE TRANSACTION that is in progress, the PURCHASING-SELLING ENTITY shall contact the SINK CONTROL AREA to which it submitted the INTERCHANGE TRANSACTION tag. The SINK CONTROL AREA shall then directly contact the SOURCE CONTROL AREA and its RELIABILITY COORDINATOR. If the SOURCE CONTROL AREA and SINK CONTROL AREA are not adjacent, they then contact their ADJACENT CONTROL AREAS on the SCHEDULING PATH.

The Policy specifies the Control Area notification that must take place, but does not explain what the Control Areas are required to do.

This version of Policy 3 is expected to be replaced on February 15, 2000, with Version 3. Accordingly, this discussion and interpretation will focus on Version 3 of Policy 3.

In Version 3, a PSE’s action to interrupt a Transaction that is underway is defined as a “Termination,” while a “Cancellation” refers to a Transaction that has not yet begun. Transaction Terminations are found in Policy 3, Version 3, Requirement D1:

1. **INTERCHANGE TRANSACTION cancellation and termination.** When a PURCHASING-SELLING ENTITY must terminate an INTERCHANGE TRANSACTION that is in progress, or cancel an INTERCHANGE TRANSACTION that has not started, the PURCHASING-SELLING ENTITY shall contact the SINK CONTROL AREA to which it submitted the INTERCHANGE TRANSACTION tag. The SINK CONTROL AREA shall then directly contact its RELIABILITY COORDINATOR and all INTERMEDIARY CONTROL AREAS and TRANSMISSION PROVIDERS on the SCHEDULING PATH. A description of those entities who may cancel or terminate an Interchange Transaction is found in Appendix 3D, “Transaction Tag Actions.”

This language is almost identical to that in Version 2a2, and neither explains what the Control Areas are expected to do after being notified.

In Section D2, we read that when an Interchange Transaction is *Curtailed* by a Reliability Coordinator:

2. **INTERCHANGE TRANSACTION Curtailments.** When a RELIABILITY COORDINATOR, CONTROL AREA, or TRANSMISSION PROVIDER must curtail or hold an INTERCHANGE TRANSACTION due to loss of generation or load (emphasis added), or to mitigate an OPERATING SECURITY LIMIT violation, it will notify the SINK CONTROL AREA.... And... The SINK CONTROL AREA and SOURCE CONTROL AREA shall then adjust their resulting INTERCHANGE SCHEDULES with their ADJACENT CONTROL AREAS.

Unlike Requirement D1, this Requirement includes the directive that “The Sink Control Area and Source Control Area shall then adjust their resulting Interchange Schedules with their adjacent Control Areas.”

Furthermore, Section 2.2 requires that the Control Areas agree to the time at which the Interchange Schedule adjustment is to take place:

2.2 **INTERCHANGE TRANSACTION curtailment notification.** ...(This notification must include a common time (specified as xxxx hours) at which the curtailment or adjustment is to take place, as well as ramp rates, to avoid affecting INTERCONNECTION frequency and causing INADVERTENT INTERCHANGE.)

Policy 3 does not, however, specify the time to effect the Interchange Schedule changes.

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Approved by:
 Operating Committee: March 30, 2000
Other Agreements and Considerations

When providing an interpretation of Policy 3 regarding Transaction Terminations due to generation loss, it is important to also consider other contracts and agreements that may be in effect. For example, there are most likely contracts between the generation provider and its host Control Area. These contracts probably include agreements on whether energy from the unit will be sold off system, what ancillary services the unit will provide to the Control Area, notification of unit status, MW output, and arrangements for handling unexpected unit output variations or trips. Furthermore, if the merchant is selling its generation to another system, the merchant must arrange for transmission service via the OASIS (including Scheduling, System Control and Dispatch Ancillary service). Control Areas are not free to enter into agreements that conflict with NERC Policies. By the same token, NERC Policies cannot override contractual provisions, at least absent a threat to the reliability of the Interconnection.

Finally, the resulting Transaction must be tagged.

Response to Tenaska’s Request

General Comments

The overall intent of Policy 3 is to

1. Implement the merchants’ Interchange Transactions via Interchange Schedules between Control Areas, and
2. Do so in a manner that ensures reliable operation of the Interconnection.

To accomplish its goals, Policy 3 specifies the obligations of both the Purchasing-Selling Entities and the Control Areas. Just as the Control Areas are required to implement new Interchange Transactions at the request of the Purchasing-Selling Entities, the Control Areas are also obligated to accommodate Interchange Transaction Terminations. This interpretation addresses these obligations. However, some of Tenaska’s questions deal with the timing requirements for Control Area action that are not expressly stated in Policy 3 at present. Answers to these timing issues require development through the Process for Developing and Approving NERC Standards, and this interpretation cannot not address them.

Tenaska’s Questions and NERC’s Answers

1. What should happen next under the NERC policies?
2. Should Control Area X (Source Control Area) notify Control Area Z (Sink Control Area) that the generator has been lost and that the interchange schedule will be adjusted to zero at a particular time?
3. Should Control Area Z be contacted before Control Area X?

These questions will be answered these together:

As Policy 3D1 states, when the merchant must Terminate an Interchange Transaction, he shall contact the Sink Control Area to which he submitted the tag. Policy 3 does not state a time requirement for this notification, but it should be as soon as possible. This interpretation cannot specify a time, because that would be a new Standard.

The Source Control Area is also the Host Control Area for the generator, and NERC assumes that the Source knows of the generation loss via SCADA or other arrangements agreed to by the Generator and Control Area.

As to “What should happen next,” we interpret the intent of Policy 3D1 to be the same as 3D2. The Source and Sink Control Areas must then confirm the Interchange Schedule adjustment that results from the generation loss. They must agree on when the Interchange Schedule adjustment is to begin, and its
ramp rate. It makes no difference whether the source (X) initiates contact with the sink (Z) or vice versa. The Source and Sink Control Areas must then begin to adjust their Interchange Schedules as soon as possible with adjacent Control Areas. Policy 3 does not state how long they have to do this, and we do not believe this interpretation can specify that time—that would be a new Standard. While the PSE who submitted the original tag must now issue a revised tag (or a new one) with the zero energy schedule, the Control Areas should not wait for this tag before adjusting their Interchange Schedules.

4. Can any of the Control Areas refuse to adjust the schedule upon request?

From an operational security standpoint, there is no reason for refusing to adjust its Interchange Schedule for the generation loss. If the adjustment was to cause an Operating Security Limit violation elsewhere, local, Regional, and Interconnection line load relief procedures (e.g., the NERC TLR Procedure) are available to mitigate Operating Security Limit violations by curtailing Interchange Transactions or providing some type of redispach options. Refusing to adjust an Interchange Schedule in order to avoid an Operating Security Limit violation and the initiation of TLR is tantamount to providing a redispach service to maintain existing Interchange Transactions. Unless there is some contract or agreement to provide for this, there is nothing in Policy 3 that would compel a Control Area to refuse to adjust its Interchange Schedule upon the generation loss.

5. Do NERC policies provide a maximum time for a schedule adjustment?

No. However, this interpretation cannot provide that time because that would amount to setting a Standard without using the Procedure for Developing and Approving NERC Standards. The Interconnected Operations Subcommittee is addressing this issue in the next version of Policy 3.

6. Does a schedule adjustment require a new Tag to be submitted?

Yes. Just as a new tag is required for any change in the energy profile. This is especially important for IDC update. However, the Source and Sink Control Areas should not wait to receive the new tag before they adjust their Interchange Schedules with their Adjacent Control Areas. [Also, see Attachment 1, “How E-tag Handles Interchange Transaction Terminations.”]

Further Considerations and Actions Resulting From This Interpretation

1. This interpretation must be ratified by the full Operating Committee because it includes specific directives not expressly stated in the Operating Policies. The Operating Committee may also revise the interpretive statements.

2. These changes shall be posted for public comment in the next version of Policy 3, and no later than November 30, 2000.

3. Tenaska’s letter and this interpretation shall be provided to the Interconnected Operations Services Implementation Task Force to see if any changes in Policy 10 are warranted.
How E-tag Handles Interchange Transaction Terminations

**Under E-Tag 1.4 (current)**
The Authoring PSE may modify a schedule through either cancellation/termination, or through submission of a new tag. If the Authoring PSE wishes to halt a tag prematurely or prior to start, the Authoring PSE must issue a cancellation/termination. If the Authoring PSE further wishes to modify the schedule to run at a different level, the Authoring PSE must then submit a new tag reflecting the modified level. This tag is processed through the normal approval process.

A PSE other than the Tag Author that requires a schedule to be modified must coordinate the implementation of their desire to modify with the Sink Control Area and other participants as specified in Policy 3.

A Control Area or Transmission Provider that requires a schedule to be modified, they must coordinate the implementation of their desire with the Sink Control Area and other participants as specified in Policy 3.

Should the Sink Control Area require a schedule to be modified, they must coordinate the implementation of their desire with the Source Control Area and other participants as specified in Policy 3.

The Sink Control Area is responsible for ensuring that the tag correctly reflects the change in schedule. If the schedule is to be halted prematurely or prior to start, the Sink Control Area is responsible for canceling/terminating the tag. If the schedule is to be run at a different level, the Sink Control Area is responsible for securing from the Authoring PSE a new tag that reflects the modified level.

**Under E-Tag 1.5 (Future)**
The Authoring PSE may modify a schedule through either cancellation/termination, or through submission of a new tag. If the Authoring PSE wishes to halt a tag prematurely or prior to start, the Authoring PSE must issue a cancellation/termination. If the Authoring PSE further wishes to modify the schedule to run at a different level, the Authoring PSE must then submit a new tag reflecting the modified level. This tag is processed through the normal approval process.

A PSE other than the Tag Author that requires a schedule to be modified must coordinate the implementation of their desire to modify with the Sink Control Area and other participants as specified in Policy 3.

A Control Area or Transmission Provider that requires a schedule to be modified, they must coordinate the implementation of their desire with the Sink Control Area and other participants as specified in Policy 3.

Should the Sink Control Area require a schedule to be modified, they must coordinate the implementation of their desire with the Source Control Area and other participants as specified in Policy 3.

The Sink Control Area is responsible for ensuring that the tag correctly reflects the change in schedule through the use of Tag Adjustments. If the tag is to be halted prematurely or prior to start, the Sink Control Area must adjust the Tag to zero for the appropriate hours of the transaction. If a tag is to be modified (equal to or below the original level specified in the transaction), the Sink Control Area must adjust the tag to the appropriate levels for the appropriate hours of the transaction. If the schedule is to be run at a higher level than originally specified, the Sink Control Area is responsible for securing from the Authoring PSE a new tag that reflects the increased level.
Policy 4 — System Coordination

Policy Subsections
A. Monitoring System Conditions
B. Operational Security Information
C. Maintenance Coordination
D. System Protection Coordination

A. Monitoring System Conditions

Requirements
1. Resources. The system operator shall be kept informed of all generation and transmission resources available for use.
2. Transmission status and data. System operators shall monitor transmission line status, MW and MVAR flows, voltage, LTC settings and status of rotating and static reactive resources.
3. Protective relays. Appropriate technical information concerning protective relays shall be available in each system control center.
4. Other information. The system operator shall have information, including weather forecasts and past load patterns, available to predict the system’s near-term load pattern.
5. Monitoring. Monitoring equipment shall be used to bring to the system operator’s attention important deviations in operating conditions and to indicate, if appropriate, the need for corrective action.
   5.1. Metering. Each control area shall use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.
6. System frequency. System operators shall monitor system frequency.

Guides
1. Instrumentation. Reliable instrumentation, including voltage and frequency meters with sufficient range to cover probable contingencies, should be available in each generating plant control room.
2. Recording devices. Automatic oscillographs and other recording devices should be installed at key locations and set to standard time to aid in post-disturbance analysis.
3. Separation. Monitoring should be sufficient, so that in the event of system separation, both the existence of the separation and the boundaries of the separated areas can be determined.
   3.1. Frequency information. Because of possible system separation, frequency information from selected locations should be monitored at the control center.
4. Transmission monitoring. Transmission line monitoring should include a means of evaluating the effects of the loss of any significant transmission or generation facilities, both within and outside the control area.
5. Physical security monitoring. Where practical, critical unmanned facilities should be monitored for physical security.
6. Facility outages. Scheduled outages of generation or transmission facilities should be considered in the monitoring scheme.
Policy 4 – System Coordination
A. Monitoring System Conditions

7. **Voltage coordination.** Voltage schedules should be coordinated from a central location within each control area and coordinated with adjacent control area
B. Operational Security Information


Requirements

1. **Use of Electric System Security Data.** The Electric System Security Data referred to in this Policy and received over the Interregional Security Network shall be used only for operational security analysis and shall not be made available to nor used by PURCHASING-SELLING ENTITIES in the wholesale merchant function.


3. **Data required from Control Areas.** Each CONTROL AREA shall provide its RELIABILITY COORDINATOR(S) with the Electric System Security Data that is necessary to allow THE RELIABILITY COORDINATOR(S) to perform its operational security assessments and coordinate reliable operations.

   3.1. **Data.** CONTROL AREAS shall provide the types of data as listed in Appendix 4B, “Electric System Security Data, Section A, Electric System Security Data”, unless otherwise agreed to by the CONTROL AREAS and their RELIABILITY COORDINATOR(S).

4. **Data exchange among SECURITY COORDINATORS.** Upon request, RELIABILITY COORDINATORS shall, via the ISN, exchange with each other Electric Security Data that is necessary to allow the RELIABILITY COORDINATORS to perform their operational security assessments and coordinate their reliable operations.

   4.1. **Data.** RELIABILITY COORDINATORS shall share with each other the types of data as listed in Appendix 4B, “Electric System Security Data, Section A, Electric System Security Data”, unless otherwise agreed to.

5. **Data exchange among Control Areas.** Upon request, Each CONTROL AREA and other entities shall provide to CONTROL AREAS and other entities with immediate responsibility for operational security, the Electric Security Data that is necessary to allow the CONTROL AREA or other such entity to perform its operational security assessment and to coordinate reliable operations.

   5.1. **Data.** CONTROL AREAS and other entities shall provide the types of data as listed in Appendix 4B, “Electric System Security Data, Section A, Electric System Security Data”, unless otherwise agreed to by the CONTROL AREAS and other entities with immediate responsibility for operational security.

6. **Information from purchasing-selling entities.** PURCHASING-SELLING ENTITIES shall provide information as requested by their host control areas to enable these control areas to conduct operational security assessments and coordinate reliable operations.
C. Maintenance Coordination

Requirements

1. **Generator and transmission outages.** Scheduled generator and transmission outages that may affect the reliability of interconnected operations shall be planned and coordinated among affected systems and control areas. Special attention shall be given to results of pertinent studies.

2. **Voltage regulation equipment.** Scheduled outages of system voltage regulating equipment, such as automatic voltage regulators on generators, supplementary excitation control, synchronous condensers, shunt and series capacitors, reactors, etc., shall be coordinated as required.

3. **Telemetering, control, and communications.** Scheduled outages of telemetering and control equipment and associated communication channels shall be coordinated between the affected areas.
D. System Protection Coordination

Requirements

1. **Protection system familiarity.** System operators shall be familiar with the purpose and limitations of protection system schemes.

2. **Notification of failure and corrective action.** If a protective relay or equipment failure reduces system reliability, the proper personnel shall be notified, and corrective action shall be undertaken as soon as possible.

3. **Coordination when new or changed.** All new protective systems and all protective system changes shall be coordinated among neighboring systems if the new or changed protective systems affect neighboring systems.

4. **Coordination.** Protection systems on major transmission lines and interconnections shall be coordinated with the interconnected systems.

5. **Notification of system changes.** Neighboring systems shall be notified in advance of changes in generating sources, transmission, load, or operating conditions, which could require changes in their protection system.

6. **Monitoring SPS.** The system operator shall monitor the status of each Special Protection System (SPS) and notify all affected systems of each change in status.

Guides

1. **Protection system design.** Protection system design and operations should consider the following:

   1.1. **Minimum complexity.** Protection systems should be of minimum complexity consistent with achieving their purpose.

   1.2. **Redundancy.** Protection systems should have redundancy to allow for their normal maintenance and calibration.

   1.3. **Proper operation.** Protection systems should not normally operate for minor system disturbances, brief overloads, or recoverable system power swings.

   1.4. **High-speed equipment.** High-speed relays, high-speed circuit breakers, and automatic reclosing should be used where studies indicate the application will enhance stability margins. Single-pole tripping or reclosing may be appropriate on some lines.

   1.5. **Automatic reclosing.** Automatic reclosing during out-of-step conditions should be prevented.

   1.6. **Underfrequency relays.** Underfrequency load shedding relays should be coordinated with the generating plant off-frequency relays to assure preservation of system stability and integrity.

   1.7. **Reviewing applications.** Protection system applications, settings, and coordination should be reviewed periodically and whenever major changes in generating resources, transmission, load or operating conditions are anticipated.

   1.8. **Reviewing protection system adequacy and automated monitoring.** Adequacy of protection system communications channels should be reviewed periodically. Automated channel monitoring and failure alarms should be provided for protective system
communications channels, which could cause loss of generation, loss of load, or cascading outages in the event of misoperation or failure.

2. **Protection system implementation, operation, and maintenance.** Each system should implement protection system application, operation, and preventive maintenance procedures, which will enhance their system reliability with the least adverse effect on the Interconnection. These protection system procedures should be provided to all appropriate system personnel and should provide for instruction and training where applicable. Each system should coordinate these procedures with any other systems that could be affected. These procedures should govern:

   2.1. **Planning and application of protection systems.**
   
   2.2. **Review of protection systems and settings.**
   
   2.3. **Intended functioning.** Intended functioning of protection systems under normal, abnormal, and emergency conditions.
   
   2.4. **Testing and maintenance.** Regularly scheduled testing and preventive maintenance of relays, vital system protection equipment, and associated components.

      2.4.1. **Testing under actual conditions.** The operation of the complete protection system should be tested under conditions as close to actual operating conditions as possible, including actual circuit breaker operation where feasible.

      2.4.2. **Testing communications.** Testing protection system communication channels between systems should be coordinated with test results recorded.

   2.5. **Analysis.** Analysis of actual protection system operations.

3. **Reviewing abnormal operation.** A prompt investigation should be made to determine the cause of abnormal protection system performance and correct any deficiencies in the protection scheme.

4. **SPS testing.** SPS should be designed for periodic testing without affecting the integrity of the protected power system. They should normally achieve at least the same high level of reliability as that provided by normal protection systems.

5. **SPS security.** SPS should be designed with inherent security to minimize the probability of an improper operation, even with the failure of a primary component.

6. **SPS application review.** Each SPS should be reviewed frequently to determine if it is still required and will still perform the intended functions. Seasonal changes in power transfers may require changes in the SPS or its relay settings.

7. **SPS operation review.** Each SPS operation should be reviewed and analyzed for correctness.

8. **Correcting improper SPS operation.** Prompt action should be taken to correct the causes of an improper operation.
Policy 5 — Emergency Operations

Policy Subsections

A. Operating Authority Responsibilities
B. Communications and Coordination
C. Capacity and Energy Emergencies
D. Transmission
E. System Restoration
F. Disturbance Reporting
G. Sabotage Reporting

Introduction

Operating emergencies on the BULK ELECTRIC SYSTEM may be minor in nature and require small, real-time system adjustments, or they may be major and require fast, preplanned action to avoid the cascading loss of generation or transmission lines, uncontrolled separation, equipment damage, and interruption of customer service.

The integrity and reliability of the BULK ELECTRIC SYSTEM is of paramount importance, and will take precedence above all other aspects including commercial operations; therefore, all OPERATING AUTHORITIES are expected to cooperate and take appropriate action to mitigate the severity or extent of any system emergency.

Terms

BURDEN. Operation of the BULK ELECTRIC SYSTEM that violates or is expected to violate a SOL or IROL in the INTERCONNECTION or that violates any other NERC, Regional, or local operating reliability policies or standards.

OPERATING AUTHORITY. An entity that:

1. Has ultimate accountability for a defined portion of the BULK ELECTRIC SYSTEM to meet one or more of three reliability objectives – generation/demand balance, transmission reliability, and/or emergency preparedness, and

2. Is accountable to NERC and its Regional Reliability Councils for complying with NERC and Regional Policies, and

3. Has the authority to control or direct the operation of generating resources, transmission facilities, or loads, to meet these Policies.

OPERATING AUTHORITIES include such entities as CONTROL AREAS, generation operators and TRANSMISSION OPERATING ENTITIES; it does not include RELIABILITY COORDINATORS.

OPERATING AUTHORITY AREA. That portion of the BULK ELECTRIC SYSTEM under the purview of the OPERATING AUTHORITY.
A. Operating Authority Responsibilities

Requirements

1. Operating within limits. The OPERATING AUTHORITY shall operate within the SYSTEM OPERATING LIMITS (SOLs) and INTERCONNECTION RELIABILITY OPERATING LIMITS (IROLs).

2. OPERATING AUTHORITY and responsibility. The OPERATING AUTHORITY shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its OPERATING AUTHORITY AREA and shall exercise specific authority to alleviate operating emergencies.

   2.1. Mitigating emergencies. The OPERATING AUTHORITY shall take immediate actions to alleviate operating emergencies including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc.

   2.2. Complying with Reliability Coordinator directives. The OPERATING AUTHORITY shall comply with RELIABILITY COORDINATOR directives unless such actions would violate safety, equipment, or regulatory or statutory requirements. Under these circumstances the OPERATING AUTHORITY must immediately inform the RELIABILITY COORDINATOR of the inability to perform the directive so that the RELIABILITY COORDINATOR can implement alternate remedial actions.

3. Unknown operating states. If the OPERATING AUTHORITY enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes.

4. Information sharing. To facilitate emergency assistance, the OPERATING AUTHORITY shall inform other potentially affected OPERATING AUTHORITIES and its RELIABILITY COORDINATOR of real time or anticipated emergency conditions, and take actions to avoid when possible, or mitigate the emergency.

5. Rendering assistance. The OPERATING AUTHORITY shall render all available emergency assistance requested, provided that the requesting OPERATING AUTHORITY has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements.

6. Keeping facilities in service. The OPERATING AUTHORITY shall not remove BULK ELECTRIC SYSTEM facilities from service if removing those facilities would BURDEN neighboring OPERATING AUTHORITIES unless:

   6.1. The OPERATING AUTHORITY first notifies the adjacent OPERATING AUTHORITIES and coordinates the impact resulting from the removal of the BULK ELECTRIC SYSTEM facility or,

   6.2. When time does not permit such notification and coordination, or when immediate action is required to prevent a hazard to the public, lengthy customer service interruption, or damage to facilities, the OPERATING AUTHORITY shall notify adjacent OPERATING AUTHORITIES at the earliest possible time to ensure OPERATING AUTHORITY coordination.
Policy 5 — Emergency Operations

A. Operating Authority Responsibilities

7. Remaining interconnected. The OPERATING AUTHORITY shall make every effort to remain connected to the INTERCONNECTION. If the OPERATING AUTHORITY determines that by remaining interconnected, it is in imminent danger of violating System Operating Limits or Interconnected Reliability Operating Limits, the OPERATING AUTHORITY may take such actions, as it deems necessary, to protect its OPERATING AUTHORITY AREA.


10. Keeping automatic generation control in service. Each CONTROL AREA shall maintain automatic generation control equipment operational and in service. [See Policy 1E, “Automatic Generation Control Standard”]

11. Taking immediate action. The OPERATING AUTHORITY shall immediately take action to restore the real and reactive power balance. If the OPERATING AUTHORITY is unable to restore its real and reactive power balance it shall request emergency assistance. If corrective actions or emergency assistance is not adequate to mitigate the real and reactive power balance, then the OPERATING AUTHORITY shall implement firm load shedding.

12. Reducing the effects of power flows. The OPERATING AUTHORITY shall immediately reduce the effects of power flows through other OPERATING AUTHORITY AREAS if those flows have been identified as contributing to an operating emergency (e.g., resulting in SOL or IROL violations) in those other OPERATING AUTHORITY AREAS.
B. Communications and Coordination

[Appendix 7A – Instructions for Interregional Emergency Telephone Networks]

Requirements

1. **Communications.** The OPERATING AUTHORITY shall have communications (voice and data links) to appropriate entities within its OPERATING AUTHORITY AREA, which are staffed and available to act in addressing a real time emergency condition.

2. **Notification.** The OPERATING AUTHORITY shall notify its RELIABILITY COORDINATOR and all other potentially affected OPERATING AUTHORITIES through predetermined communication paths of any condition that could threaten the reliability of its OPERATING AUTHORITY AREA.

   2.1. **Using the Interconnection-wide telecommunications system.** When a condition is identified that could threaten the reliability of the INTERCONNECTION or when firm load shedding is anticipated, the affected OPERATING AUTHORITY, via its RELIABILITY COORDINATOR, shall utilize the INTERCONNECTION-wide telecommunications network in accordance with Appendix 7A – Regional and Interregional Telecommunication, Subsection A, “NERC Hotline,” to convey the following information to others in the INTERCONNECTION:

      2.1.1. **Insufficient resources.** The OPERATING AUTHORITY is unable to purchase capacity or energy to meet its demand and reserve requirements on a day-ahead or hour-by-hour basis.

      2.1.2. **IROL violation.** The OPERATING AUTHORITY recognizes that potential or actual line loadings, and voltage or reactive levels are such that a single CONTINGENCY could threaten the reliability of the INTERCONNECTION. (Once a single CONTINGENCY occurs, the OPERATING AUTHORITY must prepare for the next CONTINGENCY.)

      2.1.3. **Implementation of emergency actions.** The OPERATING AUTHORITY anticipates initiating a 3% or greater voltage reduction, public appeals for load curtailments, or firm load shedding for other than local problems.

      2.1.4. **Sabotage incident.** The OPERATING AUTHORITY suspects or has identified a multi-site sabotage occurrence, or single-site sabotage of a critical facility.

   2.2. **Protocols.** The OPERATING AUTHORITY shall issue directives in a clear, concise, definitive manner. The OPERATING AUTHORITY shall receive a response from the person receiving the directive who will repeat the information given. The OPERATING AUTHORITY shall acknowledge the statement as correct or repeat the original statement to resolve misunderstandings.
C. Capacity and Energy Emergencies

[Appendix 5C – Energy Emergency Alerts]

Introduction

During a system emergency, the OPERATING AUTHORITY must continue to comply with NERC Control Performance and Disturbance Control Standards as explained in Policy 1, “Generation Control and Performance,” regardless of costs. In other words, the OPERATING AUTHORITY may not rely on the frequency bias of the other CONTROL AREAS in the INTERCONNECTION to provide energy during the emergency because doing so reduces the INTERCONNECTION’S ability to recover its frequency following additional generator failures.

If the OPERATING AUTHORITY cannot comply with the Control Performance and Disturbance Control Standards, then it must immediately implement remedies to do so. These remedies include, but are not limited to:

1. Requesting assistance from other CONTROL AREAS
2. Declaring an ENERGY EMERGENCY through its RELIABILITY COORDINATOR
3. Reducing load, through procedures such as public appeals, voltage reductions, curtailing interruptible loads and firm loads.

Requirements

1. Anticipating capacity or energy emergency. A CONTROL AREA anticipating an operating capacity or energy emergency shall perform all actions necessary including bringing on all available generation, postponing equipment maintenance, scheduling interchange purchases in advance, and being prepared to reduce firm load.

2. Returning ACE to Acceptable Levels. In the event of a capacity or energy emergency, generation and transmission facilities shall be used to the fullest extent practicable to comply with the CPS and DCS as defined in Policy 1A, “Control Performance Standard.” Using bias variables to “cover up” energy emergency problems is prohibited.

2.1. Mitigating an energy emergency. Once the control areas has exhausted the following steps:

- All available generating capacity is loaded, and
- All operating reserve is utilized, and
- All interruptible load and interruptible exports have been interrupted, and
- All emergency assistance from other control areas is fully utilized, and
- Its ACE is negative and cannot be returned to zero in the next fifteen minutes, then

2.1.1. The CONTROL AREA shall manually shed firm load without delay to return its ACE to zero.
Policy 5 — Emergency Operations

C. Insufficient Generating Capacity

2.1.2. The deficient CONTROL AREA shall declare an EMERGENCY ENERGY Alert in accordance with Appendix 5C.

2.2. **Using INTERCONNECTION’S bias.** The deficient CONTROL AREA may only use the assistance provided by the INTERCONNECTION’S frequency bias for the time needed to implement corrective actions.

3. **Elevating Transmission Service Priority within the Eastern INTERCONNECTION.** When a TRANSMISSION PROVIDER expects to elevate the transmission service priority of an INTERCHANGE TRANSACTION from Priority 6 (Network Integration Transmission Service from Non-designated Resources) to Priority 7 (Network Integration Transmission Service from designated Network Resources) as permitted in its transmission tariff [See Appendix 9C1, “Transmission Loading Relief Procedure” for explanation of Transmission Service Priorities]:

3.1. The LOAD-SERVING ENTITY served by the CONTROL AREA or TRANSMISSION PROVIDER must request its RELIABILITY COORDINATOR to initiate an ENERGY EMERGENCY ALERT. [See Appendix 5C, “Energy Emergency Alerts”]

3.1.1. This Alert must be posted on the NERC Web site, and include the expected total MW that may have its TRANSMISSION SERVICE priority changed.

3.2. EEA 1 will be used to *forecast* the change of the priority of TRANSMISSION SERVICE of an INTERCHANGE TRANSACTION on the system from Priority 6 to Priority 7.

3.3. EEA 2 will be used to *announce* the change of the priority of TRANSMISSION SERVICE of an INTERCHANGE TRANSACTION on the system from Priority 6 to Priority 7.

4. **Unilateral action.** The OPERATING AUTHORITY shall not unilaterally adjust generation in an attempt to return INTERCONNECTION frequency to normal beyond that supplied through frequency bias action and INTERCHANGE SCHEDULE changes. Such unilateral adjustment may overload transmission facilities.
D. Transmission

Introduction

This policy:

1. Summarizes the authority, information and tools required by SYSTEM OPERATORS responsible for the reliability of the INTERCONNECTIONS.

2. Identifies the accountability for developing and implementing procedures to alleviate SYSTEM OPERATING LIMIT (SOL) and INTERCONNECTED RELIABILITY OPERATING LIMIT (IROL) violations.

3. Describes the requirement to develop procedures for the curtailment and restoration of transmission service.

Requirements

1. Mitigating SOL and IROL violations. The OPERATING AUTHORITY experiencing or contributing to an SOL or IROL violation shall take immediate steps to relieve the condition, which may include firm load shedding.

2. OPERATING AUTHORITIES shall not BURDEN others. The OPERATING AUTHORITY shall ensure it operates to prevent the likelihood that a disturbance, action, or non-action will result in a SOL or IROL violation in its OPERATING AUTHORITY AREA or another area of the INTERCONNECTION. In instances where there is a difference in derived operating limits, the BULK ELECTRIC SYSTEM shall always be operated to the most limiting parameter.

3. The OPERATING AUTHORITY shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition persists and equipment is endangered.

4. Neighboring OPERATING AUTHORITIES and RELIABILITY COORDINATORS impacted by the disconnection shall be notified prior to switching, if time permits, otherwise, immediately thereafter.

5. The OPERATING AUTHORITY shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be conducted in all operating timeframes. The OPERATING AUTHORITY shall use the results of these analyses to immediately mitigate the SOL violation.
E. System Restoration

[Introductory Note: This section outlines the procedures for restoring the bulk electric system after a disturbance.]

Introduction

After a system collapse, restoration shall begin when the RELIABILITY COORDINATOR and its affected OPERATING AUTHORITY(IES) determine that they can proceed in an orderly and secure manner. RELIABILITY COORDINATORS and affected OPERATING AUTHORITIES shall coordinate their restoration actions. Restoration priority shall be given to the station supply of power plants and the transmission system. Even though the restoration is to be expeditious, OPERATING AUTHORITIES shall avoid premature action to prevent a re-collapse of the BULK ELECTRIC SYSTEM.

Customer load shall be restored as generation and transmission equipment becomes available, recognizing that load and generation must remain in balance at normal frequency as the BULK ELECTRIC SYSTEM is restored.

Requirements

1. Returning to normal operations. Following a disturbance in which one or more OPERATING AUTHORITY AREAS become isolated, steps shall begin immediately to return the BULK ELECTRIC SYSTEM to normal:

   1.1. Extent of isolated BULK ELECTRIC SYSTEM. The OPERATING AUTHORITY working in conjunction with its RELIABILITY COORDINATOR shall determine the extent and condition of the isolated area(s).

   1.2. Frequency restoration. The OPERATING AUTHORITY shall then take the necessary action to restore BULK ELECTRIC SYSTEM frequency to normal, including adjusting generation, placing additional generators on line, or load shedding.

   1.3. INTERCHANGE SCHEDULE review. The RELIABILITY COORDINATOR and affected CONTROL AREAS shall immediately review the INTERCHANGE SCHEDULES between those CONTROL AREAS or fragments of those CONTROL AREAS within the separated area and make adjustments as needed to facilitate the restoration. The affected Control Areas shall make all attempts to maintain the adjusted INTERCHANGE SCHEDULES whether generation control is manual or automatic.

   1.4. Resynchronizing. When voltage, frequency, and phase angle permit, the OPERATING AUTHORITY may resynchronize the isolated area(s) with the surrounding area(s), upon notifying its RELIABILITY COORDINATOR and adjacent OPERATING AUTHORITIES, and considering the size of the area being reconnected and the capacity of the transmission lines effecting the reconnection. (The OPERATING AUTHORITY’S restoration plan should consider the number of synchronizing points across the system.)

   1.5. Off-site supply for nuclear plants. The OPERATING AUTHORITY shall give high priority to restoration of off-site power to nuclear stations.

   1.6. Load Shedding. Load shall be shed in neighboring OPERATING AUTHORITY areas, where required, to permit successful interconnected system restoration.
F. Disturbance Reporting

[Appendix 5F – Reporting Requirements for Major Electric System Emergencies]

Introduction

Disturbances or unusual occurrences that jeopardize the operation of the BULK ELECTRIC SYSTEM, and result, or could result, in system equipment damage, or customer interruptions, must be studied in sufficient depth to increase industry knowledge of electrical interconnection mechanics to minimize the likelihood of similar events in the future. It is important that the facts surrounding a disturbance shall be made available to RELIABILITY COORDINATORS, and OPERATING AUTHORITIES, Regional Councils, NERC, and regulatory agencies entitled to the information.

Requirements

1. **Regional Council Reporting Procedures.** Each Regional Council shall establish and maintain a Regional reporting procedure to facilitate preparation of preliminary and final disturbance reports.

2. **Analyzing disturbances.** BULK ELECTRIC SYSTEM disturbances shall be promptly analyzed by the affected OPERATING AUTHORITIES.

3. **Disturbance reports.** Based on the NERC and DOE disturbance reporting requirements, those OPERATING AUTHORITIES responsible for investigating the incident shall provide a preliminary written report to their Regional Council and NERC.
   
   3.1. **Preliminary written reports.** Either a copy of the report submitted to DOE, or, if no DOE report is required, a copy of the NERC Interconnected Reliability Operating Limit and Preliminary Disturbance Report form shall be submitted by the affected OPERATING AUTHORITY within 24 hours of the disturbance or unusual occurrence. Certain events (e.g. near misses) may not be identified until some time after they occur. Events such as these should be reported within 24 hours of being recognized.

   3.2. **Preliminary reporting during adverse conditions.** Under certain adverse conditions, e.g. severe weather, it may not be possible to assess the damage caused by a disturbance and issue a written Interconnected Reliability Operating Limit and Preliminary Disturbance Report within 24 hours. In such cases, the affected OPERATING AUTHORITY shall notify its Regional Council(s) and NERC promptly and verbally provide as much information as is available at that time. The affected OPERATING AUTHORITY shall then provide timely, periodic verbal updates until adequate information is available to issue a written Preliminary Disturbance Report.

   3.3. **Final written reports.** If in the judgment of the Regional Council, after consultation with the OPERATING AUTHORITY in which a disturbance occurred, a final report is required, the affected OPERATING AUTHORITY shall prepare this report within 60 days. As a minimum, the final report shall have a discussion of the events and its cause, the conclusions reached, and recommendations to prevent recurrence of this type of event. The report shall be subject to Regional Council approval.

4. **Notifying NERC.** The NERC Disturbance Reporting Requirements, shown in Appendix 5F, Sections A and B, are the minimum requirements for reporting disturbances, unusual occurrences, and voltage excursions to NERC.
F. Disturbance Reporting

5. **Notifying DOE.** The U.S. Department of Energy’s most recent Emergency Incident and Disturbance Reporting Requirements, outlined in Appendix 5F, Section C, are the minimum requirements for U.S. utilities and other entities subject to Section 13(b) of the Federal Energy Administration Act of 1974. Copies of these reports shall be submitted to NERC at the same time they are submitted to DOE.

6. **Assistance from NERC Operating Committee (OC) and the Disturbance Analysis Working Group (DAWG).** When a BULK ELECTRIC SYSTEM disturbance occurs, the Regional Council’s OC and DAWG representatives shall make themselves available to the OPERATING AUTHORITY immediately affected to provide any needed assistance in the investigation and to assist in the preparation of a final report.

7. **Final report recommendations.** The Regional Council shall track and review the status of all final report recommendations at least twice each year to ensure they are being acted upon in a timely manner. If any recommendation has not been acted on within two years, or if Regional Council tracking and review indicates at any time that any recommendation is not being acted on with sufficient diligence, the Regional Council shall notify the NERC Planning Committee and Operating Committee of the status of the recommendation(s) and the steps the Regional Council has taken to accelerate implementation.
G. Sabotage Reporting

Introduction

Disturbances or unusual occurrences, suspected or determined to be caused by sabotage, shall be reported to the appropriate systems, governmental agencies, and regulatory bodies.

Requirements

1. Recognizing sabotage. Each OPERATING AUTHORITY shall have procedures for the recognition of and for making its SYSTEM OPERATORS aware of sabotage events on its facilities and multi-site sabotage affecting larger portions of the INTERCONNECTION. Procedures shall also be established for the communication of information concerning sabotage events to appropriate parties in the INTERCONNECTION.

2. Reporting guidelines. SYSTEM OPERATORS shall be provided with guidelines including lists of utility contact personnel, for reporting disturbances due to sabotage events.

3. Contact with FBI and RCMP. OPERATING AUTHORITIES shall establish communications contacts with local Federal Bureau of Investigation (FBI) or Royal Canadian Mounted Police (RCMP) officials and develop reporting procedures as appropriate to their circumstances.

Guides

1. Information to media. OPERATING AUTHORITIES should establish procedures for supplying sabotage-related information to the media. Release of this information must be coordinated with the appropriate FBI or RCMP personnel.
Policy 6 – Operations Planning

Policy Subsections

A. Normal Operations
B. Emergency Operations
C. Load Shedding
D. System Restoration
E. Continuity of Operations

Introduction

Each OPERATING AUTHORITY shall maintain a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each OPERATING AUTHORITY is responsible for using available personnel and system equipment to implement these plans to assure that interconnected systems reliability will be maintained.

SYSTEM OPERATORS shall participate in the system planning and design study processes so that these studies will contain the SYSTEM OPERATORS’ perspective and the SYSTEM OPERATORS will know the intended planning purpose.
A. Normal Operations

Requirements

1. **Operations planning coordination.** Each OPERATING AUTHORITY shall plan its current-day, next-day, and seasonal operations in coordination with neighboring OPERATING AUTHORITIES so that normal INTERCONNECTION operation will proceed in an orderly and consistent manner.

   1.1. Each transmission and generation owner shall coordinate its current-day, next-day, and seasonal operations with its host CONTROL AREA(s).

   1.2. Each CONTROL AREA shall coordinate its current-day, next-day, and seasonal operations with neighboring CONTROL AREAS and with its RELIABILITY COORDINATOR.

2. **Operations planning objectives.** Each OPERATING AUTHORITY shall plan to meet:

   2.1. Planned changes in system configuration, generation dispatch, interchange scheduling and demand patterns.

   2.2. Unplanned changes in system configuration and generation dispatch (at a minimum N-1 CONTINGENCY planning) in accordance with NERC, Regional, and local reliability requirements.

   2.3. Capacity and energy reserve requirements, including the deliverability/capability for any single CONTINGENCY.

   2.4. Voltage and/or reactive limits, including the deliverability/capability for any single CONTINGENCY.

   2.5. INTERCHANGE SCHEDULES. All generator owners shall operate their plant so as to adhere to ramp schedules.

   2.6. **SYSTEM OPERATING LIMITS.**

3. **BULK ELECTRIC SYSTEM studies.** The CONTROL AREA shall perform seasonal, next-day, and current-day BULK ELECTRIC SYSTEM studies to determine **SYSTEM OPERATING LIMITS.**

   Neighboring CONTROL AREAS shall utilize identical SYSTEM OPERATING LIMITS for common facilities. These BULK ELECTRIC SYSTEM studies shall be updated as necessary to reflect current system conditions. The results of BULK ELECTRIC SYSTEM studies shall be made available to the CONTROL AREA operators and to its RELIABILITY COORDINATOR.

4. **Total Transfer Capability or Available Transfer Capability and transmission coordination.**

   The CONTROL AREA shall include known SOLs or IROLs within its area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs and/or regional TTC/ATC calculation processes.

5. **Generator capability.** At the request of the CONTROL AREA, generator operators shall perform generating capability verification that shall include, among other variables, weather, ambient air and water conditions, and fuel quality and quantity, and provide the results to the CONTROL AREA operator as requested. (See also Planning Standard II.B.S1)
6. **Communication of facility status.** (Note: in the following Requirements, the term “immediately” shall be defined as “without any intentional time delay.”)

6.1. Generator operators shall immediately notify their CONTROL AREA operators of changes in capabilities and characteristics including but not limited to:

6.1.1. Changes in real and reactive output capabilities,

6.1.2. Automatic Voltage Regulator status and mode setting

6.2. Generation operators shall provide a forecast of expected real power output to their CONTROL AREAS to assist in operations planning at the CONTROL AREA’S request (e.g. a seven-day forecast of real output).

6.3. Transmission operators shall immediately notify their CONTROL AREA operators of changes in capabilities and characteristics including but not limited to:

6.3.1. Changes in transmission facility status

6.3.2. Changes in transmission facility rating

6.4. CONTROL AREA shall immediately communicate the above information to their RELIABILITY COORDINATOR.

6.5. **Uniform line identifiers.** Neighboring OPERATING AUTHORITIES shall use uniform line identifiers when referring to transmission facilities of an interconnected network.

7. **Computer models.** The CONTROL AREA shall maintain accurate computer models utilized for analyzing and planning system operations.
B. Emergency Operations

Introduction
Each OPERATING AUTHORITY shall develop, maintain, and implement a set of plans consistent with NERC Operating Policies to mitigate operating emergencies. These plans shall be coordinated with other OPERATING AUTHORITIES, CONTROL AREAS, and RELIABILITY COORDINATORS as appropriate.

Requirements

1. Agreements for emergency assistance. CONTROL AREAS shall have operating agreements with adjacent CONTROL AREAS that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote CONTROL AREAS.

2. Staffing and training. The CONTROL AREA shall be staffed with adequately trained operating personnel. Training for operators shall meet or exceed a minimum of 5 days per year of training and drills using realistic simulations of system emergencies, in addition to other training required to maintain qualified operating personnel.

3. Load shedding to prevent separation. The OPERATING AUTHORITY shall have an emergency load reduction plan for all identified IROLs. The plan shall include the details on how the OPERATING AUTHORITY will implement load reduction in sufficient amount and time to mitigate the IROL violation before system separation or collapse would occur. The load reduction plan must be capable of being implemented within 30 minutes.

4. Emergency plan types. The OPERATING AUTHORITY shall have emergency plans that address the following:

   4.1. Insufficient Generating Capacity

   4.2. Transmission

   4.3. Load Shedding

   4.4. System Restoration

5. Emergency plan elements. Each CONTROL AREA shall have emergency plans that will enable it to mitigate operating emergencies. At a minimum, the CONTROL AREA’S emergency plans shall include:

   5.1. Communications. Communications protocols to be used during emergencies.

   5.2. Controlling Actions. List of controlling actions to resolve the emergency. Load reduction, in sufficient quantity to resolve the emergency within NERC established timelines, shall be one of the controlling actions.

   5.3. Coordinating Tasks. The tasks to be coordinated with and among adjacent CONTROL AREAS and OPERATING AUTHORITIES within the CONTROL AREA.

   5.4. Staffing. Staffing levels for the emergency.

6. Emergency plan review and update. The OPERATING AUTHORITY shall annually review and update each emergency plan. The OPERATING AUTHORITY shall provide a copy of its updated
emergency plans to neighboring OPERATING AUTHORITIES and to its RELIABILITY COORDINATOR.

7. **Emergency Plan Coordination.** The OPERATING AUTHORITY shall coordinate its emergency plans with other OPERATING AUTHORITIES, CONTROL AREAS, and RELIABILITY COORDINATORS as appropriate. This coordination includes the following steps:

7.1. **Communications.** Establish and maintain reliable communications between interconnected systems.

7.2. **Interchange agreements.** Arrange new interchange agreements to provide for emergency capacity or energy transfers if existing agreements cannot be used.

7.3. **Maintenance coordination.** Coordinate transmission and generator maintenance schedules to maximize capacity or conserve the fuel in short supply. (This includes water for hydro generators.)

7.4. **Energy deliveries.** Arrange deliveries of electrical energy or fuel from remote systems through normal operating channels.

**Guides**

Emergency plans should consider the following items:

1. **Fuel supply and inventory.** An adequate fuel supply and inventory plan which recognizes reasonable delays or problems in the delivery or production of fuel.

2. **Fuel switching.** Fuel switching plans for units for which fuel supply shortages may occur, e.g., gas and light oil.

3. **Environmental constraints.** Plans to seek removal of environmental constraints for generating units and plants.

4. **System energy use.** The reduction of the system’s own energy use to a minimum.

5. **Public appeals.** Appeals to the public through all media for voluntary load reductions and energy conservation including educational messages on how to accomplish such load reduction and conservation.

6. **Load management.** Implementation of load management and voltage reductions, if appropriate.

7. **Optimize fuel supply.** The operation of all generating sources to optimize the availability.

8. ** Appeals to customers to use alternate fuels.** In a fuel emergency, appeals to large industrial and commercial customers to reduce non-essential energy use and maximize the use of customer-owned generation that rely on fuels other than the one in short supply.

9. **Interruptible and curtailable loads.** Use of interruptible and curtailable customer load to reduce capacity requirements or to conserve the fuel in short supply.
10. **Maximizing generator output and availability.** The operation of all generating sources to maximize output and availability. This should include plans to winterize units and plants during extreme cold weather.

11. **Notifying IPPs.** Notification of cogeneration and independent power producers to maximize output and availability.

12. **Requests of government.** Requests to appropriate government agencies to implement programs to achieve necessary energy reductions.

13. **Load curtailment.** A mandatory load curtailment plan to use as a last resort. This plan should address the needs of critical loads essential to the health, safety, and welfare of the community. Address firm load curtailment.

14. **Notification of government agencies.** Notification of appropriate government agencies as the various steps of the emergency plan are implemented.

15. **Utilization of Energy Emergency Alert procedures as specified in Appendix 5C.**

16. **Generation redispatch options.**

17. **Transmission reconfiguration options.**

18. **Utilization of Special Protection Schemes.**

19. **Local or INTERCONNECTION-wide transmission loading relief procedures.**

20. **Reserve sharing.**
C. Load Shedding

Introduction
After taking all other remedial steps, an OPERATING AUTHORITY or CONTROL AREA whose integrity is in jeopardy due to insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the INTERCONNECTION.

Requirements
   1.1. Coordination. Load shedding plans shall be coordinated among the interconnected OPERATING AUTHORITY AREAS.
   1.2. Frequency or voltage level. Automatic load shedding shall be initiated at the time the system frequency or voltage has declined to an agreed-to level.
      1.2.1. Load shedding steps. Automatic load shedding shall be in steps related to one or more of the following: frequency, rate of frequency decay, voltage level, rate of voltage decay or power flow levels.
      1.2.2. Minimizing risk. The load shed in each step shall be established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.
      1.2.3. Underfrequency load shedding on separation. After an OPERATING AUTHORITY AREA or CONTROL AREA separates from the INTERCONNECTION, if there is insufficient generating capacity to restore system frequency following automatic underfrequency load shedding, the OPERATING AUTHORITY or CONTROL AREA shall shed additional load.
      1.2.4. Coordination with generator, et al, tripping. Automatic load shedding shall be coordinated throughout the OPERATING AUTHORITY AREAS with underfrequency isolation of generating units, tripping of shunt capacitors, and other automatic actions which will occur under abnormal frequency, voltage, or power flow conditions.

2. Plans for manual load shedding. Each OPERATING AUTHORITY or CONTROL AREA shall have plans for SYSTEM OPERATOR-controlled manual load shedding to respond to real-time emergencies. The manual load shedding shall be capable of being implemented in a timeframe to adequately respond to the emergency.

Guides
1. Load shedding studies. Automatic load shedding plans should be based on studies of system dynamic performance, simulating the greatest probable imbalance between load and generation.
   1.1. Unacceptable results. Plans to shed load automatically should be examined to determine if unacceptable overfrequency, overvoltage, or transmission overloads might result.
C. Load Shedding

1.1.1. **Action on overfrequency.** If overfrequency is likely, the amount of load shed should be reduced or automatic overfrequency load restoration should be provided.

1.1.2. **Action on overvoltage.** If overvoltages are likely, the load-shedding program should be modified to minimize that probability.

2. **Local area considerations.** When scheduling load to be shed automatically, the system should consider its local area requirements and transmission capabilities between areas.

3. **Automatic isolation plan.** A generation-deficient CONTROL AREA may establish an automatic isolation plan in lieu of automatic load shedding, if by doing so it removes the BURDEN it has imposed on the INTERCONNECTION. This isolation plan may be used only with the consent of neighboring systems, and if it leaves the remaining BULK ELECTRIC SYSTEM intact.
D. System Restoration

[Policy 5E – Emergency Operations–System Restoration]
[Electric System Restoration Reference Document]

Introduction

Each OPERATING AUTHORITY shall have and periodically update a logical plan to reestablish its electric system in a stable and orderly manner in the event of a partial or total shutdown of the system. This plan shall be coordinated with other OPERATING AUTHORITIES in the INTERCONNECTION to assure a consistent INTERCONNECTION restoration plan.

A reliable and adequate source of startup power for generating units shall be provided. Where sources are remote from the generating unit, instructions shall be issued to expedite availability. Generation restoration steps shall be verified by actual testing whenever possible.

System restoration procedures shall be verified by actual testing or by simulation.

Requirements

1. Restoration plan. Each OPERATING AUTHORITY shall have a restoration plan with necessary operating instructions and procedures to cover emergency conditions, including the loss of vital telecommunications channels.

   1.1. Restoration plan update. The OPERATING AUTHORITY shall review and update its restoration plan at least annually, and whenever it makes changes in the power system network, and to correct deficiencies found during the simulated restoration exercises.

   1.2. Restoring the INTERCONNECTION. The OPERATING AUTHORITY’S restoration plans must be developed with the intent of restoring the integrity of the INTERCONNECTION.

   1.3. Coordination. The OPERATING AUTHORITY shall coordinate its restoration plans with neighboring OPERATING AUTHORITIES.

   1.4. Testing telecommunications. The OPERATING AUTHORITY will periodically test its telecommunication facilities needed to implement the restoration plan.

2. SYSTEM OPERATOR training. The OPERATING AUTHORITY shall train its operating personnel in the implementation of the restoration plan. Such training shall include simulated exercises, if practicable.

3. Procedure testing. The OPERATING AUTHORITY shall verify its restoration procedures by actual testing or by simulation.

4. Blackstart capability. The OPERATING AUTHORITY shall ensure the availability and location of Blackstart capability within its OPERATING AUTHORITY AREA to meet the needs of the restoration plan.

Guides

1. Operation at abnormal voltage and frequency. Generators and their auxiliaries should be able to operate reliably at abnormal voltages and frequencies.
Policy 6 – Operations Planning

D. System Restoration

2. **Generator shutdown and restart.** Emergency sources of power should be available to facilitate safe shutdown, enable turning gear operation, minimize the likelihood of damage to either generating units or their auxiliaries, maintain communications, and expedite restarting.

3. **Emergency power source.** Each generating plant should have a source of emergency power to expedite restarting.
   
   3.1. Hydroelectric plants should have internal provisions for restarting.
   
   3.2. Station service busses. Where station service generators are used in parallel with the system, station auxiliary busses should be separated automatically from the system before the frequency has decayed sufficiently to adversely affect the station service units.
   
   3.3. Station service and area security. The effect of station service generators on area security should be considered before they are shut down for economy.
   
   3.4. Outside startup power source. Where an outside source of power is necessary for generating unit startup, switching procedures should be prearranged and periodically reviewed with SYSTEM OPERATORS and other operating personnel.

4. **Startup and shutdown plans.** Each CONTROL AREA should have written plans for orderly startup and shutdown of the generating units.
   
   4.1. Updates. These plans should be updated when required.
   
   4.2. Drills. Drills should be held periodically to assure that plant operators are familiar with the plans.

5. **Blackstart testing.** Periodic tests should be made to verify blackstart capability.

6. **Synchronoscope calibration.** All synchronoscopes should be calibrated in degrees, and phase angle differences at interconnection points should be communicated in degrees.

7. **Synchronizing locations and procedures.** SYSTEM OPERATORS should know the preplanned synchronizing locations and procedures. Procedures should provide for alternative action to be taken in case of lack of information or loss of communication channels that would affect resynchronizing.

8. **Protection systems.** Proper protection systems should be considered in the restoration sequence. Relay polarization sources should be maintained during the process.

9. **Telecommunications considerations.** Backup voice telecommunications facilities, including emergency power supplies and alternate telecommunications channels, should be provided to assure coordinated control of operations during the restoration process.

10. **Master trip points.** Control centers using SCADA systems should consider providing master trip points for each station to expedite the restoration process.
E. Continuity of Operations

[Backup Control Center Reference Document]

Requirement

CONTROL AREAS and RELIABILITY COORDINATORS shall have a plan to continue reliability operations in the event its control center becomes inoperable.

Guides

1. Must not BURDEN the INTERCONNECTION. The standards of Policy 1, “Generation Control and Performance,” should be considered when developing the plan to continue operation so that the CONTROL AREA will not be a BURDEN to the INTERCONNECTION if its own control center becomes inoperable.

1.1. Location of backup center. If the CONTROL AREA has a backup control center, it should be remote from the primary control center site.
Policy 7 — Telecommunications

Policy Subsections

A. Facilities
B. System Operator Telecommunication Procedures
C. Loss of Telecommunications
D. Security

A. Facilities

Requirements

1. Reliable and Secure Telecommunications Networks. Each Participating Entity\(^1\) shall provide adequate and reliable telecommunications facilities\(^2\) internally and with other Participating Entities to assure the exchange of INTERCONNECTION and operating information necessary to maintain reliability. Where applicable, these facilities shall be redundant and diversely routed. Adequacy, redundancy, reliability and applicability are determined by each application’s requirements.

2. Interregional Security Network. All RELIABILITY AREAS and Participating Entities shall participate in the Interregional Security Network as described in Appendix 7A, Section B, “Interregional Security Network,” and provide the Operational Security Information as explained in Policy 4B, “Required Data Exchange.”

3. Reliability of Telecommunications Facilities. Vital telecommunications facilities shall be managed, alarmed, tested and/or actively monitored. Special attention shall be given to emergency telecommunications facilities and equipment not used for routine communications.

B. System Operator Telecommunication Procedures

Requirements

1. Telecommunications coordination. Each Participating Entity shall provide a means to coordinate telecommunications among the systems in that area. This coordination shall include the ability to investigate and recommend solutions to telecommunications problems within the area and with other areas.

2. English language standard. Unless agreed to otherwise, English shall be the language for all communications between and among SYSTEM OPERATORS and SYSTEM PERSONNEL responsible

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\(^1\) “Participating entity” refers to any system, operating, market or regional entity responsible for ensuring reliable and adequate system operations subject to NERC Operating Policy.

\(^2\) “Telecommunications facilities” refers to all voice and data, wire and wireless facilities used for the exchange of information.
for the real-time generation control and operation of the interconnected BULK ELECTRIC SYSTEM. Operations internal to the OPERATING AUTHORITY may use an alternate language.

C. Loss of Telecommunications

Requirements

1. Written instructions. Each Participating Entity shall have written operating instructions and procedures to enable continued operation of the system during loss of telecommunications facilities.

D. Security

Requirements

1. NERCnet security. Participating entities shall adhere to the requirements set forth in Appendix 7A, Attachment 2 – NERCnet Security Policy.
Policy 8 – Operating Personnel and Training

Policy Subsections

A. Responsibility and Authority
B. Training
C. Certification

This Policy defines the responsibilities, authorities and the certification standards, and the training requirements of SYSTEM OPERATORS.

A. Responsibility and Authority

Standard

Responsibilities and Authorities. The SYSTEM OPERATOR shall have the responsibility and authority to implement real-time actions that ensure the stable and reliable operation of the BULK ELECTRIC SYSTEM.
B. Training

[Appendix 8B1, Suggested Items for System Operator Training Courses.]

Requirements

1. **SYSTEM OPERATOR Training.** Each OPERATING AUTHORITY shall provide its SYSTEM OPERATORS with a coordinated training program that is designed to promote reliable operation. This program shall include:

   1.1. **Objectives.** Objectives based on NERC Operating Policies, Regional Council policies, OPERATING AUTHORITY operating procedures, and applicable regulatory requirements. These objectives shall reference the knowledge and competencies needed to apply those policies, procedures, and requirements to normal, emergency, and restoration conditions.

   1.2. **Training Plan.** A plan for the initial and continuing training that addresses required knowledge and competencies and their application in system operations.

   1.3. **Training time.** Dedicated training time for all SYSTEM OPERATORS to ensure their operating proficiency.

   1.4. **Training staff.** Individuals competent in both knowledge of system operations and instructional capabilities.

   1.5. **Verification of achievement.** Verification that all trainees have successfully demonstrated attainment of all required training objectives, including documented assessment of their training progress.

   1.6. **Evaluation.** Evaluations of training effectiveness to enhance further training.

   1.7. **Review.** Periodic review to ensure that training materials are technically accurate and complete and to ensure that the training program continues to meet its objectives.

Guides

1. **Practice situations.** Each OPERATING AUTHORITY should periodically practice simulated emergencies. The scenarios included in practice situations should represent a variety of operating conditions and emergencies.

2. **Unusual occurrences.** OPERATING AUTHORITIES should include disturbance reports and reports of other unusual occurrences in their training programs.
C. Certification

(Certification Specifications at: https://www.nerc.net/exam/)

Standards

1. Positions requiring NERC-Certified System Operators. An Operating Authority that maintains a control center(s) for the real-time operation of the interconnected Bulk Electric System, shall staff operating positions that meet both of the following criteria with NERC-Certified System Operators in accordance with the schedule in Standard 1:

   - Positions that have the primary responsibility, either directly or through communications with others, for the real-time operation of the interconnected Bulk Electric System, and
   - Positions that are directly responsible for complying with NERC Operating Policies.

2. Staffing Schedule. Operating positions identified in Standard 1 shall be staffed according to the following schedule:

   - After December 31, 1999, at least one NERC-Certified System Operator shall be on duty at all times, and
   - After December 31, 2000, all of these positions shall be staffed with NERC-Certified System Operators at all times.

   Exception – While in training to become a NERC-Certified System Operator, an uncertified individual may work only in a non-independent position and must be under the direct authority of a NERC-Certified System Operator.
Subsections

A. Next Day Operations Planning Process
B. Current Day Operations – Energy
C. Current Day Operations – Transmission

Introduction

This document contains the process and procedures that the NERC RELIABILITY COORDINATORS are expected to follow to ensure the operational reliability of the INTERCONNECTIONS. These include:

- Planning for next-day operations, including reliability analyses and identifying special operating procedures that might be needed,
- Analyzing current day operating conditions, and
- Implementing the INTERCONNECTION-wide transmission loading relief procedure or local procedures to mitigate overloads on the transmission system.

A. Next Day Operations Planning Process

When disseminating system analysis information, RELIABILITY COORDINATORS are expected to comply with the provisions of NERC’s “Confidentiality Agreement for Electric System Reliability.” [Appendix 4B]

Requirements

1. **Perform security analysis.** The RELIABILITY COORDINATORS shall ensure that next-day reliability analyses are performed simultaneously for all CONTROL AREAS and TRANSMISSION PROVIDERS in its RELIABILITY AREA to ensure that the bulk power system can be operated in anticipated normal and contingency conditions.

   1.1. **Information sharing.** Each CONTROL AREA in the RELIABILITY AREA shall provide information required for system studies, such as critical facility status, load, generation, operating reserve projections, and known INTERCHANGE TRANSACTIONS. This information shall be available by 1200 Central Standard Time for the Eastern INTERCONNECTION, and 1200 Pacific Standard Time for the Western INTERCONNECTION.

   1.2. **System Studies.** The RELIABILITY COORDINATORS shall conduct studies to identify potential interface and other OPERATING RELIABILITY LIMIT violations, including overloaded transmission lines and transformers, voltage and stability limits, etc.

2. **Study Results.** The RELIABILITY COORDINATORS shall share the results of their system studies, when conditions warrant, or upon request, with other RELIABILITY COORDINATORS, TRANSMISSION PROVIDERS, and CONTROL AREAS within their RELIABILITY AREA. Study results shall be available no later than 1500 Central Standard Time for the Eastern INTERCONNECTION, and 1500 Pacific Standard Time for the Western INTERCONNECTION, unless circumstances warrant otherwise. If the results of these studies indicate potential reliability problems, the
A. Next Day Operations Planning Process

RELIABILITY COORDINATORS shall issue the appropriate alerts via the Reliability Coordinator Information System (RCIS.)

3. Conference calls. Any time that conditions warrant, a conference call or other appropriate communications shall be initiated by any RELIABILITY COORDINATOR to address whatever problems are revealed by the reliability analyses.

4. Special operating procedures. Potential operating procedures that may be required shall be identified, including reconfiguration of the transmission system, redispachting of generation, or reduction or curtailment of INTERCHANGE TRANSACTIONS to maintain transmission loading within acceptable limits. [See Appendix C1, Subsection E, “Principles for Mitigating Constraints On and Off the Contract Path.”]
B. Current Day Operations – Energy


Requirements

1. **CONTROL AREA generation resource availability analysis.** Each NERC RELIABILITY COORDINATOR shall analyze generation resource availability and reserve levels for the CONTROL AREAS, RESERVE-SHARING GROUPS, and LOAD-SERVING ENTITIES in his RELIABILITY AREA to determine any actual or potential energy deficiencies.

2. **Authority to provide emergency assistance.** Each RELIABILITY COORDINATOR must have the authority to take or direct whatever action is needed to mitigate an energy emergency within his RELIABILITY AREA.

3. **Notification.** Each RELIABILITY COORDINATOR that is experiencing a potential or actual energy emergency within any CONTROL AREA, RESERVE-SHARING GROUP, or LOAD-SERVING ENTITY within his RELIABILITY AREA may initiate an ENERGY EMERGENCY ALERT as detailed in Appendix B, Subsection A – “Energy Emergency Alert Levels.”

4. **INTERCONNECTION FREQUENCY ERROR.** Any RELIABILITY COORDINATOR noticing an INTERCONNECTION FREQUENCY ERROR in excess of 0.03 Hz (Eastern INTERCONNECTION) or 0.05 Hz (Western and ERCOT INTERCONNECTIONS) for more than 20 minutes shall initiate a RELIABILITY COORDINATOR Hotline conference call, or notification via the RCIS, to determine the CONTROL AREA(S) with the energy emergency or control problem.
C. Current Day Operations – Transmission

[Policy 3A, “Interchange – Interchange Transaction Implementation”]
[Appendixes 9C1, 9C2, 9C3, “Transmission Loading Relief Procedures”]

Requirements

1. **Interchange Transaction information.** The RELIABILITY COORDINATOR shall ensure that information on all INTERCHANGE TRANSACTIONS is available to all RELIABILITY COORDINATORS in the INTERCONNECTION.

   1.1. **Interchange Distribution Calculator.** All INTERCHANGE TRANSACTIONS whose SOURCE CONTROL AREA or SINK CONTROL AREA, or both, are in the EASTERN INTERCONNECTION must be entered into the Interchange Distribution Calculator (IDC).

   [See also Appendix 3A2, “Tagging Across Control Area Boundaries.”]

   1.1.1. **Responsibility.** The RELIABILITY COORDINATOR for the SINK CONTROL AREA shall periodically audit the IDC to ensure that the INTERCHANGE TRANSACTION tags have been entered into the INTERCHANGE DISTRIBUTION CALCULATOR.

2. **Notify RELIABILITY COORDINATORS of potential problems.** The RELIABILITY COORDINATOR who foresees a transmission problem within his RELIABILITY AREA shall issue an alert to all CONTROL AREAS and Transmission Providers in his RELIABILITY AREA, and all RELIABILITY COORDINATORS within the INTERCONNECTION via the RCIS without delay.

3. **Implementing relief procedures.** If transmission loading progresses or is projected to progress beyond the OPERATING RELIABILITY LIMIT, the RELIABILITY COORDINATOR will perform the following procedures as necessary:

   3.1. **Manage INTERCHANGE TRANSACTIONS.** The RELIABILITY COORDINATORS will continue to manage INTERCHANGE TRANSACTIONS through their respective CONTROL AREAS during this period to help mitigate the OPERATING RELIABILITY LIMIT violation.

   3.2. **Selecting transmission loading relief procedure.** The RELIABILITY COORDINATOR experiencing a constraint on a transmission system within his RELIABILITY AREA shall, at his discretion, select from either a “local” (Regional, Interregional, or subregional) transmission loading relief procedure or an INTERCONNECTION-wide procedure, such as those listed in Appendix C1, C2, or C3.

   3.2.1. **Local transmission loading relief procedure.** The RELIABILITY COORDINATOR may use local transmission loading relief or congestion management procedures, provided the transmission system experiencing the constraint is a party to those procedures.
3.2.1.1. Use with an INTERCONNECTION-wide Procedure. A RELIABILITY COORDINATOR may implement a local transmission loading relief or congestion management procedure simultaneously with an INTERCONNECTION-wide procedure. However, he is obligated to follow the curtailments as directed by the INTERCONNECTION-wide procedure. If the RELIABILITY COORDINATOR desires to use a local procedure as a substitute for curtailments as directed by the INTERCONNECTION-wide procedure, he may do so only if such use is approved by the NERC Operating Reliability Subcommittee and Operating Committee.\(^1\)

3.2.1.2. IDC Update. The RELIABILITY COORDINATOR must enter, or have entered on his behalf, into the IDC all INTERCHANGE TRANSACTION changes that result from the implementation of the local procedure.

\[Eastern Interconnection Requirement\]

3.2.2. INTERCONNECTION-wide loading relief procedure. The RELIABILITY COORDINATOR may implement an INTERCONNECTION-wide procedure as detailed in Appendixes 9C1, 9C2, or 9C3.

3.2.2.1. Obligations. When implemented, all RELIABILITY COORDINATORS shall comply with the provisions of the INTERCONNECTION-wide procedure. This may include action by RELIABILITY COORDINATORS in other INTERCONNECTIONS to, for example, curtail an INTERCHANGE TRANSACTION that crosses an INTERCONNECTION boundary.

3.3. Compliance with Interchange Policies. During the implementation of relief procedures, and up to the point that emergency action is necessary, RELIABILITY COORDINATORS and CONTROL AREAS shall comply with the Requirements of Policy 3, “Interchange.”

4. Implementing emergency procedures. If the transmission loading condition is deemed critical to bulk system reliability by a RELIABILITY COORDINATOR, the RELIABILITY COORDINATOR has the authority to immediately direct the CONTROL AREAS in his RELIABILITY AREA to redispach generation, reconfigure transmission, or reduce load to mitigate the critical condition until INTERCHANGE TRANSACTIONS can be reduced utilizing a transmission loading relief procedure, or other procedures, to return the system to a reliable state. The RELIABILITY COORDINATOR shall coordinate these emergency procedures with other RELIABILITY COORDINATORS as appropriate. All CONTROL AREAS shall comply with all requests from their RELIABILITY COORDINATOR as authorized by the Regional Reliability Plan.

5. Reestablishing INTERCHANGE TRANSACTIONS. The RELIABILITY COORDINATOR shall coordinate with the CONTROL AREAS in his RELIABILITY AREA, and with other RELIABILITY COORDINATORS as appropriate, the reestablishment of the INTERCHANGE TRANSACTIONS that were curtailed. The reestablishment of these INTERCHANGE TRANSACTIONS and the resulting INTERCHANGE SCHEDULES shall be in compliance with Policy 3, “Interchange.”

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\(^1\) Examples would be 1) a local procedure that curtails INTERCHANGE TRANSACTIONS in a different order or ratio than the INTERCONNECTION-wide procedure, or 2) a local redispach procedure.
APPENDIXES
Appendix 1A – The Area Control Error (ACE) Equation

Appendix Subsections
A. The ACE Equation
B. Jointly Owned Units
   1. Pseudo-Tie
   2. Dynamic Schedule
C. Supplemental Regulation Service
D. Load or Generation Transfer by Telemetry
E. Summary

A. The ACE Equation

It is the obligation of each CONTROL AREA to fulfill its commitment to the Interconnection and not burden the other CONTROL AREAS in the INTERCONNECTION. Each CONTROL AREA should minimize their effect on other CONTROL AREAS within the INTERCONNECTION. Any errors incurred because of generation, load or schedule variations or because of jointly owned units, contracts for regulation service, or the use of dynamic schedules must be kept between the involved parties and not passed to the INTERCONNECTION. In addition, this ACE should NOT include any offsets (e.g., unilateral inadvertent payback, Western INTERCONNECTION automatic time error control, etc.)

The equation for ACE is:

\[
ACE = (NIA - NIS) - 10\beta (FA - FS) - IME
\]

In this equation, \( NIA \) accounts for all actual meter points that define the boundary of the CONTROL AREA and is the algebraic sum of flows on all tie lines. Likewise, \( NIS \) accounts for all scheduled tie flows of the CONTROL AREA. The combination of the two \( (NIA - NIS) \) represents the ACE associated with meeting schedules and if used by itself for control would be referred to as flat tie line regulation.

The second part of the equation, \( 10\beta (FA - FS) \), is a function of frequency. The \( 10\beta \) represents a CONTROL AREA’s frequency bias (\( \beta \)’s sign is negative) where \( \beta \) is the actual frequency bias setting (MW/0.1 Hz) used by the CONTROL AREA and 10 converts the frequency setting to MW/Hz. \( FA \) is the actual frequency and \( FS \) is the scheduled frequency. \( FS \) is normally 60 Hz but may be offset to effect manual time error corrections.

\( IME \) is the meter error recognized as being the difference between the integrated hourly average of the net tie line instantaneous interchange MW \( (NIA) \) and the hourly net interchange demand measurement \( (MWh) \). This term should normally be very small or zero.
B. Jointly Owned Units

Jointly owned units (JOU) must be accounted for properly by all owners. The following examples illustrate the methodology. CONTROL AREA X and CONTROL AREA Y each has a unit in their CONTROL AREA jointly owned by both CONTROL AREAS. Unit 1 is in CONTROL AREA X and unit 2 is in CONTROL AREA Y. The ACE equation for CONTROL AREA X must reflect its ownership of both units. Two components are required: one to reflect X’s ownership in unit 2 and one to reflect Y’s ownership of unit 1. CONTROL AREA Y’s ACE equation will likewise have two components, one for its ownership in unit 1 and one for X’s ownership of unit 2. If fixed schedules aren’t used, JOUs may be handled as a pseudo-tie or a dynamic schedule.

1. Pseudo-Tie

If the Jointly owned units are considered pseudo-ties then the NI\textsubscript{S} remains prearranged schedules and the NI\textsubscript{A} term becomes NI\textsubscript{a} − IA\textsubscript{JOUE} − IA\textsubscript{JOUI} where:

NI\textsubscript{a} = actual tie flows.

IA\textsubscript{JOUE} = pseudo-tie for JOU external to a CONTROL AREA.

IA\textsubscript{JOUE} is assumed negative for external generation coming into the CONTROL AREA as a pseudo-tie.

IA\textsubscript{JOUI} = pseudo-tie for JOU internal to a CONTROL AREA.

Incoming power is negative.
Outgoing power is positive.

For example:

Assume Unit 1 in CONTROL AREA X is generating 400 MW.
100 MW owned by X
300 MW owned by Y

Assume Unit 2 in CONTROL AREA Y is generating 300 MW.
50 MW owned by X
250 MW owned by Y

Representing the units as a pseudo-tie the equations become:
For CONTROL AREA X: NI\textsubscript{a} = NI\textsubscript{a} − (−50) − 300
For CONTROL AREA Y: NI\textsubscript{a} = NI\textsubscript{a} − (−300) − 50

Note: IA\textsubscript{JOUE} is assumed negative for external generation coming into the CONTROL AREA as a pseudo-tie.
Appendix 1A – The Area Control Error (ACE) Equation

2. **Dynamic Schedule**

If reflected as a dynamic schedule, the NIₐ remains actual tie flows and the NIₛ becomes NIₐ + ISJOUE + ISJOUI.

NIₐ = prearranged schedules.

ISJOUE = dynamic schedule for JOU external to a CONTROL AREA.
ISJOUE is assumed negative for external generation coming into the CONTROL AREA as a dynamic schedule.

ISJOUI = dynamic schedule for JOU internal to a CONTROL AREA.

Incoming power is negative.
Outgoing power is positive.

For example:

Assume Unit 1 in CONTROL AREA X is generating 400 MW
100 MW owned by X
300 MW owned by Y

Assume Unit in CONTROL AREA Y is generating 300 MW
50 MW owned by X
250 MW owned by Y

Representing the unit as a dynamic schedule the equations become:
For CONTROL AREA X: NIₛ = NIₐ − 50 + 300
For CONTROL AREA Y: NIₛ = NIₐ − 300 + 50

Note: ISJOUE is assumed negative for external generation coming into the CONTROL AREA as a dynamic schedule.

C. **Supplemental Regulation Service**

Supplemental regulation service is required when one CONTROL AREA takes over all or part of the regulation requirements of another CONTROL AREA without incorporating its ties and schedules. In this case, both CONTROL AREAS should handle this in a consistent manner as a dynamic schedule. Adding another component, ISC to both CONTROL AREAS’ ACE with the proper sign convention will ensure proper control. Example: Assume CONTROL AREA X is purchasing regulation service from CONTROL AREA Y. For area X, ISC would be subtracted from CONTROL AREA X’s ACE for overgeneration and added for undergeneration. Likewise, area Y’s ISC would be added to CONTROL AREA Y’s ACE for X’s overgeneration and subtracted for X’s undergeneration.
D. Load or Generation Transfer By Telemetry

Dynamic scheduling may also be used for telemetered transfer of load or generation from one CONTROL AREA to another. Again both areas must modify their ACE equation. To transfer load, the CONTROL AREA giving up the load adds it to its ACE equation (+ISL). The CONTROL AREA accepting the load subtracts it from its ACE equation (−ISL). Likewise for generation, the CONTROL AREA giving up generation subtracts it (−ISG) and the CONTROL AREA accepting the generation adds it (+ISG).

E. Summary

The ACE equation is:

\[ \text{ACE} = (\text{NIA} - \text{NIS}) - 10\beta (F_A - F_S) - I_{ME} \]

For the ERCOT INTERCONNECTION:

\[ \text{ACE} = (\text{NIA} - \text{NIS}) + 10\beta (F_A - F_S) \]

Note: ERCOT defines \( \beta \) as a positive number

After considering regulation service and electronic load or generation transfer:

\[ \text{NIA} = \text{NIA} \]
\[ \text{NIS} = \text{NIS} \pm ISC \pm ISG \pm ISL \]

If jointly owned units are treated as pseudo-ties:

\[ \text{NIA} = \text{NIA} - I_{JOUSE} - I_{JOUU} \]
\[ \text{NIS} = \text{NIS} \pm ISC \pm ISG \pm ISL \]

If jointly owned units are treated as dynamic schedules:

\[ \text{NIA} = \text{NIA} \]
\[ \text{NIS} = \text{NIS} - I_{SJOUE} + I_{SJOUI} \pm ISC \pm ISG \pm ISL \]

To work properly, all transferred load or generation and all ties must be metered. All values of the ACE equation should be processed at the same time rate. A proper sign convention for load and generation must be agreed upon and adhered to by all involved CONTROL AREAS.
Appendix 1D – Time Error Correction Procedures

Version 2

<table>
<thead>
<tr>
<th>Time</th>
<th>Initiation</th>
<th>Termination</th>
<th>Scheduled</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>East</td>
<td>West</td>
<td>ERCOT</td>
</tr>
<tr>
<td>Slow</td>
<td>–10</td>
<td>–2</td>
<td>–3</td>
</tr>
<tr>
<td>Fast</td>
<td>+10</td>
<td>+2</td>
<td>+3</td>
</tr>
</tbody>
</table>

Notes:

For the Eastern Interconnection:

1. No corrections for fast time will be initiated between 0400–1100 Central Time.
2. Corrections begin on the hour or half-hour.
3. Corrections shall last at least one hour, unless there is a cause for termination.

For all Interconnections:

1. A time correction may be halted, terminated, or extended if the designated Interconnection Time Monitor determines system conditions warrant such action.
2. After the premature termination of a manual time correction, a slow time correction can be reinstated after the frequency has returned to 60 Hz or above for a period of ten minutes. A fast time correction can be reinitiated after the frequency has returned to 60 Hz or lower for a period of ten minutes. At least one hour shall elapse, however, between the termination and re-initiation notices.
Appendix 1F – Inadvertent Interchange Dispute Resolution Process, Error Adjustment Procedures, and On- and Off-Peak Periods

Appendix Subsections
A. Dispute Resolution
B. Error Adjustment Procedure
C. On-Peak and Off-Peak Periods

Introduction
Adjacent CONTROL AREAS that cannot mutually agree upon their respective Net Interchange quantities by the tenth calendar day of the following month shall submit a report to their respective Resources Subcommittee representative. The report shall describe the nature and the cause of the dispute as well as a process for correcting the discrepancy. Should the submitted processes not work, the process for resolving the dispute is described herein.

A. Dispute Resolution

1. Regional Subcommittee Representative reporting requirements. The Resources Subcommittee representative shall accept the CONTROL AREA’S report describing the disputed values. To comply with the reporting requirements of Policy 1F Standard 5.2.2. that representative shall contact the Resources Subcommittee representative for the opposing CONTROL AREA (if the dispute is between CONTROL AREAS in different Regions). The representative(s) shall determine a set of values, which will be reported to NERC. The report(s) will identify:

   1.1. The names of the disputing CONTROL AREAS.

   1.2. The reported monthly Net Interchange Schedule (On-Peak and Off-Peak) between the disputing CONTROL AREAS.

   1.3. The mutually agreed to monthly Net Interchange Schedule (On-Peak and Off-Peak) between the disputing CONTROL AREAS (used to compute the Regional Inadvertent Interchange).

   1.4. The reported monthly NET ACTUAL INTERCHANGE (On-Peak and Off-Peak) between the disputing CONTROL AREAS.

   1.5. The mutually agreed to monthly Net Actual Interchange (On-Peak and Off-Peak) between the disputing CONTROL AREAS (used to compute the Regional Inadvertent Interchange).

2. NERC Staff reporting requirements. The NERC staff representative to the Resources Subcommittee shall receive the Regional reports and, using the mutually agreed to data, compile a balanced INADVERTENT INTERCHANGE SUMMARY report. This report will also include a tabulated list of the CONTROL AREAS that have disputed data, as well as the magnitude of the data.
in dispute. This report will be distributed to the Operating Committee as well as the Resources Subcommittee by the 1st of the succeeding month.

3. Dispute Resolution. All disputes between CONTROL AREAS within a Region shall be referred to the regional process for dispute resolution to resolve the dispute on an informal basis within 30 days of the issuance of the NERC INADVERTENT INTERCHANGE SUMMARY report.

3.1. All disputes between CONTROL AREAS in different Regions shall be referred to the respective Regions’ Operating Committee representatives, or other Regional-approved representatives, for resolution on an informal basis within 30 days of the issuance of the NERC INADVERTENT INTERCHANGE SUMMARY report.

3.2. In the event that the informal procedures do not resolve the dispute within 30 days, the dispute shall be submitted to binding arbitration as described below.

4. Binding Arbitration. A professional arbitration service will provide each of the parties in the dispute an opportunity to be heard. Within 30 days of those presentations, the arbitrator shall issue a decision. The decision and the rationale for the decision shall be provided in writing to the disputing parties.

B. Error Adjustment Procedure

Periodic Adjustments shall be made to correct for differences between hourly MWh meter totals and the totals derived from register readings of the tie-line meters. Adjacent CONTROL AREAS shall agree upon the difference determined above and assign this correction to the proper On-Peak and Off-Peak period at the same times and in equal quantities in the opposite directions. Any adjustments necessary due to known metering errors, franchised territories, transmission losses or other special circumstances shall be made in the same manner.

Adjustments to schedules shall only be made if an incorrect schedule was used by one CONTROL AREA. Schedules shall not be adjusted after-the-fact due to marketing considerations or adjustments during the billing procedure.
C. On-Peak and Off-Peak Periods

1. On-Peak and Off-Peak Hours (Monday Through Sunday)

On- and Off-Peak designation. The hourly inadvertent energy created by a CONTROL AREA is classified as either On-Peak or Off-Peak inadvertent. The peak designation assigned is a function of hour of day, day of week, time zone, prevailing time (standard or daylight savings), and special holiday status.

Daylight saving time. The On-Peak to Off-Peak and Off-Peak to On-Peak boundary hours are unaffected by transitions to or from daylight savings time. If a CONTROL AREA remains on either standard or daylight savings time throughout the year, their inadvertent accounting practices shall use prevailing time.

On-peak hours. Each INTERCONNECTION has a reference time zone and standardized On-Peak and Off-Peak periods. On-Peak periods are summarized in the table below for each INTERCONNECTION. Sundays and special holidays are designated to be Off-Peak periods for the entire day. Hours for Monday through Saturday that are not shown in the table below are also designated as Off-Peak hours.

2. On-Peak Hours For Monday Through Saturday In Hour-Ending Format

<table>
<thead>
<tr>
<th>Interconnection</th>
<th>Reference Time Zone</th>
<th>Hour Ending</th>
</tr>
</thead>
<tbody>
<tr>
<td>Eastern</td>
<td>Central</td>
<td>0700-2200</td>
</tr>
<tr>
<td>ERCOT</td>
<td>Central</td>
<td>0800-2200</td>
</tr>
<tr>
<td>Western</td>
<td>Pacific</td>
<td>0700-2200</td>
</tr>
</tbody>
</table>

3. Additional Off-Peak Holidays for the Eastern and Western Interconnections

There are six identified U.S. holidays each year:

- New Year’s Day
- Memorial Day
- Independence Day
- Labor Day
- Thanksgiving Day
- Christmas Day

If any of these holidays fall on a Sunday, the following Monday will be considered an Off-Peak day. Otherwise, the Off-Peak day will be the holiday itself.
Appendix 1H – Minimum Data Collection Requirements for Use in Monitoring NERC Performance Standards

Appendix Subsections
A. Required Data Records
B. Recording Chart Speed and Width
C. Digital Collection
D. Range for ACE Chart Recorder
E. Range for Frequency Chart Recorder
F. Range for Net Tie Deviation from Schedule Recorder
G. Range for Net Interchange Recorder
H. Measure Accuracy
I. Data Retention

The minimum requirements for control center records (either chart recorders or digital data) used for monitoring NERC Control Performance Criteria are provided here as a guide for control areas to establish uniform data recording and monitoring throughout each Interconnection.

A. Required Data Records

The following data must be digitally recorded for NERC Performance Standard assessment. The use of a visible chart recorder or other device is optional.

- Area Control Error (ACE)
- System frequency
- Net tie deviation from schedule
- Net interchange
- Frequency bias (for those systems with variable bias)

B. Recording Chart Speed and Width

In order to provide usable data for performance monitoring, the following chart width and speed is recommended:

- Chart width: nominal 10" full-scale
- Chart speed: 3" per hour

C. Digital Collection

As a general rule, digital data should be sampled at least at the same periodicity with which ACE is calculated. Missing or bad data should be flagged. Collected data should be co-incident; i.e., ACE, system frequency, net interchange, and other data should all be saved at the same time. The format for digital storage should be a standard such as ASCII or EBCDIC for compatibility and portability to other entities.
D. Range for ACE Chart Recorder

The range for the ACE recorder should provide the best resolution for normal operating conditions. Typically, the recorder should use between 1/3 and 2/3 of the chart width during normal operation.

E. Range for Frequency Chart Recorder

The following ranges shall cover full scale on the recorder:

<table>
<thead>
<tr>
<th>Interconnection</th>
<th>Band</th>
<th>Range</th>
</tr>
</thead>
<tbody>
<tr>
<td>Eastern</td>
<td>Narrow</td>
<td>60 ± 0.25 Hz</td>
</tr>
<tr>
<td></td>
<td>Wide</td>
<td>60 ± 3.00 Hz</td>
</tr>
<tr>
<td>Western</td>
<td>Narrow</td>
<td>60 ± 0.30 Hz</td>
</tr>
<tr>
<td></td>
<td>Wide</td>
<td>60 ± 5.00 Hz</td>
</tr>
<tr>
<td>ERCOT</td>
<td>Narrow</td>
<td>60 ± 0.50 Hz</td>
</tr>
<tr>
<td></td>
<td>Wide</td>
<td>60 ± 5.00 Hz</td>
</tr>
</tbody>
</table>

Frequency input to the chart recorder shall be an analog signal obtained from a source independent from the control system computer.

F. Range for Net Tie Deviation from Schedule Recorder

Net tie deviation from schedule is the actual net interchange minus scheduled net interchange. The purpose of monitoring net tie deviation from schedule is to provide a measurable interchange response in MW for frequency excursions. This will enable the control areas to more accurately calculate the frequency bias values and comply with NERC frequency response surveys.

The recommended range for this data quantity is ±2 times the control area frequency bias. Even extreme frequency excursions are less than ±0.1 Hz, therefore, ±2 times the control area frequency bias should provide sufficient range and good resolution for external disturbances.
Appendix 1H – Minimum Data Collection Requirements for Use in Monitoring NERC Performance Standards

G. **Range for Net Interchange Recorder**

The range for the net interchange recorder should provide the best resolution for all operating conditions. Some of the possible net interchange conditions, which can occur are:

- Operation at the maximum import/export limit
- Import due to loss of the largest generating unit
- Normal import/export net interchange

In order to get the best resolution for the various interchange conditions, the recorder range should be variable. For example, if normal import/export is ±100 MW and maximum import/export is ±500 MW, then a recorder range that is variable in ±100 MW increments is recommended.

H. **Measure Accuracy**

Control performance and reliable operation is affected by the accuracy of the measuring devices. The recommended minimum values are listed below:

<table>
<thead>
<tr>
<th>Device</th>
<th>Accuracy</th>
<th>Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>Digital frequency transducer</td>
<td>± 0.001</td>
<td>Hz</td>
</tr>
<tr>
<td>MW, MVAR, and voltage transducer</td>
<td>± 0.25</td>
<td></td>
</tr>
<tr>
<td>Remote terminal unit</td>
<td>± 0.25</td>
<td>% of full scale</td>
</tr>
<tr>
<td>Potential transformer</td>
<td>± 0.30</td>
<td></td>
</tr>
<tr>
<td>Current transformer</td>
<td>± 0.50</td>
<td></td>
</tr>
</tbody>
</table>

I. **Data Retention**

1. **Performance Standard Data.** Each control area shall retain its ACE, frequency, net tie deviation, and net interchange data for at least one year.

   1.1 Digital information should be kept for at least one year based on the same scan rate at which data is collected. The control area should have the equivalent digital data that would be necessary to create its analog chart.

2. **Disturbance Control Performance Data.** Each control area or Reserve Sharing Group shall retain documentation of the magnitude of each reportable disturbance as well as the ACE charts and/or samples used to calculate the control area’s or Reserve Sharing group’s disturbance Recovery values (Ri’s). The data shall be retained for one year following the reporting quarter the data was used for.
Appendix 3A1 – Tag Submission and Response Timetables

Version 3

[“E-Tag Reference Document”]
[“Transaction Tagging Process within ERCOT Reference Document”]

Appendix Subsections

A. Eastern Interconnection – New Transactions
B. Western Interconnection – New Transactions
C. Interchange Transaction Corrections
D. Interchange Transaction Modifications

A. Eastern Interconnection – New Transactions

The table below represents the recommended business practices for tag submission and assessment deadlines within the Eastern Interconnection. These are default requirements; some regulatory or provincially approved provider practices may have requirements that are more stringent. Under these instances, the more restrictive criteria shall be adhered to. The table describes the various minimum submission and assessment timing requirements.

Table 1: Eastern Interconnection – Timing Requirements

<table>
<thead>
<tr>
<th>Transaction Duration</th>
<th>PSE Submit Deadline*</th>
<th>Actual Tag Submission Time</th>
<th>Provider Assessment Time</th>
<th>Time to Start of Transaction</th>
</tr>
</thead>
<tbody>
<tr>
<td>Less than 24 Hours</td>
<td>20 Minutes prior to start</td>
<td>≤1 Hour prior to start</td>
<td>≤10 Minutes from tag receipt</td>
<td>≥10 Min</td>
</tr>
<tr>
<td></td>
<td></td>
<td>&gt;1 to &lt;4 hours prior to start</td>
<td>≤20 Minutes from tag receipt</td>
<td>≥40 Min</td>
</tr>
<tr>
<td></td>
<td></td>
<td>≥4 Hours prior to start</td>
<td>≤2 Hours from tag receipt</td>
<td>≥2 Hours</td>
</tr>
<tr>
<td>24 Hours or longer</td>
<td>4 Hours prior to start</td>
<td>Any</td>
<td>≤2 Hours from tag receipt</td>
<td>≥2 Hours</td>
</tr>
</tbody>
</table>

*Start time references are for start of the TRANSACTION not the start of the ramp.

Tag submission timing requirements are based on the duration of the TRANSACTION. Tags representing TRANSACTIONS that run for less than one day (24 hours) must be submitted at least 20 minutes prior to the start of the TRANSACTION (excluding ramp time). Tags representing TRANSACTIONS running for one day or more (24 hours or more) must be submitted at least four hours prior to the start. Tags submitted that meet these requirements shall be considered “on-time” by the E-Tag system and may be granted conditional approval. Tags submitted that do not meet these requirements shall be considered “late” by the E-Tag system, and consequently will be denied if not explicitly approved by all parties.
Appendix 3A1 – Tag Submission and Response Timetable

A. Eastern Interconnection – New Transactions

The E-Tag system accepts tags with a start time up to one hour prior to the current time. Tags with a start time older than one hour will be rejected as invalid. This one-hour window shall be used to submit tags to document emergency actions taken to mitigate an OPERATING SECURITY LIMIT violation (Policy 3, Section A 2.4.1). This provision shall not be used to schedule TRANSACTIONS without the proper tag (Policy 3, Section A 6.1).

Tag assessment timing requirements are based on the submission time of the tag, as well as the duration. Hourly tags submitted one hour or less prior to start must be evaluated in ten minutes. Hourly tags submitted more than one hour but less than four hours prior to start must be evaluated in 20 minutes. Tags with a duration of less than 24 hours that are submitted four hours or more prior to start must be evaluated in two hours. Tags with a duration of 24 hours or more must be evaluated in two hours.

**Timing Requirements for Reallocation when in a TLR Event**

During a NERC TLR event, TRANSACTIONS may be submitted to replace existing TRANSACTIONS with a lower transmission priority. The new TRANSACTION tag must be received by the Interchange Distribution Calculator no later than 35 minutes prior to the top of the hour to allow time for RELIABILITY COORDINATOR to assess the impact of reallocation.
**B. Western Interconnection – New Transactions**

The tables below represent the recommended business practices for tag submission and assessment deadlines within the Western Interconnection. These are default requirements. The tables describe the various minimum submission and assessment timing requirements.

**Table 2: Western Interconnection – Timing Requirements**

<table>
<thead>
<tr>
<th>Transaction Start/Submittal Time</th>
<th>Late Status Deadline</th>
<th>Actual Tag Submission Time*</th>
<th>Provider Assessment Time</th>
<th>Approval/Denial Notes</th>
<th>Time to Start of Transaction*</th>
</tr>
</thead>
<tbody>
<tr>
<td>Start 00:00 next day or beyond when submitted prior to 18:00 of the current day</td>
<td>15:00 day prior to start</td>
<td>Any</td>
<td>3 hours</td>
<td>Passive Approval if submitted before deadline, else Passive Denial. Deferred denial</td>
<td>≥ 6 Hours</td>
</tr>
<tr>
<td>Start 00:00 next day and submitted between 18:00 and 23:59:59 on day prior to start – OR – start within current day</td>
<td>≥ 4 Hours prior to start</td>
<td>2 Hours from tag receipt</td>
<td>Passive Approval Deferred denial</td>
<td>≥ 2 Hours</td>
<td></td>
</tr>
<tr>
<td></td>
<td>&lt;4 Hours to ≥1 Hour prior to start</td>
<td>20 minutes from tag receipt</td>
<td>Passive Approval Deferred denial</td>
<td>≥ 40 Min</td>
<td></td>
</tr>
<tr>
<td></td>
<td>&lt;1 hour to ≥30 minutes prior to start</td>
<td>10 minutes from tag receipt</td>
<td>Passive Approval Deferred denial</td>
<td>≥ 20 Min</td>
<td></td>
</tr>
<tr>
<td></td>
<td>&lt;30 minutes to ≥20 minutes prior to start</td>
<td>10 minutes from tag receipt</td>
<td>Passive Approval Deferred denial</td>
<td>≥ 10 Min</td>
<td></td>
</tr>
<tr>
<td></td>
<td>20 minutes prior to start</td>
<td>&lt;20 minutes prior to start</td>
<td>5 minutes from tag receipt</td>
<td>Passive Denial. Deferred denial</td>
<td>Submission time minus maximum time of 5 minutes</td>
</tr>
</tbody>
</table>
Appendix 3A1 – Tag Submission and Response Timetable

B. Western Interconnection – New Transactions

Notes/Clarification:

1. All clock times are in PPT.
2. Tags falling under the criteria in yellow are deemed pre-schedule tags.
3. Tags falling under the criteria in green are deemed real-time tags.
4. Pre-schedule tags submitted between 15:00 and 18:00 will be assigned LATE composite status.
5. Real-time tags submitted after 20 minutes prior to the start of the Transaction will be assigned LATE composite status.

*Start-time references are for start of the Transaction, not the start of the ramp.

Tag submission timing requirements are based on the type and duration of the TRANSACTION. Tags representing TRANSACTIONS that run for less that one day (24 hours) within the current day must be submitted at least 20 minutes prior to the start of the TRANSACTION (excluding ramp time). Tags representing TRANSACTIONS that are pre-scheduled to start the next day must be submitted by 1500 PST the day prior to the day the TRANSACTION is to start. Tags submitted that meet these requirements shall be considered “on-time” by the E-Tag system and may be granted conditional approval. Tags submitted that do not meet these requirements shall be considered “late” by the E-Tag system, and consequently will be denied if not explicitly approved by all parties.

The E-Tag system accepts tags with a start time up to one hour prior to the current time. Tags with a start time older than one hour will be rejected as invalid. This one-hour window shall be used to submit tags to document emergency actions taken to mitigate an OPERATING SECURITY LIMIT violation (Policy 3, Section A 2.4.1). This provision shall not be used to schedule TRANSACTIONS without the proper tag (Policy 3, Section A 6.1).

Tag assessment timing requirements are based on the submission time of the tag as well as the duration. Hourly tags submitted one hour or less prior to start must be evaluated in ten minutes. Hourly tags submitted more than one hour but less than four hours prior to start must be evaluated in 20 minutes. Tags with a duration of less than 24 hours that are submitted four hours or more prior to start must be evaluated in two hours. Tags submitted for pre-scheduled service starting the next day or a future day must be evaluated in three hours.
C. Interchange Transaction Corrections

TRANSACTION Corrections (as described in “Appendix 3A4, “Required and Correctable Tag Data””) may be provided by Tag Authors to replace non-reliability data listed in a tag. As each correction is received, the Evaluation Time of the TRANSACTION will extend, based on the following rules:

- Each correction shall extend the evaluation time by ten minutes
- At no time can the evaluation time be extended past the start time of the TRANSACTION.
- Each correction shall reset the approval status of those entities affected by the correction
- The segment or segments corrected will be eligible for passive approval if the correction is received within the timelines specified below, except in the case where the TRANSACTION has already been set for passive denial. The segment or segments corrected will be subject to passive denial if the correction is not received within the timelines specified below. At no point may a TRANSACTION segment already under Passive Denial constraints be returned to Passive Approval eligibility.

Table 3: Correction Submission Requirements*

<table>
<thead>
<tr>
<th>Eastern Interconnection</th>
<th>Western Interconnection</th>
</tr>
</thead>
<tbody>
<tr>
<td>20 minutes prior to start</td>
<td>30 minutes prior to start</td>
</tr>
</tbody>
</table>

*Start time references are for start of the Transaction not the start of the ramp.
D. Interchange Transaction Modifications

Curtailments, reloads, market-initiated modifications, and other TRANSACTION modifications that affect energy profiles must be received by and evaluated within certain times. The following tables describe the submission and evaluation requirements for such changes.

Modification requests received by the deadlines specified below shall be considered “on time,” and are eligible for Passive Approval. Modification requests received past the deadlines shall be considered “late,” and are considered denied unless explicitly approved by all parties.

### Table 4: Eastern Interconnection – Modifications

<table>
<thead>
<tr>
<th>Modification Type</th>
<th>Requestor Submission Deadline***</th>
<th>Actual Submission Time***</th>
<th>Evaluation Time</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reliability (Curtailments or Reloads)</td>
<td>20 minutes prior to modification start**</td>
<td>Less than 30 minutes to start</td>
<td>10 minutes</td>
</tr>
<tr>
<td></td>
<td></td>
<td>30 minutes or more prior to start</td>
<td>15 minutes</td>
</tr>
<tr>
<td>Market – Committed Transmission Reservation(s)</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>Reductions</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>20 minutes prior to modification start**</td>
<td>Less than 30 minutes to start</td>
<td>10 minutes</td>
</tr>
<tr>
<td></td>
<td></td>
<td>30 minutes or more prior to start</td>
<td>15 minutes</td>
</tr>
</tbody>
</table>

***Start time references are for start of the Transaction not the start of the ramp.

### Table 5: Western Interconnection – Modifications

<table>
<thead>
<tr>
<th>Modification Type</th>
<th>Requestor Submission Deadline***</th>
<th>Actual Submission Time***</th>
<th>Evaluation Time</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reliability (Curtailments or Reloads)</td>
<td>25 minutes prior to modification start**</td>
<td>Less than 30 minutes to start</td>
<td>10 minutes</td>
</tr>
<tr>
<td></td>
<td></td>
<td>30 minutes or more prior to start</td>
<td>15 minutes</td>
</tr>
<tr>
<td>Market – Committed Transmission Reservation(s)</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>Reductions</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>25 minutes prior to modification start**</td>
<td>Less than 30 minutes to start</td>
<td>10 minutes</td>
</tr>
<tr>
<td></td>
<td></td>
<td>30 minutes or more prior to start</td>
<td>15 minutes</td>
</tr>
</tbody>
</table>

***Start time references are for start of the Transaction not the start of the ramp.

*See Special Exception for Cancellations below
**Special Exception for Cancellations**

A cancellation is defined as setting both committed transmission reservation(s) and energy flow to zero for the duration of the TRANSACTION prior to the start of a TRANSACTION but following that TRANSACTIONS approval. In the event that a Tag Author elects to cancel a TRANSACTION, the following timelines should be utilized:

**Table 6: Special Exception for Cancellations Submission and Evaluation Timing**

<table>
<thead>
<tr>
<th>Region</th>
<th>Submission Deadline*</th>
<th>Evaluation Time</th>
</tr>
</thead>
<tbody>
<tr>
<td>Eastern Interconnection</td>
<td>15 minutes prior to transaction start</td>
<td>If received by deadline, no evaluation required. Request is automatically approved.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>If not received by deadline, request is not eligible for Special Exception for Cancellations, and must be processed normally.</td>
</tr>
<tr>
<td>Western Interconnection</td>
<td>20 minutes prior to transaction start</td>
<td>If received by deadline, no evaluation required. Request is automatically approved.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>If not by deadline, request is not eligible for Special Exception for Cancellations, and must be processed normally.</td>
</tr>
</tbody>
</table>

*Start time references are for start of the Transaction not the start of the ramp.
Appendix 3A2 – Tagging Across Interconnection Boundaries
Version 2 for Interim Implementation

A. Between ERCOT and Eastern Interconnections

A PURCHASING-SELLING ENTITY that is seeking transmission arrangements to schedule energy between the ERCOT and Eastern Interconnections will coordinate through the SPP RELIABILITY COORDINATOR. Requests for service must be made to the SPP RELIABILITY COORDINATOR for service into or through SPP (including service across either the North or East DC Ties) via the SPP OASIS. Request for service must also be made in ERCOT via the ERCOT OASIS. The SPP RELIABILITY COORDINATOR will coordinate approval of reservations and schedules involving the SPP portion of transmission service (including the DC ties) and service in ERCOT.

The following procedures are followed when scheduling transmission service between SPP and ERCOT:

- The PURCHASING-SELLING ENTITY must receive approval for DC tie service and transmission service in SPP from the SPP RELIABILITY COORDINATOR for the proposed transaction and arrange required ancillary services.
- For all transmission service requests, the PURCHASING-SELLING ENTITY will create a NERC Tag and submit it to the SPP RELIABILITY COORDINATOR. The SPP RELIABILITY COORDINATOR will validate certain information on the tag and check that a reservation exists before approving the tag. The approved tag will be available to the parties to the transaction and the ERCOT ISO.
- Simultaneous with submitting requests using the NERC TAG to the SPP RELIABILITY COORDINATOR (for next hour, non-firm and all other transmission service requests), the PURCHASING-SELLING ENTITY submits requests to the ERCOT ISO via the ERCOT OASIS. The MW profile information submitted to ERCOT must exactly match the information on the NERC Tag supplied to ERCOT by the SPP RELIABILITY COORDINATOR. (See note.)
- The SPP RELIABILITY COORDINATOR coordinates approval of the transaction if ATC is available in SPP and across the DC tie, and works with the ERCOT ISO to coordinate ATC calculations in ERCOT.
- The ERCOT ISO notifies the delivering/receiving ERCOT CONTROL AREA of the approved transaction and provides a copy of the NERC Tag and ERCOT schedule request.
- The delivering/receiving ERCOT CONTROL AREA communicates with the delivering/receiving control area outside of ERCOT, confirms the transaction/schedule, and confirms with the DC tie operator.
- The DC tie operator will follow the NERC Tag when setting flows across the tie.

- Note: In ERCOT, there are two types of wholesale transmission services—planned and unplanned. Planned Transmission Service is service for nominated generating resources to specified loads. All other transmission service is unplanned.
The SPP RELIABILITY COORDINATOR will use the NERC Tag to populate the iIDC and to determine constrained facility ATC in the operating horizon.

ERCOT ISO requires transactions/schedules involving use of the DC ties to include the NERC Tag reference in the comments field on the ERCOT schedule request.
B. Between Western and Eastern Interconnections

The WSCC will use E-Tag for pre-scheduled transactions starting April 18, 2000, and for next hour and same day service wholly within WSCC starting October 17, 2000.

Due to the delay in implementing E-Tag for next hour and same day service, tagging requirements for these types of transactions shall remain unchanged within WSCC.

**During the interim period of April 18, 2000 through October 17, 2000**

- All INTERCHANGE TRANSACTIONS that cross the Interconnection Boundary, including next hour and same day service, will be submitted in E-Tag format for inclusion in the Eastern Interconnection IDC.

- PURCHASING-SELLING ENTITIES from WSCC submitting transactions shall provide E-Tag service or arrange for E-Tag services during this interim period.

- The submitting PURCHASING-SELLING ENTITY shall be responsible for the use of the WITHDRAW, CANCEL, TERMINATE, and REPLACEMENT features of E-Tag. The PURCHASING-SELLING ENTITY shall also be responsible for communicating the tag changes either by fax or telephone to all WSCC CONTROL AREAS and TRANSMISSION PROVIDERS on the Transaction Path.

- WSCC CONTROL AREAS and TRANSMISSION PROVIDERS on the Transaction Path that have E-Tag capability shall initiate the ADJUST feature of E-Tag as required. WSCC CONTROL AREAS and TRANSMISSION PROVIDERS on the Transaction Path that do not have E-Tag capability shall communicate either by telephone or fax with a CONTROL AREA or TRANSMISSION PROVIDER that does have E-Tag capability and arrange for the ADJUST message to be issued on their behalf.

- Any CONTROL AREA or TRANSMISSION PROVIDER that requested an adjust by E-Tag shall also be responsible for communicating the tag changes either by fax or telephone to all WSCC CONTROL AREAS and TRANSMISSION PROVIDERS on the Transaction Path.

**Interchange Transaction where the sink is in the Eastern Interconnection**

- The PURCHASING-SELLING ENTITY serving the load shall be responsible for submitting the E-Tag in accordance with Policy 3, Subsection A, Requirement 2. The PURCHASING-SELLING ENTITY shall also be responsible for communicating the tag information either by fax or telephone to all WSCC CONTROL AREAS and TRANSMISSION PROVIDERS on the Transaction Path.

- The PURCHASING-SELLING ENTITY responsible for submitting the E-Tag will be required to submit the E-Tag in accordance with the time requirements in Policy 3, Appendix 3A1, Subsection A – Eastern Interconnection.

- The TRANSMISSION PROVIDERS and CONTROL AREAS responsible for assessing the E-Tag will be required to assess the E-Tag in accordance with the time requirements in Policy 3, Appendix 3A1, Subsection A – Eastern Interconnection.
Interchange Transaction where the Sink is in the Western Interconnection

- For Pre-Scheduled Transactions, the PURCHASING-SELLING ENTITY serving the load shall be responsible for submitting the E-tag in accordance with Policy 3, Subsection A, Requirement 2. The PURCHASING-SELLING ENTITY shall also be responsible for communicating the tag information either by fax or telephone to all WSCC CONTROL AREAS and TRANSMISSION PROVIDERS on the Transaction Path.

- For Hourly/Multi-Hour Same Day Transactions, the sink PURCHASING-SELLING ENTITY in the Eastern Interconnection (last PSE before the DC Tie) shall be responsible for submitting the E-Tag in accordance with Policy 3, Subsection A, Requirement 2. The sink PURCHASING-SELLING ENTITY shall also be responsible for communicating the tag information either by fax or telephone to all WSCC CONTROL AREAS and TRANSMISSION PROVIDERS on the Transaction Path.

- The PURCHASING-SELLING ENTITY responsible for submitting the E-Tag will be required to submit the E-Tag in accordance with the time requirements in Policy 3, Appendix 3A1, Subsection B – Western Interconnection.

- The TRANSMISSION PROVIDERS and CONTROL AREAS responsible for assessing the E-Tag will be required to assess the E-Tag in accordance with the time requirements in Policy 3, Appendix 3A1, Subsection B – Western Interconnection.
Appendix 3A3 – Electronic Tagging Service Performance Requirements and Failure Procedures

Version 3

This document describes the performance requirements of the E-Tag System and the procedures to be followed in the event of an E-Tag System Component’s failure. Due to the importance of accurate information flow, these procedures and requirements have been developed to ensure that reliable data communications remain available at all times.

A. Performance Requirements

Tag Agent Service Requirements
Entities that are required to use Tag Agent Services are responsible for providing a Tag Agent Service with which to conduct business; there are no exemptions to this requirement. There is no specific requirement against which performance should be measured. However, in cases of Tag Agent Service failure, non-receipt of critical information (such as curtailment notifications, transaction denials, and schedule modifications) due to performance problems shall be the responsibility of the Tag Agent user.

While it is acceptable for an entity to contract with a third-party to provide for this requirement, it should be understood that the Tag Agent User is ultimately responsible for the provision of the service. The non-performance of a third party does not excuse the entity from the obligation to provide the service.

Tag Approval Services
Entities that are required to employ Tag Approval Services are responsible for providing a Tag Approval Service as well as providing a level of redundancy; there are no exemptions from this requirement. At a minimum, Tag Approval Services may not have greater than 1.0% of the tags sent to their system within a calendar month be recorded by Tag Authority Services as having a state of “COMM_FAIL.” While there is no specific level of redundancy that is required by this Appendix, sufficient redundancy must be in place that the entity is confident of achieving this standard.

While it is acceptable for an entity to contract with a third-party to provide for this requirement, it should be understood that the entity required to employ the Tag Approval Service is ultimately responsible for the provision of the service. The non-performance of a third party does not excuse the entity from the obligation to provide the service.

In order to monitor compliance with this requirement, the Control Areas will arrange with their Authority Services to generate compliance reports (in a format specified by NERC staff) at the beginning of each month determining this metric for the previous month on a Provider-by-Provider basis. NERC staff shall examine these results, investigate any violations, and post results based on this investigation as they are finalized.

Tag Authority Services
As the Tag Authority Service is the most critical element of the E-Tag System, it must meet much higher standards. These standards can be divided into two areas: Implementation, and Policies and Performance.
Appendix 3A3 – Electronic Tagging Service Failure Procedures

Implementation

Tag Authorities Services must be implemented in a manner that provides for redundancy and fault-tolerance through hardware and software; there are no exemptions to this requirement. Specifically, a Tag Authority Service must provide, at a minimum, the following:

- Two or more connections to the Internet, which may either be available concurrently or be switchable on demand (within five minutes);
- Redundant/Fault-Tolerant Networking Equipment between the Internet providers’ demarcation points and the Computer Systems, as well as between each of the components of the system required to be inter-networked to provide functionality (i.e., FDDI Rings, dual homing, etc…);
- Redundant/Fault-Tolerant Computer Systems that can immediately recover from a loss of any single component (i.e., mirrored databases, web clusters, etc…).

Providers of Tag Authority Services must furnish NERC staff with documented explanations of how they meet or exceed the above requirements. These documents shall be evaluated by NERC staff for fitness and held in confidence at the NERC Offices.

Policies and Performance

The following shall be required of all Tag Authority Services:

- All scheduled outages must be performed between the hours of 01:00 CST and 04:00 CST. Any maintenance that must be performed outside this three hour window must be accomplished though the use of redundant systems in such a manner that no outage is visible;
- Notice of Scheduled outages must be given to the public at least 24 hours before the outage is to occur. Notice shall be deemed valid if the following actions have been taken:
  1. Users of the system are sent notifications, via Email or a proprietary system, time stamped at least 24 hours prior to the outage;
  2. The NERC TISFORUM mailing list is sent Email notification time stamped at least 24 hours prior to the outage;
  3. The OASIS TSIN mailing list is sent Email notification time stamped at least 24 hours prior to the outage.

Any system problem that creates behavior contrary to that described in the E-Tag Specification shall constitute an “Unscheduled Outage.” For example, a system that begins rejecting every third message it receives due to a component failure in a cluster would constitute an Unscheduled Outage (although the system was only failing one third of the time, it was not performing as described in the E-Tag specification).

Tag Authority Services may not be in a state of Scheduled or Unscheduled outage for more than 0.5% of the time for the month, based on outage time (in minutes) for the month divided by total time in the month (in minutes). NERC staff may grant specific allowed outages to address special circumstances (i.e., scheduled specification changes, major internet outages, etc…).

While it is acceptable for an entity to contract with a third-party to provide for these requirements, it should be understood that the entity required to employ the Tag Authority Service is ultimately...
responsible for the provision of the service. The non-performance of a third party does not excuse the entity from the obligation to provide the service.

To monitor compliance with these requirements, the Operator of a Tag Authority System must submit to NERC staff, at the beginning of each month, a report describing outage activity for the previous month. This report shall consist of the following items:

1. The beginning of the outage;
2. The ending of the outage;
3. The type of outage (Scheduled or Unscheduled);
4. The nature of the outage (Maintenance, System Crash, etc…);
5. In the event of an Unscheduled Outage, the cause of the outage and the steps taken to ensure the problem has been addressed and will not reoccur.

NERC staff shall specify the electronic format in which to send these reports. These documents shall be evaluated by NERC staff and held in confidence at the NERC office. NERC staff shall develop statistics from these reports identifying system outage durations for each month. These preliminary findings will be held in confidence until NERC staff confirms them. These performance percentages shall be posted on the NERC web site, following confirmation by NERC staff, at the end of the month following the month evaluated.

Entities experiencing difficulty due to an Unnoticed Scheduled or Unscheduled Outage may send a Request for Investigation to NERC staff. This request should specify the estimated time the outage occurred, the estimated time the outage ended, and document evidence of the outage (such as TMP logs, email messages, etc…). NERC staff will investigate these claims with the appropriate Tag Authority Service Operator. Should a Tag Authority Service Operator be unable to refute the claim, and the Investigation Requestor appears to have provided an accurate representation of an undocumented outage, NERC staff may choose to modify calculated outage percentages to include the undocumented incident.
B. Failure Procedures

Backup procedures are needed because, in a communication system that operates on the public Internet, failures are certain to occur. The failures may be caused by as a result of overload of the network, loss of connection to an Internet service provider, corruption of one or more servers by computer hackers, failure of one or more entity’s Internet servers, internal firewall failure, and many other reasons.

Failures also have a wide variety of scopes. A failure may affect a single entity with a small number of schedules while all of its neighbors continue to operate normally, a small number of utilities in a local area, or a regional RTO with thousands of active schedules. However failures occur, the operation of the electric utility grid must continue. This document describes the manner in which operations are to be coordinated should such a failure become a reality.

Assumptions

A general assumption is that each operational entity in the electric utility industry has an internal energy management system, marketing system, or contract system that will not be affected by the Internet communication failure.

Actors

Tag Author – The entity that prepares and submits a schedule, normally a Purchasing Selling Entity.

Path Participant – Any of the entities that are part of a schedule transaction.

Authority Service entity – The entity that provides the Tag Authority Service for a tag. The Authority Service itself is a computer system that maintains the master database for the tag and communicates status with other computer systems. The Authority Service Entity is the utility industry entity that is responsible for providing the service. In E-Tag, this entity is the Load Control Area.

Approval Entity – An entity that has approval rights for a transaction. In E-Tag 1.7 this includes the transmission providers, scheduling control areas, generation providers, and load serving entities.

Checkout Partners – Any two entities in the utility industry that routinely perform a checkout confirmation of schedules for a period of time with each other. Most commonly two adjacent control areas checking net interchange. It might also be two marketers checking sales and purchases, or a transmission customer checking schedules with a transmission provider.

Failure Actions

When a failure occurs an entity will soon realize that it has lost communications with the other servers in the electronic tagging arena. Yet it must still communicate current energy flows across the transmission network and expected flows for the next few hours. Transmission curtailments must be accounted for in the sense that a required reduction in energy flows or increase in generation needs to be communicated. However, accounting issues will take a secondary priority to reliability issues in this exchange, and detail relating back to tags, schedules, and transmission reservations can be reconstructed later.

If adequate communication cannot be reestablished with other entities’ scheduling systems the last resort will be to control by frequency.
The table below lists typical failures that might occur and the emergency actions that the entity will take to compensate for that failure.

<table>
<thead>
<tr>
<th>Entity</th>
<th>Connectivity Problem</th>
<th>Backup actions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tag Author</td>
<td>Unable to submit tag to Authority Service.</td>
<td>Ask another entity in the transaction chain to submit the schedule for you. He then becomes the author.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Create a backup paper copy of the schedule and fax to authority service entity and all approval entities in the transaction.</td>
</tr>
<tr>
<td>Path Participant</td>
<td>Not receiving update messages.</td>
<td>Use Recovery Process to resynchronize from authority service.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Use telephone with Authority Service Entity to update status.</td>
</tr>
<tr>
<td>Authority Service Entity</td>
<td>Unable to send messages to generation or load control area.</td>
<td>Telephone Schedule Author to notify of the message failure. The author will fax the schedule to the Approval Entity for these control areas.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Telephone Approval Entity to notify of the message failure.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Approve or deny the schedule at the request of the Approval Entity (override).</td>
</tr>
<tr>
<td>Authority Service Entity</td>
<td>Unable to send messages to an approval entity for an intermediate Transmission Provider or Control Area.</td>
<td>Telephone Schedule Author to notify of the message failure. The author will fax the schedule to the Approval Entity.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Telephone Approval Entity to notify of the message failure.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Approve the schedule automatically.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Deny the schedule at the request of the Approval Entity (override).</td>
</tr>
<tr>
<td>Authority Service Entity</td>
<td>Unable to send messages to an information only entity.</td>
<td>No Action required.</td>
</tr>
<tr>
<td>Authority Service Entity</td>
<td>Unable to receive messages.</td>
<td>Broadcast a message by email or fax to all entities that use your authority service. The message should forecast a recovery time for your service.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>In the meantime, your Authority Service is down.</td>
</tr>
<tr>
<td>Approval Entity</td>
<td>Unable to receive messages from an authority service.</td>
<td>Use the Recovery Process to resynchronize from Authority Services or Central Repository.</td>
</tr>
<tr>
<td></td>
<td>(The Authority has an obligation to notify you and the authoring PSE.</td>
<td>Telephone the Authority Service entity with the approval or denial of the schedule.</td>
</tr>
<tr>
<td></td>
<td>The Authoring PSE has an obligation to fax the tag to the approver.)</td>
<td></td>
</tr>
<tr>
<td>Approval Entity</td>
<td>Unable to send messages to an authority service.</td>
<td>Telephone the Authority Service Entity with approval or denial of the schedule.</td>
</tr>
</tbody>
</table>
Appendix 3A3 – Electronic Tagging Service Failure Procedures

<table>
<thead>
<tr>
<th>Entity</th>
<th>Connectivity Problem</th>
<th>Backup actions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Checkout</td>
<td>Unable to exchange messages.</td>
<td>Telephone net exchange to the checkout partner.</td>
</tr>
<tr>
<td>Partner</td>
<td></td>
<td>Create a backup paper copy of the checkout data and fax to the checkout partner.</td>
</tr>
</tbody>
</table>

Notes:
1. The first action in every case is to attempt to establish connection by using an alternate communication method, a second Internet service provider, dial up connection, or a private network if one is available.
2. Next, the backup actions are attempted in the order specified.
3. The backup actions include printing paper reports from the internal energy management system. The reports include a schedule detail report for a short time period, net exchange between two operational entities, and transmission reservation usage between a transmission provider and a customer.
4. Every backup action list ends with a fax or telephone call that is completely independent of the public Internet.

Reports

Three reports have been designed to communicate energy flows and transmission reservation usage between partner entities with a tie where possible back to the schedules as known before the communication failure.

Net Exchange

A Net Exchange report is a paper summary of Interchange:

- The time span of the report will cover a period of the current hour to a few hours in the future, up to 24 hours.
- The entity and the partner entity are any two entities that share common schedules.
- The date and time are the date and time of the report.
- Net schedules are the net of schedules from and to the other entity.
- TO is a sum of the schedules from the entity to the partner entity.
- FROM is a sum of the schedules from the partner entity to the entity.
- Tag or fragment lines represent the data from each tag or fragment that was known at the time of the failure or has been entered later.
- Recent adjustment lines represent a summary of changes to the schedules that occurred since the failure.

Schedule Detail

A Schedule Detail report is a paper copy of an individual schedule. It includes:

- The schedule identification number and most current active revision number.
Appendix 3A3 – Electronic Tagging Service Failure Procedures

- The fully expanded energy schedule for a period of the current hour to a few hours in the future, up to 24 hours.

- The complete path with all OASIS and contract references.

**Reservation Usage**

A transmission Reservation Usage report is a summary of Reservation Usage:

- The time span of the report will cover a period of the current hour to a few hours in the future, up to 24 hours.

- The entities on the report are a transmission provider and a transmission contract holder.

- Gross reservations is the sum of reservations, Usage is the sum of usage.

- The detail lines are tag or fragment usage of reservation, organized by product and OASIS reservation number.

**Recovery Process**

The last backup issue is the recovery of current status when the communication link is reestablished. The recovery is accomplished by a query to the authority service for each entity that the entity does business with. The query returns a list of all the schedules that reference that entity with the schedule id, the current version number and the last modified date and time. The recovering entity then compares with its own database and updates his database to be current with the authority’s database. When all authority services have been queried, the recovery is complete.

If the entity desires, it can request a complete audit history of each schedule.
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| Net Schedules | xx | xx | xx | xx | xx | xx | xx | xx | ...
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Appendix 3A3 – Electronic Tagging Service Failure Procedures

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### Tag Detail Report – Example

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Revision: nnn

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**Physical Path**

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A3A3-10  
Approved by Board of Trustees:  
October 8, 2002
## Appendix 3A3 – Electronic Tagging Service Failure Procedures

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Version 3

Approved by Board of Trustees:
October 8, 2002
### Appendix 3A3 – Electronic Tagging Service Failure Procedures

<table>
<thead>
<tr>
<th>Service Point</th>
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#### Schedules

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#### Schedule

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### Appendix 3A3 – Electronic Tagging Service Failure Procedures

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# Electronic Tagging Reservation Usage Report – Example

|------------|----------|----------|----------|----------|----------|----------|----------|----------|----------|----------|

| Gross Reservations | yy       | yy       | yy       | yy       | yy       | yy       | yy       | yy       | yy       | yy       | ...
|---------------------|----------|----------|----------|----------|----------|----------|----------|----------|----------|----------|
| Usage               | xx       | xx       | xx       | xx       | xx       | xx       | xx       | xx       | xx       | xx       | ...

| Product | Assignment Ref | Reservation | xx       | xx       | yy       | yy       | yy       | yy       | yy       | yy       | yy       | ...
|---------|----------------|-------------|----------|----------|----------|----------|----------|----------|----------|----------|----------|
| Tag     | Revision       | Usage       | xx       | xx       | xx       | xx       | xx       | xx       | xx       | xx       | xx       | ...
| Tag ID  | xx             | xx          | xx       | xx       | xx       | xx       | xx       | xx       | xx       | xx       | xx       | ...
| Tag ID  | xx             | xx          | xx       | xx       | xx       | xx       | xx       | xx       | xx       | xx       | xx       | ...
| Tag ID  | xx             | xx          | xx       | xx       | xx       | xx       | xx       | xx       | xx       | xx       | xx       | ...
| Tag ID  | xx             | xx          | xx       | xx       | xx       | xx       | xx       | xx       | xx       | xx       | xx       | ...

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A3A3–15  
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October 8, 2002
### Appendix 3A3 – Electronic Tagging Service Failure Procedures

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</tr>
</tbody>
</table>

Version 3  
A3A3–16  
Approved by Board of Trustees:  
October 8, 2002
Appendix 3A4 – Required and Correctable Tag Data

Version 2

[Appendix 3D, “Transaction Tag Action”]

Appendix Subsections

A. New Transactions
B. Curtailments and Reloads (Reliability Profile Modifications)
C. Market Related Profile Modifications

A. New Transactions

A new TRANSACTION is a TRANSACTION that has not yet been implemented or confirmed for implementation. Such TRANSACTIONS must be presented to those entities that are responsible for the implementation of the TRANSACTION in order that they may evaluate the TRANSACTION request and determine whether or not the TRANSACTION can be implemented. The following information is to be used to describe such a TRANSACTION.

1. Market Information

1.1. Market Redispatch Information (only required if TRANSACTION is MRD TRANSACTION). (See “E-Tag Functional Specification Version 1.7”)

1.2. Financial Path (Required) – the description of financially responsible parties for the transaction in order. This will typically start with a Generation Providing Entity and finish with a LOAD SERVING ENTITY, with optionally Intermediate PURCHASING-SELLING ENTITIES between the two.

1.2.1. Energy Title Holder(s) (Required) – the identity of the entities financially responsible to take and/or deliver the energy as described in the physical path. This will typically be a Generation Providing Entity, a LOAD SERVING ENTITY, and optionally Intermediate PURCHASING-SELLING ENTITIES.

1.2.1.1. Energy Product Type (Correctable) – the type of energy delivered by the Energy Title Holder.

1.2.1.2. Contract Number(s) (Correctable) – reference to a TRANSACTION entered into by the Energy Title Holder with one or more other participants in the TRANSACTION.

1.2.1.3. Miscellaneous Information (Correctable) – information provided at the author’s option regarding the TRANSACTION.

2. Physical Information

2.1. Physical Path (Required) – the description of physically scheduling parties for the transaction in order and related to the financially responsible parties described above. This will always contain a Generation segment, at least one Transmission segment, and a LOAD segment.

2.1.1. Generation (Required) – set of data describing the physical and contractual characteristics of the energy source.

2.1.1.1. Resource Service Point (Required) – the physical point at which the energy is being generated. This may vary in granularity, dependent on local business practices.
Appendix 3A4 – Required Tag Data

A. New Transactions

2.1.1.2. Contract Number(s) (Correctable) – reference to a schedule or agreement entered into by the Generation Providing Entity and the Generator Operator.

2.1.1.3. Miscellaneous Information (Correctable) – information provided at the author’s option regarding the TRANSACTION.

2.1.1.4. Energy Profile (Required) – energy to be produced by the generator for this TRANSACTION.

2.1.2. Transmission (Required) – set of data describing the physical and contractual characteristics of a wheel (import, export, or through).

2.1.2.1. Transmission Provider (Required) – the identity of the transmission provider that is wheeling the energy.

2.1.2.2. Point of Receipt (Correctable) – valid Point of Receipt for scheduled Transmission Reservation.

- Point of Delivery (Correctable) – valid Point of Delivery for scheduled Transmission Reservation.

- Scheduling Entity(ies) (Correctable) – entities that are physically scheduling interchange on behalf of the TRANSMISSION PROVIDER in order to provide wheeling services. Typically the CONTROL AREA operator for the TRANSMISSION PROVIDER, but may be several CONTROL AREAS supporting a regional transmission service.

- Loss Provision Information (Required) (Correctable) – Information describing the manner in which losses are accounted when they are not scheduled as in-kind megawatt distributions through the original transaction. Types may be financial (paid in dollars based on tariff provisions), internal (scheduled in megawatts to the TRANSMISSION PROVIDER from a resource inside the TRANSMISSION PROVIDER’S CONTROL AREA), or external (scheduled in megawatts to the TRANSMISSION PROVIDER from a resource outside the TRANSMISSION PROVIDER’S CONTROL AREA). If internal or external, must specify contract numbers or TRANSACTION IDs.

- Miscellaneous Information (Correctable) – information provided at the author’s option regarding the transaction.

- POR and POD Profiles (Required) – schedule of Energy Flow imported at the Point of Receipt and Exported at the Point of Delivery.

- Transmission Reservation Number(s) (Required) (Correctable) – reference to a particular transmission reservation being used to provide transmission capacity to support the transaction being described.

  2.1.2.2.1. Transmission Product (Required) (Correctable) – Specifies the firmness of service associated with the transmission reservation being used.

  2.1.2.2.2. Transmission Customer (Required) (Correctable) – identifies the entity that purchased and holds the transmission reservation being presented for use.
A. New Transactions

2.1.2.2.3. Transmission Reservation Profile (Required) - information describing the transmission reservation commitment associated with the TRANSMISSION PROVIDER.

2.1.2.2.3.1. Committed Transmission Reservation Level (Required) – schedule of transmission reservation committed by the Transmission Customer for use for this TRANSACTION.

2.1.3. Load (Required) – set of data describing the physical and contractual characteristics of the energy sink.

2.1.3.1. Resource Service Point (Required) – the physical point at which the energy is being consumed. This may vary in granularity, dependent on local business practices.

2.1.3.2. Contract Number(s) (Correctable) – reference to a schedule or agreement entered into by the Load Serving Entity and the Load and/or Distributor.

2.1.3.3. Miscellaneous Information (Correctable) – information provided at the author’s option regarding the TRANSACTION.

2.1.3.4. Energy Profile (Required) – energy to be consumed by the load for this TRANSACTION.

Using Multiple Transmission Reservations to Support a Single Leg of an Interchange Transaction

The use of multiple transmission reservations to support a single leg of an INTERCHANGE TRANSACTION is known as transmission stacking. There are two types of transmission stacking:

- Vertical stacking, in which a Transmission Customer combines multiple reservations to achieve a certain net level of transmission capacity, and
- Horizontal stacking, in which a Transmission Customer combines multiple reservations to achieve a certain transmission capacity coverage over time.

The following diagrams illustrate these concepts more fully. In both cases, the assumed need is 100 MW of transmission capacity for hours 06:00 through 22:00.
Appendix 3A4 – Required Tag Data

A. New Transactions

Version 2 A3A4

Approved by Board of Trustees:
February 20, 2002

Vertical Stacking

Reservation 12345
(50MW from 6:00 – 22:00)

Reservation 67890
(50MW from 6:00 – 22:00)

Horizontal Stacking

Reservation 12345
(100 MW from 6:00 – 14:00)

Reservation 67890
(100 MW from 14:00 – 22:00)

Should a customer elect to utilize stacking to support their INTERCHANGE TRANSACTION, they must understand the following requirements:

- Stacks MUST be described through fully qualified profiles for each reservation being used
- At no point may the coverage described by the stack be less than the transmission capacity needed for the TRANSACTION’S energy flow
B. Curtailments and Reloads (Reliability Related Profile Modifications)

Curtailments and Reloads are special kinds of modifications to a transactions energy profile based on reliability concerns. Such modifications must be presented to those entities that are responsible for the implementation of the modification in order that they may evaluate the transaction request and determine whether or not the modification can be implemented. The following information must be used to describe such a modification.

- The TRANSACTION being curtailed or reloaded
- All necessary profile changes to set the maximum flow allowed for the transaction during the appropriate hours
- A contact person that initiated the curtailment or reload, and
- A description of the necessity for the schedule change.
C. Market-Related Profile Modifications

Profile Modifications are changes to a TRANSACTION’s energy profile based on market desires. Such modifications must be presented to those entities that are responsible for the implementation of the modification in order that they may evaluate the TRANSACTION request and determine whether or not the modification can be implemented. The following information must be used to describe such a modification.

- The TRANSACTION being modified
- All necessary profile changes to set the transmission capacity or energy flow to the desired levels during the appropriate hours, and
- A contact person that initiated the modification.
### For Eastern and Western Interconnections

The table below explains the various tag actions that are possible, and the entities that are entitled to initiate these actions:

<table>
<thead>
<tr>
<th>Desired Policy Action</th>
<th>Reason</th>
<th>Tagging Action</th>
<th>Initiated by</th>
<th>Result</th>
</tr>
</thead>
<tbody>
<tr>
<td>Approve a Tag Request</td>
<td>Economic, Reliability, or Contractual</td>
<td>Set Status (to Approved)</td>
<td>Approval Entity*</td>
<td>Approver indicates approval</td>
</tr>
<tr>
<td>Deny a Tag Request</td>
<td>Economic, Reliability, or Contractual</td>
<td>Set Status (to Denied)</td>
<td>Approval Entity*</td>
<td>Approval indicates denial</td>
</tr>
<tr>
<td>Study a Tag Request</td>
<td>Economic, Reliability, or Contractual</td>
<td>Set Status (to Studied)</td>
<td>Approval Entity*</td>
<td>Approval indicates the tag has been viewed, but have not committed to a decision</td>
</tr>
<tr>
<td>Withdraw a Tag Request</td>
<td>Economic</td>
<td>Withdraw Request prior to request implementation</td>
<td>Authoring PSE**</td>
<td>Request is dead</td>
</tr>
<tr>
<td>Cancel a New Tag</td>
<td>Economic</td>
<td>Request Profile Change – Set Energy and Capacity for the transaction to zero prior to transaction start</td>
<td>Authoring PSE**</td>
<td>Tag is dead</td>
</tr>
<tr>
<td>Terminate a Tag</td>
<td>Economic</td>
<td>Request Profile Change – Set Energy and capacity of the transaction to zero from a point of time forward</td>
<td>Authoring PSE**</td>
<td>Portion of tag is dead</td>
</tr>
<tr>
<td>Extend a Tag</td>
<td>Economic</td>
<td>Request Profile Change – Append additional hours onto an existing transaction</td>
<td>Authoring PSE**</td>
<td>Tag is extended</td>
</tr>
<tr>
<td>Reduce a Tag</td>
<td>Economic</td>
<td>Request Profile Change – Decrease Energy flow or Committed Transmission Reservation(s) for a transaction for a specific set of hours</td>
<td>Authoring PSE**, Market Operator***</td>
<td>Profile is Decreased</td>
</tr>
<tr>
<td>Increase a Tag</td>
<td>Economic</td>
<td>Request Profile Change – Increase Energy flow or Committed Transmission Reservation(s) for a transaction for a specific set of hours</td>
<td>Authoring PSE**, Market Operator***</td>
<td>Profile is Increased</td>
</tr>
</tbody>
</table>
### Appendix 3D – Transaction Tag Actions

<table>
<thead>
<tr>
<th>Desired Policy Action</th>
<th>Reason</th>
<th>Tagging Action</th>
<th>Initiated by</th>
<th>Result</th>
</tr>
</thead>
<tbody>
<tr>
<td>Curtail a Tag</td>
<td>Reliability (OSL Violation, Loss of Gen, loss of Load)</td>
<td>Request Profile Change – Limit Energy flow for a transaction for a specific set of hours</td>
<td>Generation CA, Load CA, Transmission Provider, Scheduling Entity</td>
<td>Profile is Decreased</td>
</tr>
<tr>
<td>Reload a Tag</td>
<td>OSL violation eliminated, Generator Returned, Load Returned</td>
<td>Request Profile Change – Release Limit of Energy flow for a transaction for a specific set of hours</td>
<td>Generation CA, Load CA, Transmission Provider, Scheduling Entity</td>
<td>Profile is Increased</td>
</tr>
</tbody>
</table>

**Notes:**

*Generation Providing Entities and LOAD-SERVING ENTITIES may elect to defer their approval rights to the HOST CONTROL AREA of their facilities. For more information, see GPE and LSE approval rights below.*

**In some situations, CONTROL AREAS implement certain INTERCHANGE TRANSACTIONS or INTERCHANGE SCHEDULES, such as bilateral inadvertent payback, DYNAMIC SCHEDULES, and emergency schedules from RESERVE SHARING GROUPS. In these situations, the CONTROL AREA serves as the PURCHASING-SELLING ENTITY and can perform these actions.**

***Entities registered as market operators and serving as either source or sink for a TRANSACTION may exercise such functions in order to indicate correct flow based on market clearing.***

**GPE and LSE Approval Rights**

GENERATION PROVIDING ENTITIES and LOAD-SERVING ENTITIES have been granted the right, but not the obligation, to approve TRANSACTION requests using their resources. If GPEs and LSEs specify an approval service in the Master Registry, then they are expected to approve/deny TRANSACTIONS when so requested. Otherwise, their HOST CONTROL AREA is expected to act on their behalf. The following table illustrates the proper way to interpret this requirement:

<table>
<thead>
<tr>
<th>If the PSE…</th>
<th>Specified an Approval URL</th>
<th>The PSE should be granted rights to approve or deny</th>
</tr>
</thead>
<tbody>
<tr>
<td>Did not specify an Approval URL</td>
<td>The CA should have proxy approval rights for the PSE</td>
<td></td>
</tr>
</tbody>
</table>
Appendix 4B – Electric System Security Data

Appendix Subsections
A. Electric System Security Data
B. Confidentiality Agreement for Electric System Security Data

Introduction
This Appendix lists the types of data that CONTROL AREAS are expected to provide, and RELIABILITY COORDINATORS are expected to share with each other as explained on Policy 4B, “System Coordination – Operational Security Information.”

A. Electric System Security Data

1. Information updated at least every ten minutes. The following information to be updated at least every ten minutes:

1.1. Transmission data. Transmission data for all Interconnections plus all other facilities considered key, from a reliability standpoint:

   1.1.1. Status
   1.1.2. MW or ampere loadings
   1.1.3. MVA capability
   1.1.4. Transformer tap and phase angle settings
   1.1.5. Key voltages

1.2. Generator data.

   1.2.1. Status
   1.2.2. MW and MVAR capability
   1.2.3. MW and MVAR net output
   1.2.4. Status of automatic voltage control facilities

1.3. Operating reserve

   1.3.1. MW reserve available within ten minutes

1.4. CONTROL AREA Demand

   1.4.1. Instantaneous

1.5. Interchange

   1.5.1. Instantaneous actual interchange with each CONTROL AREA.
   1.5.2. Current INTERCHANGE SCHEDULES with each CONTROL AREA by individual INTERCHANGE TRANSACTION, including INTERCHANGE identifiers, and reserve responsibilities.
   1.5.3. INTERCHANGE SCHEDULES for the next 24 hours

1.6. Area Control Error and Frequency
A. Electric System Security Data

1.6.1. Instantaneous area control error
1.6.2. Clock hour area control error
1.6.3. System frequency at one or more locations in the CONTROL AREA

2. Other operating information updated as soon as available

2.1. OPERATING SECURITY LIMITS in effect.
2.2. Forecast of operating reserve at peak, and time of peak for current day and next day.
2.3. Forecast peak demand for current day and next day.
2.4. Forecast changes in equipment status
2.5. New facilities in place
2.6. New or degraded special protection systems
2.7. Emergency operating procedures in effect
2.8. Severe weather, fire, or earthquake
2.9. Multi-site sabotage

3. Data retention. There are no requirements on any CONTROL AREA or Region to retain the data that they make available on the Interregional Security Network. Therefore, if the recipient of the data wishes to access historical data, it shall establish a method for saving the data it obtains from the Network.
B. Confidentiality Agreement for Electric System Security Data

Any changes to this “pro forma” Agreement by any Data Recipient must be approved by the NERC Operating Committee’s Operating Reliability Subcommittee.
North American Electric Reliability Council
Confidentiality Agreement for Electric System Security Data

Instructions

State or Province of Data Recipient (Item 12)
1. Insert the name of the state or province of your organization on the blank line in Item 12, “Governing Law.”

Signatory Page
2. Insert the name of your organization on the signatory page on the line labeled “OFFICER OF DATA RECIPIENT:”
3. Sign on line labeled “By:” and insert Officer’s title and signing date on next two lines.

Submission to NERC
4. Return two completed copies of the Agreement to the following address:

Donald M. Benjamin
Director of Operations
North American Electric Reliability Council
116-390 Village Blvd.
Princeton, NJ 08540
609-452-8060

One copy bearing the signature of an officer of NERC will be returned for your reference.
1. **Parties to this Agreement.** This Agreement is among the Data Recipients who are the signatories to this document, and between each of the Data Recipients and the North American Electric Reliability Council (NERC).

2. **Background.** To maintain the operational security of the bulk electric system, North American Electric Reliability Council Operating Policies require that specific information, which is referred to in this Agreement as “Electric System Security Data,” or simply as “Security Data,” regarding operating conditions within each CONTROL AREA be made available to other CONTROL AREAS, RELIABILITY COORDINATORS, and those entities responsible for real-time operational security. Because this Security Data can be competitively sensitive in the electric energy market, and is therefore considered proprietary in nature, the availability and confidentiality of this data must be protected in order to ensure that it is available only to those responsible for maintaining the operational security of the electricity supply in North America, and not made available nor used by any entities engaged in the Wholesale Merchant Function. This data will be exchanged among CONTROL AREAS and other entities who are directly responsible for the immediate, real-time operations of the bulk electric system. This data will be available only to those entities who are both 1) directly responsible for immediate real-time operational security, and 2) are also signatories to this Agreement. Any such entity is hereinafter referred to as a Data Recipient.

3. **Definitions.**

   3.1. **RELIABILITY COORDINATOR.** An entity responsible for the operational security of one or more CONTROL AREAS.

   3.2. **CONTROL AREA.** An electrical system bounded by interconnection (tie line) metering and telemetry. It controls its generation directly to maintain its interchange schedule with other CONTROL AREAS and contributes to frequency regulation of the Interconnection.

   3.3. **INTERCONNECTION.** When capitalized, any one of the four bulk electric system networks in North America: Eastern, Western, and ERCOT. When not capitalized, the facilities that connect two systems or CONTROL AREAS.

   3.4. **Restriction Period.** Security Data eight days or older is exempt from the access and disclosure restrictions of this Agreement. Forecast Security Data is exempt from the
access and disclosure restrictions of this Agreement beginning eight days after the forecast period has passed

3.5. **Security Data.** Information to be used for analyzing the operational security of the Interconnection. Security Data is available from RELIABILITY COORDINATORS or from the Interregional Security Network.

3.4.1. **Exception.** During the term of the Market Redispatch Pilot Program and with respect only to the flowgates included in the Pilot Program, Security Data shall exclude (1) actual flow and post-contingent flow and their respective limits for each flowgate included in the Pilot Program, and (2) generation shift factors for the generators relevant to the flowgates included in the Pilot Program, provided that such information is made available to the marketplace in a simultaneous and non-discriminatory manner.

3.6. **Data Supplier.** Entities who supply Security Data, either manually or automatically, to their RELIABILITY COORDINATOR(S), other RELIABILITY COORDINATORS, or other CONTROL AREAS. Examples include CONTROL AREAS, RELIABILITY COORDINATORS, and other entities who are directly responsible for the immediate, real-time operations of the bulk electric system.

3.7. **Data Recipient.** CONTROL AREAS, RELIABILITY COORDINATORS and other entities who are directly responsible for the immediate, real-time operations of the bulk electric system, who obtain Security Data, either manually or automatically, from their RELIABILITY COORDINATOR(S) or from the Interregional Security Network.

3.8. **Interregional Security Network.** The telecommunications and data system used to share operating information, including Security Data, among the Data Recipients.

3.9. **Wholesale Merchant Function.** The sale for resale of electric energy in interstate commerce.

3.10. **Merchant Employee.** Within an organization, any employee who engages in Wholesale Merchant Functions.

4. **Standards of Conduct.** A Data Recipient must conduct its business to conform with the following standards:

4.1. **General Rules.**
4.1.1. **Independence from Merchant Employees.** Except as emergency conditions dictate as discerned by a RELIABILITY COORDINATOR or CONTROL AREA system operator, the employees of a Data Recipient who receive Security Data and are responsible for real-time operational security must function independently of the Merchant Employees within that organization or its affiliates.

4.1.2. **Emergencies.** Notwithstanding any other provisions herein, in emergency circumstances that could jeopardize operational security, Data Recipients may take whatever steps are necessary to maintain system security. Data Recipients must report to the RELIABILITY COORDINATOR each emergency that resulted in any deviation from this Agreement within 24 hours of such deviation.

4.2. **Employee Conduct.**

4.2.1. **Prohibitions.** Any Merchant Employee of the Data Recipient or its affiliate, engaged in Wholesale Merchant Functions, is prohibited from having access to the Security Data received from other entities.

4.2.2. **Employee Transfers.** Employees engaged in either the Wholesale Merchant Function (Merchant Employees) or the real-time transmission system operations reliability function are not precluded from transferring between functions as long as the transfer is not used as a means to circumvent the standards of this Agreement. Notice of any employee transfer between reliability and Wholesale Merchant Functions shall be provided on the Open Access Same-Time Information System and to the RELIABILITY COORDINATOR at least 24 hours prior to the effective date of the transfer. The information to be posted must include the name of the transferring employee, the respective titles held while performing each function, and the effective date of the transfer. The information posted under this section shall remain on the OASIS for 90 days.

4.2.3. **Disclosure.** Employees of the Data Recipient or employees of an affiliate who are engaged in transmission system operation reliability functions shall not disclose to Merchant Employees of the Data Recipient any Security Data received from other entities, except as compelled by law or judicial or regulatory order or directive.

4.2.3.1. The Data Recipient shall not, even under conditions of confidence, make available, disclose, provide, or communicate any Security Data to any
other party who is not a signatory to this Agreement except as compelled by law or judicial or regulatory order or directive. The Data Recipient agrees to exercise all reasonable efforts against the compelled disclosure of Security Data to any party who is not a signatory to this Agreement.

4.2.4. Compliance. The Data Recipient must educate its employees, and employees of an affiliate engaged in transmission system operations, in the provisions of this Agreement and provide any information upon request to the RELIABILITY COORDINATOR necessary to determine compliance with the terms and conditions of this Agreement, including confidentiality agreements that include the provisions of this Agreement.

5. Disclaimer. Each Data Recipient assumes any and all risk and responsibility for selection and use of, and reliance on, any Security Data.

6. Hold harmless. Each Data Recipient acknowledges and agrees that the Data Supplier generates and gathers such operating Security Data to meet the Data Supplier's sole needs and responsibilities. Each Data Recipient receives any and all Security Data “as is” and with all faults, errors, defects, inaccuracies, and omissions. No Data Supplier makes any representations or warranties whatsoever with respect to the availability, timeliness, accuracy, reliability, or suitability of any Security Data pursuant to this Agreement. Each Data Recipient disclaims and waives all rights and remedies that it may otherwise have with respect to all warranties and liabilities of each Data Supplier, expressed or implied, arising by law or otherwise, with respect to any faults, errors, defects, inaccuracies or omissions in, or availability, timeliness, reliability or suitability of the Security Data. Each Data Recipient assumes any and all risk and responsibility for selection and use of, and reliance on, any Security Data. By entering into this Agreement, each Data Recipient does not hold itself out to provide like or similar service to any other entity. Each Data Recipient acknowledges and agrees that NERC has established the Interregional Security Network to facilitate maintenance of operational security by the RELIABILITY COORDINATOR and other CONTROL AREAS, and that the supply and use of data in accordance with this Agreement is the responsibility of the individual Data Recipients and Data Suppliers and not of NERC. NERC makes no representations or warranties whatsoever with respect to the availability, timeliness, accuracy, reliability, or suitability of any Security Data provided pursuant to this Agreement. Each Data Supplier and Data Recipient disclaims and waives any rights or remedies that it might otherwise have against NERC for faults, errors, defects, inaccuracies, or omissions in, or availability, timeliness, accuracy, reliability or suitability of the Security Data.
Further, each Data Supplier and Data Recipient disclaims and waives any rights or remedies that it might otherwise have against NERC for the neglect, wrongful, or unauthorized use or disclosure of the Security Data by any Data Recipient or Data Supplier.

7. Term and Termination.

7.1. Term. The term of this Agreement shall commence immediately upon the signatures of an officer of the Data Recipient and officer of NERC and shall remain in effect until terminated.

7.2. Termination. Any Data Recipient wishing to terminate this Agreement shall notify NERC in writing of its desire to terminate this Agreement. Termination shall be effective 30 days following acknowledgment of receipt of such written notice. Upon such termination the Data Recipient will be prohibited from further receipt of the Security Data.

7.2.1. Termination does not excuse the Data Recipient from supplying Security Data if required in NERC Operating Policies.

7.2.2. Termination does not excuse the Data Recipient from holding confidential any forecast Security Data before the forecast period has passed.

8. Governmental Authority. This Agreement is subject to the laws, rules, regulations, orders and other requirements, now or hereafter in effect, of all regulatory authorities having jurisdiction over the Security Data, this Agreement, the Data Suppliers, and the Data Recipients. All laws, ordinances, rules, regulations, orders and other requirements, now or hereafter in effect, of governmental authorities that are required to be incorporated in agreements of this character are by this reference incorporated in this Agreement.

9. Non-compliance. Data Recipients found not to be in compliance with this Agreement by NERC or any other Data Recipient will be prohibited from further receipt of the Security Data from its RELIABILITY COORDINATOR(S) or the Interregional Security Network until NERC determines that the Data Recipient has resumed compliance with this Agreement. Non-compliance does not excuse the Data Recipient from supplying Security Data if required in NERC Operating Policies, nor does it excuse the Data Recipient from holding confidential any forecast Security Data before the forecast period has passed.

10. Due Diligence. All signatories to this Agreement shall use due diligence to protect the Interregional Security Network and Security Data from improper access.
B. Confidentiality Agreement for Electric System Security Data

11. **Disputes.** Disputes arising over issues regarding this Agreement will be settled in accordance with the dispute resolution procedures of the Data Recipient’s Regional Council and the North American Electric Reliability Council.

12. **Governing Law.** This Agreement shall in all respects be interpreted, construed and enforced in accordance with the laws of ___________________________ (the state(s) or province(s) of the Data Recipient), without reference to rules governing conflicts of law, except to the extent such laws may be preempted by the laws of the United States of America, Canada, or Mexico as applicable.

13. **Integration.** This Agreement constitutes the entire Agreement of the parties.

OFFICER OF DATA RECIPIENT:

By: 

Title: 

Date: 

OFFICER OF NERC

By: 

Title: 

Date:
Appendix 5C – Energy Emergency Alerts
Version 2, Draft 4

Appendix Sections
A. General Requirements
B. Energy Emergency Alert Levels
C. Energy Emergency Alert 3 Report

Introduction
This Appendix provides the procedures by which a Load-Serving Entity can obtain capacity and energy when it has exhausted all other options and can no longer provide its customers’ expected energy requirements. NERC defines this situation as an “Energy Emergency.” NERC assumes that a capacity deficiency will manifest itself as an energy emergency.

The Energy Emergency Alert Procedure is initiated by the LSE’s RELIABILITY COORDINATOR, who declares various Energy Emergency Alert levels as defined in Section B, “Energy Emergency Alert Levels” to provide assistance to the LSE.

The LSE who requests this assistance is referred to as an “Energy Deficient Entity.”

NERC recognizes that Transmission Providers are subject to obligations under FERC-approved tariffs and other agreements, and nothing in these procedures should be interpreted as changing those obligations.
A. General Requirements

1. **Initiated only by Reliability Coordinator.** An Energy Emergency Alert may be initiated only by a RELIABILITY COORDINATOR at 1) the RELIABILITY COORDINATOR’S own request, or 2) upon the request of a CONTROL AREA, or 3) upon the request of a LOAD SERVING ENTITY. The cost of available resources shall not be a consideration for initiating an alert.

   1.1. **Situations for initiating Alert.** An Energy Emergency Alert may be initiated for the following reasons:

   - When the LSE is, or expects to be, unable to provide its customers’ energy requirements, and has been unsuccessful in locating other systems with available resources from which to purchase, or
   - The LSE cannot schedule the resources due to, for example, ATC limitations or transmission loading relief limitations.

2. **Notification.** A RELIABILITY COORDINATOR who declares an Energy Emergency Alert shall notify all CONTROL AREAS and TRANSMISSION PROVIDERS in his RELIABILITY AREA. The RELIABILITY COORDINATOR shall also notify all other RELIABILITY COORDINATORS of the situation via the Reliability Coordinator Information System (RCIS). Additionally, conference calls between RELIABILITY COORDINATORS shall be held as necessary to communicate system conditions. The RELIABILITY COORDINATOR shall also notify the other RELIABILITY COORDINATORS when the Alert has ended.
B. Energy Emergency Alert Levels

Introduction
To ensure that all RELIABILITY COORDINATORS clearly understand potential and actual energy emergencies in the INTERCONNECTION, NERC has established three levels of Energy Emergency Alerts. The RELIABILITY COORDINATORS will use these terms when explaining energy emergencies to each other. An Energy Emergency Alert is an emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC Operating Policies or power supply contracts.

The RELIABILITY COORDINATOR may declare whatever Alert level is necessary, and need not proceed through the alerts sequentially.

1. Alert 1 – All available resources in use.

Circumstances:

• CONTROL AREA, RESERVE SHARING GROUP, or LOAD SERVING ENTITY foresees or is experiencing conditions where all available resources are committed to meet firm load, firm transactions, and reserve commitments, and is concerned about sustaining its required OPERATING RESERVES, and

• Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed

2. Alert 2 – Load management procedures in effect.

Circumstances:

• CONTROL AREA, RESERVE SHARING GROUP, or LOAD SERVING ENTITY is no longer able to provide its customers’ expected energy requirements, and is designated an ENERGY DEFICIENT ENTITY.

• ENERGY DEFICIENT ENTITY foresees or has implemented procedures up to, but excluding, interruption of firm load commitments. When time permits, these procedures may include, but are not limited to:
  • Public appeals to reduce demand
  • Voltage reduction
  • Interruption of non-firm end use loads in accordance with applicable contracts1
  • Demand-side management
  • Utility load conservation measures

During Alert 2, RELIABILITY COORDINATORS, CONTROL AREAS, and ENERGY DEFICIENT ENTITIES have the following responsibilities:

2.1 Notifying other Control Areas and Market Participants. The ENERGY DEFICIENT ENTITY shall communicate its needs to other CONTROL AREAS and market participants.

1 For emergency, not economic, reasons.
Upon request from the ENERGY DEFICIENT ENTITY, the respective RELIABILITY COORDINATOR shall post the declaration of the Alert level along with the name of the ENERGY DEFICIENT ENTITY and, if applicable, its CONTROL AREA on the NERC Web site

2.2 Declaration Period. The ENERGY DEFICIENT ENTITY shall update its RELIABILITY COORDINATOR of the situation at a minimum of every hour until the Alert 2 is terminated. The RELIABILITY COORDINATOR shall update the energy deficiency information posted on the NERC web site as changes occur and pass this information on to the affected RELIABILITY COORDINATORS, CONTROL AREAS, and Transmission Providers.

2.3 Sharing information on resource availability. CONTROL AREAS and market participants with available resources shall immediately contact the ENERGY DEFICIENT ENTITY. This should include the possibility of selling non-firm (recallable) energy out of available operating reserves. The ENERGY DEFICIENT ENTITY shall notify the RELIABILITY COORDINATORS of the results.

2.4 Evaluating and mitigating transmission limitations. The RELIABILITY COORDINATORS shall review all OPERATING SECURITY LIMITS and transmission loading relief procedures in effect that may limit the ENERGY DEFICIENT ENTITY’s scheduling capabilities. Where appropriate, the RELIABILITY COORDINATORS shall inform the Transmission Providers under their purview of the pending ENERGY EMERGENCY and request that they increase their Available Transfer Capability (ATC) by actions such as restoring transmission elements that are out of service, reconfiguring their transmission system, adjusting phase angle regulator tap positions, implementing emergency operating procedures, and reviewing generation redispatch options.

2.4.1 Notification of ATC adjustments. Resulting increases in ATCs shall be simultaneously communicated to the ENERGY DEFICIENT ENTITY and the market via posting on the appropriate OASIS sites by the Transmission Providers.

2.4.2 Availability of generation redispatch options. Available generation redispatch options shall be immediately communicated to the ENERGY DEFICIENT ENTITY by its RELIABILITY COORDINATOR.

2.4.3 Evaluating impact of current transmission loading relief events. The RELIABILITY COORDINATORS shall evaluate the impact of any current transmission loading relief events on the ability to supply emergency assistance to the ENERGY DEFICIENT ENTITY. This evaluation shall include analysis of system security and involve close communication among RELIABILITY COORDINATORS and the ENERGY DEFICIENT ENTITY.

2.4.4 Initiating inquiries on reevaluating OPERATING SECURITY LIMITS. The RELIABILITY COORDINATORS shall consult with the CONTROL AREAS and Transmission Providers in their RELIABILITY AREAS about the possibility of reevaluating and revising OPERATING SECURITY LIMITS.

2.5 Coordination of emergency responses. The RELIABILITY COORDINATOR shall communicate and coordinate the implementation of emergency operating responses.
B. Energy Emergency Alert Levels

2.6 **ENERGY DEFICIENT ENTITY actions.** Before declaring an Alert 3, the ENERGY DEFICIENT ENTITY must make use of all available resources. This includes but is not limited to:

2.6.1 **All available generation units are on line.** All generation capable of being on line in the time frame of the emergency is on line including quick-start and peaking units, regardless of cost.

2.6.2 **Purchases made regardless of cost.** All firm and non-firm purchases have been made, regardless of cost.

2.6.3 **Non-firm sales recalled and contractually interruptible loads and DSM curtailed.** All non-firm sales have been recalled, contractually interruptible retail loads curtailed, and Demand-side Management activated within provisions of the agreements.

2.6.4 **Operating Reserves.** Operating reserves are being utilized such that the ENERGY DEFICIENT ENTITY is carrying reserves below the required minimum or has initiated emergency assistance through its operating reserve sharing program.

3. **Alert 3 – Firm load interruption imminent or in progress.**

Circumstances:

- CONTROL AREA or LOAD SERVING ENTITY foresees or has implemented firm load obligation interruption. The available energy to the ENERGY DEFICIENT ENTITY, as determined from Alert 2, is only accessible with actions taken to increase transmission transfer capabilities.

3.1 **Continue actions from Alert 2.** The RELIABILITY COORDINATORS, and the ENERGY DEFICIENT ENTITY, shall continue to take all actions initiated during Alert 2. If the emergency has not already been posted on the NERC web site (see paragraph 2.1), the respective RELIABILITY COORDINATORS will, at this time, post on the web site information concerning the emergency.

3.2 **Declaration Period.** The ENERGY DEFICIENT ENTITY shall update its RELIABILITY COORDINATOR of the situation at a minimum of every hour until the Alert 3 is terminated. The RELIABILITY COORDINATOR shall update the energy deficiency information posted on the NERC web site as changes occur and pass this information on to the affected RELIABILITY COORDINATORS (via the RCIS), CONTROL AREAS, and Transmission Providers.

3.3 **Use of Transmission short-time limits.** The RELIABILITY COORDINATORS shall request the appropriate Transmission Providers within their RELIABILITY AREA to utilize available short-time transmission limits or other emergency operating procedures in order to increase transfer capabilities into the ENERGY DEFICIENT ENTITY.

3.4 **Reevaluating and revising OPERATING SECURITY LIMITS.** The RELIABILITY COORDINATOR of the ENERGY DEFICIENT ENTITY shall evaluate the risks of revising OPERATING SECURITY LIMITS on the reliability of the overall transmission system. Reevaluation of OPERATING SECURITY LIMITS shall be coordinated with other RELIABILITY COORDINATORS and only with the agreement of the CONTROL AREA or Transmission Provider whose equipment would be affected. The resulting increases in
transfer capabilities shall only be made available to the ENERGY DEFICIENT ENTITY who has declared an Energy Emergency Alert 3 condition. OPERATING SECURITY LIMITS shall only be revised as long as an Alert 3 condition exists or as allowed by the CONTROL AREA or Transmission Provider whose equipment is at risk. The following are minimum requirements that must be met before OPERATING SECURITY LIMITS are revised:

3.4.1 ENERGY DEFICIENT ENTITY obligations. The deficient CONTROL AREA or LOAD SERVING ENTITY must agree that, upon notification from its RELIABILITY COORDINATOR of the situation, it will immediately take whatever actions are necessary to mitigate any undue risk to the INTERCONNECTION. These actions may include load shedding.

3.4.2 Mitigation of cascading failures. The RELIABILITY COORDINATOR shall use his best efforts to ensure that revising OPERATING SECURITY LIMITS would not result in any cascading failures within the INTERCONNECTION.

3.5 Returning to pre-emergency OPERATING SECURITY LIMITS. Whenever energy is made available to an ENERGY DEFICIENT ENTITY such that the transmission systems can be returned to their pre-emergency OPERATING SECURITY LIMITS, the ENERGY DEFICIENT ENTITY shall notify its respective RELIABILITY COORDINATOR and downgrade the Alert.

3.5.1 Notification of other parties. Upon notification from the ENERGY DEFICIENT ENTITY that an Alert has been downgraded, the RELIABILITY COORDINATOR shall notify the affected RELIABILITY COORDINATORS (via the RCIS), CONTROL AREAS, and Transmission Providers that their systems can be returned to their normal OPERATING SECURITY LIMITS.

3.6 Reporting. Any time an Alert 3 is declared, the ENERGY DEFICIENT ENTITY shall complete the report listed in appendix 9B, Section C and submit this report to its respective RELIABILITY COORDINATOR within two business days of downgrading or termination of the Alert. Upon receiving the report, the RELIABILITY COORDINATOR shall review it for completeness and immediately forward it to the NERC staff for posting on the NERC web site. The RELIABILITY COORDINATOR shall present this report to the Reliability Coordinator Working Group at its next scheduled meeting.

4. Alert 0 - Termination. When the ENERGY DEFICIENT ENTITY believes it will be able to supply its customers’ energy requirements, it shall request of his RELIABILITY COORDINATOR that the EEA be terminated.

4.1. Notification. The RELIABILITY COORDINATOR shall notify all other RELIABILITY COORDINATORS via the RCIS of the termination. The RELIABILITY COORDINATOR shall also notify the affected CONTROL AREAS and TRANSMISSION PROVIDERS. The Alert 0 shall also be posted on the NERC web site if the original Alert was so posted.
C. Energy Emergency Alert 3 Report

NERC Policy 9B section B paragraph 3.5 requires that a Deficient Control Area or Load Serving Entity declaring an Energy Emergency Alert 3 must complete the following report. Upon completion of this report it is to be sent to the RELIABILITY COORDINATOR for review within two business days of the incident.

Requesting Control Area:

Entity experiencing energy deficiency (if different from Control Area):

Date/Time Implemented:

Date/Time Released:

Declared Deficiency Amount (MW):

Total Energy supplied by other Control Areas During the Alert 3 period:

Conditions that precipitated call for “Energy Deficiency Alert 3”: 
If “Energy Deficiency Alert 3” had not been called, would firm load be cut? if no, explain:

Explain what action was taken in each step to avoid calling for “Energy Deficiency Alert 3”:

1. All generation capable of being on line in the time frame of the energy deficiency was on line (including quick start and peaking units) without regard to cost.

2. All firm and nonfirm purchases were made regardless of cost.

3. All nonfirm sales were recalled within provisions of the sale agreement.
4. Interruptible load was curtailed where either advance notice restrictions were met or the interruptible load was considered part of spinning reserve.

5. Available load reduction programs were exercised (public appeals, voltage reductions, etc.).

6. Operating Reserves being utilized.

Comments:

Reported By: Organization:
Title:
Appendix 5F — Reporting Requirements for Major Electric System Emergencies

Appendix Subsections
A. NERC Disturbance Reporting Requirements
B. NERC Operating Security Limit and Preliminary Disturbance Report
C. U.S. Department of Energy Disturbance Reporting Requirements

A. NERC Disturbance Reporting Requirements

Introduction
These disturbance reporting requirements apply to all entities using the electric transmission systems in North America and provide a common basis for all NERC disturbance reporting. The utility or other electricity supply entity on whose system a disturbance that must be reported occurs shall notify NERC and its Regional Council of the disturbance using the NERC Operating Security Limit and Preliminary Disturbance Report forms (see Attachment 1 – Summary of NERC and DOE Reporting Requirements for Major Electric System Emergencies). Reports can be sent to NERC via email (info@nerc.com) or by facsimile (609-452-9550) using the NERC Operating Security Limit and Preliminary Disturbance Report forms. If a disturbance is to be reported to DOE also, the responding entity may use the DOE reporting form when reporting to NERC. Note: All Emergency Incident and Disturbance Reports (Schedules 1 and 2) sent to DOE shall be simultaneously sent to NERC, preferably electronically, at info@nerc.com.

The NERC Operating Security Limit and Preliminary Disturbance Reports are to be made as specified in Policy 5F for any of the following events:

1. The loss of a bulk power transmission component that significantly affects the integrity of interconnected system operations. Generally, a disturbance report will be required if the event results in actions such as:

   1.1. Modification of operating procedures; or

   1.2. Modification of equipment (e.g. control systems or special protection systems) to prevent reoccurrence of the event; or

   1.3. Identification of valuable lessons learned; or

   1.4. Identification of non-compliance with NERC standards or policies; or

   1.5. Identification of a disturbance that is beyond recognized criteria, i.e. three-phase fault with breaker failure, etc.; or

   1.6. Frequency or voltage going below the under-frequency or under-voltage load shed points.

2. The occurrence of an interconnected system separation or system islanding or both.

3. Loss of generation by a utility or generation supply entity — 2,000 MW or more in the Eastern Interconnection or Western Interconnection and 1,000 MW or more in the ERCOT Interconnection.
4. Equipment failures/system operational actions, which result in the loss of firm system demands for more than 15 minutes, as described below:

   4.1. Entities with a previous year recorded peak demand of more than 3,000 MW are required to report all such losses of firm demands totaling more than 300 MW.

   4.2. All other entities are required to report all such losses of firm demands totaling more than 200 MW or 50% of the total customers being supplied immediately prior to the incident, whichever is less.

5. Firm load shedding of 100 MW or more to maintain the continuity of the bulk electric system.

6. Any system operation or operator action resulting in:

   6.1. Sustained voltage excursions equal to or greater than ±10%, or

   6.2. Major damage to power system components, or

   6.3. Failure, degradation, or misoperation of system protection, special protection schemes, remedial action schemes, or other operating systems that do not require system operator intervention, which did result in or could have resulted in a system disturbance as defined by steps 1 through 5 above.


8. Any event that the Operating Reliability Subcommittee chairman requests be submitted to Disturbance Analysis Working Group (DAWG) for review because of the nature of the disturbance and the insight and lessons the electricity supply and delivery industry could learn.
## B. NERC Operating Security Limit and Preliminary Disturbance Report

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<table>
<thead>
<tr>
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<tbody>
<tr>
<td>1.</td>
<td>Organization filing report</td>
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<tr>
<td>2.</td>
<td>Name of person filing report</td>
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<tr>
<td>3.</td>
<td>Telephone number</td>
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<tr>
<td>4.</td>
<td>Date and time of disturbance</td>
</tr>
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<td></td>
<td>Time/Zone</td>
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<td>5.</td>
<td>Did disturbance originate in your system?</td>
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<tr>
<td>6.</td>
<td>Describe disturbance including: cause, equipment damage, critical services interrupted, system separation, key scheduled and actual flows prior to disturbance and in the case of a disturbance involving a special protection or remedial action scheme, what action is being taken to prevent recurrence</td>
</tr>
<tr>
<td>7.</td>
<td>List generation tripped</td>
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<td>8.</td>
<td>Frequency</td>
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<td></td>
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<tr>
<td>9.</td>
<td>List transmission lines tripped (specify voltage level of each line)</td>
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<tr>
<td>10.</td>
<td>Demand tripped and number of customers affected</td>
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<td></td>
<td>Demand lost in MW-Minutes</td>
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<td></td>
<td>Customers</td>
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<td></td>
<td>MW-Min.</td>
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<tr>
<td>11.</td>
<td>Restoration time</td>
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<td></td>
<td>Transmission</td>
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<tr>
<td></td>
<td>Generation</td>
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<td></td>
<td>Demand</td>
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</tbody>
</table>
C. U.S. Department of Energy Disturbance Reporting Requirements

Introduction
The Department of Energy (DOE), under its relevant authorities, has established mandatory reporting requirements for electric emergency incidents and disturbances in the United States. DOE collects this information from the electric power industry on Form EIA-417 to meet its overall national security and Federal Energy Management Agency’s Federal Response Plan (FRP) responsibilities. DOE will use the data from this form to obtain current information regarding emergency situations on U.S. electric energy supply systems. DOE’s Energy Information Administration (EIA) will use the data for reporting on electric power emergency incidents and disturbances in monthly EIA reports. In addition, the data may be used to develop legislative recommendations, reports to the Congress and as a basis for DOE investigations following severe, prolonged, or repeated electric power reliability problems.

Who must report
Every electric utility that operates a CONTROL AREA, and/or RELIABILITY COORDINATORS, and other electric utilities, as appropriate, must use this form to submit mandatory reports of electric power system incidents or disturbances to the DOE Operations Center that operates on a 24-hour basis, seven days a week. However, all electric utilities also have filing responsibilities to provide information to CONTROL AREA operators when necessary for their reporting obligations and to file form EIA-417 in cases where a CONTROL AREA operator will not be involved. EIA requests that it be notified for those that plan to file jointly and of those electric utilities that want to file separately.

Special reporting provisions exist for those electric utilities located within the United States, but for whom control area oversight responsibilities are handled by electrical systems located across in international border. A foreign utility handling U.S. CONTROL AREA responsibilities, may wish to file this information voluntarily to the DOE. Any U.S.-based utility in this international situation needs to inform DOE that these filings will come from a foreign-based electric system or file the required reports themselves.

When to report
Form EIA-417 must be submitted to the DOE Operations Center if any one of the following applies (see Attachment 1 – Summary of NERC and DOE Reporting Requirements for Major Electric System Emergencies):

1. Uncontrolled loss of 300 MW or more of firm system load for more than 15 minutes from a single incident.
2. Load shedding of 100 MW or more implemented under emergency operational policy.
3. System-wide voltage reductions of 3% or more.
4. Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system.
5. Actual or suspected physical attacks that could impact electric power system adequacy or reliability; or vandalism, which target components of any security system. Actual or suspected cyber or communications attacks that could impact electric power system adequacy or vulnerability.
6. Actual or suspected cyber or communications attacks that could impact electric power system adequacy or vulnerability.
7. Fuel supply emergencies that could impact electric power system adequacy or reliability.
8. Loss of electric service to more than 50,000 customers for one hour or more.
Appendix 5F — Reporting Requirements for Major Electric System Emergencies

9. Complete operational failure or shut-down of the transmission and/or distribution electrical system

When to submit
The initial DOE Emergency Incident and Disturbance Report (form EIA-417 – Schedule 1) shall be submitted to the DOE Operations Center within 60 minutes of the time of the system disruption. Complete information may not be available at the time of the disruption. However, provide as much information as is known or suspected at the time of the initial filing. If the incident is having a critical impact on operations, a telephone notification to the DOE Operations Center (202-586-8100) is acceptable, pending submission of the completed form EIA-417. Electronic submission via an on-line web-based form is the preferred method of notification. However, electronic submission by facsimile or email is acceptable.

An updated form EIA-417 (Schedule 1 and 2) is due within 48 hours of the event to provide complete disruption information. Electronic submission via facsimile or email is the preferred method of notification.

Detailed DOE Incident and Disturbance reporting requirements can be found at:
http://www.eia.doe.gov/cneaf/electricity/page/form_417.html
### Attachment 1 – Summary of NERC and DOE Reporting Requirements for Major Electric System Emergencies

<table>
<thead>
<tr>
<th>Incident No.</th>
<th>Incident</th>
<th>Threshold</th>
<th>Report Required</th>
<th>Time</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Uncontrolled loss of Firm System Load</td>
<td>≥ 300 MW – 15 minutes or more</td>
<td>EIA – Sch-1 EIA – Sch-2</td>
<td>1 hour</td>
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<td></td>
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<td>48 hour</td>
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<td>2</td>
<td>Load Shedding</td>
<td>≥ 100 MW under emergency operational policy</td>
<td>EIA – Sch-1 EIA – Sch-2</td>
<td>1 hour</td>
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<td></td>
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<td>48 hour</td>
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<td>3</td>
<td>Voltage Reductions</td>
<td>3% or more – applied system-wide</td>
<td>EIA – Sch-1 EIA – Sch-2</td>
<td>1 hour</td>
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<td>48 hour</td>
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<tr>
<td>4</td>
<td>Public Appeals</td>
<td>Emergency conditions to reduce demand</td>
<td>EIA – Sch-1 EIA – Sch-2</td>
<td>1 hour</td>
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<td>48 hour</td>
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<tr>
<td>5</td>
<td>Physical sabotage, terrorism or vandalism</td>
<td>On physical security systems – suspected or real</td>
<td>EIA – Sch-1 EIA – Sch-2</td>
<td>1 hour</td>
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<td></td>
<td></td>
<td></td>
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<td>48 hour</td>
</tr>
<tr>
<td>6</td>
<td>Cyber sabotage, terrorism or vandalism</td>
<td>If the attempt is believed to have or did happen</td>
<td>EIA – Sch-1 EIA – Sch-2</td>
<td>1 hour</td>
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<td></td>
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<td>48 hour</td>
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<tr>
<td>7</td>
<td>Fuel supply emergencies</td>
<td>Fuel inventory or hydro storage levels ≤ 50% of normal</td>
<td>EIA – Sch-1 EIA – Sch-2</td>
<td>1 hour</td>
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<td></td>
<td></td>
<td></td>
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<td>48 hour</td>
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<tr>
<td>8</td>
<td>Loss of electric service</td>
<td>≥ 50,000 for 1 hour or more</td>
<td>EIA – Sch-1 EIA – Sch-2</td>
<td>1 hour</td>
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<td></td>
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<td></td>
<td></td>
<td>48 hour</td>
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<tr>
<td>9</td>
<td>Complete operation failure of electrical system</td>
<td>If isolated or interconnected electrical systems suffer total electrical system collapse</td>
<td>EIA – Sch-1 EIA – Sch-2</td>
<td>1 hour</td>
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<td></td>
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<td>48 hour</td>
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</table>

All DOE EIA-417 Schedule 1 reports are to be filed within 60-minutes after the start of an incident or disturbance.

All DOE EIA-417 Schedule 2 reports are to be filed within 48-hours after the start of an incident or disturbance.

All entity required to file a DOE EIA-417 report (Schedule 1 & 2) shall send a copy of these reports to NERC simultaneously, but no later than 24 hours after the start of the incident or disturbance.

### Additional Information

- **Incident No.**
- **Incident**
- **Threshold**
- **Report Required**
- **Time**

All NERC Preliminary Disturbance reports will be filed within 24 hours after the start of the incident.

If an entity must file a DOE EIA-417 report on an incident, which requires a NERC Preliminary report, the Entity may use the DOE EIA-417 form for both DOE and NERC reports.

*Any entity reporting a DOE or NERC incident or disturbance has the responsibility to also notify its Regional Council.*
Appendix 7A — Regional and Interregional Telecommunications

Appendix Subsections
A. NERC Hotline
B. NERCnet

Attachment 1 – NERCnet User Application Procedure and NERCnet User Application Form
Attachment 2 – NERCnet Security Policy

A. NERC Hotline

This telephone network is intended for emergency or near-emergency situations that involve or affect North American interconnections and when time is a major factor in recognition, prevention, mitigation, or resolution of the emergency. The network consists of a preset conference call that interconnects RELIABILITY COORDINATOR centers. The communication between Regions is actuated by calling the preset conference telephone number. This sets up the conference call among the predefined participants.

B. NERCnet

Description

NERCnet is a network intended to provide an interregional data exchange infrastructure for entities subject to requirements under the Operating Policies as defined by the NERC Operating Manual. The network is designed to support multiple applications, addressing a variety of data exchange requirements, such as the Interregional Security Network, Interchange Distribution Calculator, Reliability Coordinator Information System, and others. All applications that expect to use NERCnet must follow the NERCnet User Application Procedure. (Refer to Attachment 1 of Appendix 7A).

All clients of NERCnet must agree to the NERCnet Security Agreement as signed by the President of NERC and an officer of the client’s organization. (Refer to Attachment 2 of Appendix 7A.)

The NERC Telecommunications Manager is responsible for monitoring network activity and for reviewing, for verifying billing and usage statistics provided by the frame relay vendor.
**Interregional Security Network**

The Interregional Security Network (ISN) is a near-real-time data exchange application for the purpose of sharing operational security information. The data exchange requirements are explained in Policy 4B (System Coordination – Operational Security Information). The ISN is an Inter-Control Center Communications Protocol (ICCP) based application for exchanging operational security data over NERCnet.

ISN nodes reside primarily at RELIABILITY COORDINATOR sites. Each CONTROL AREA will be responsible for supplying their data to an ISN node for retrieval by any authorized participant. CONTROL AREAS will supply data to and retrieve data from the ISN nodes.

Each ISN node shall be responsible for acquiring, installing, and maintaining the ICCP node hardware and database to support the ISN data requirements. All ISN nodes will support the use of the OSI data transport protocol for ISN node to ISN node communications.
Attachment 1 – NERCnet User Application Procedure

Implementation and Responsibilities
NERC will be the authorizing entity for any applications added to NERCnet. NERC will advise the Data Exchange Working Group (DEWG) and Telecommunications Working Group (TWG) of any new applications.

Procedures
This procedure will apply to all requests to add new applications and related network requirements to NERCnet.

1. The User or Sponsoring Group must submit a completed NERCnet User Application Form to the NERC Telecommunications Manager (see the form below).

2. If the User or Sponsoring Group has not already completed the NERCnet Security Agreement, the User or Sponsoring Group will request a copy of the agreement and complete and return it as appropriate.

3. The NERC Telecommunications Manager will review the form and determine if the form requires clarification, additional information, or must be resubmitted. Upon approval of the form the NERC Telecommunications Manager will forward the form to the NERC Operating Reliability Subcommittee (ORS).

4. ORS will review the request to determine whether the new application is an appropriate use for NERCnet facilities.

5. If the ORS approves the application, the form will be signed by the ORS chair and returned to NERC Telecommunications Manager.

6. The NERC Telecommunications Manager will notify the requesting User or Sponsoring Group of the approval or denial of the request.

7. The NERC Telecommunications Manager will forward the application form to the NERC DEWG and TWG chairmen for review:

   - The DEWG will review the form and supply the data requirements, i.e., Data latency, bandwidth requirements, etc., then forward the form to the TWG.

   - The TWG will then review the completed form and accompanying documentation to determine the design criteria required for the specific application. This would include such items as routers, local loop issues, management, and security requirements.

8. “The NERC Telecommunications Manager will contact the communication vendor to determine the cost, and provide the cost estimate to the NERC User or Sponsoring Group for cost allocation purposes and final authorization to proceed with design implementation. The NERC Telecommunications Manager will also provide a project schedule for network implementation.”

9. The NERC Telecommunications Manager will oversee the daily activities related to network implementation for the approved application and report progress to the TWG as required.”
### NERCnet User Application Form

#### Section A – Contact Information
1. Submitter
2. Contact name
3. Mailing Address
4. Telephone
5. Fax
6. e-mail address

#### Section B – Application Information
7. Network Connections needed by (date – M/d/yyyy)
8. Application active by (date – M/d/yyyy)
9. Protocol(s) required
10. Bandwidth – Normal | Peak

#### Section C – Application/Network Security Application
11. Data Confidentiality Agreement signed? | Yes | No
12. Is application server or client connected to Local Area Network? | Yes | No
13. Is application server or client connected to public Internet? | Yes | No
14. How will non-NERCnet uses access the application server (direct connection, dialup, etc.)
15. Number of users or nodes
16. Testing and implementation
17. Attach brief description of the application.

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**Internal NERC Use**

18. Response requirement
19. Priority assigned
20. If application uses TCP/IP are IP addresses to be assigned by network administrator?
21. Date received by NERC
22. Date forwarded to NERC Operating Reliability Subcommittee

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Version 2 | A7A-4 | Approved by Board of Trustees: October 8, 2002
Definitions

Section A – Contact Information

1. Enter the identity of the entity making the request (e.g., NERC OASIS Standards Collaborative)
2. Enter the name of the person who will be the point of contact for this request.
3. Enter the postal address of the contact person
4. Enter the telephone number for the contact person.
5. Enter the fax number for the contact person.
6. Enter the e-mail address for the contact person.

Section B – Application Information

7. Enter the date when connections to NERCnet are needed. This should reflect the date the connection is needed for testing.
8. Enter the date this application is scheduled to be active, in a production environment.
9. Enter the protocol needed for this application (i.e., TCP/IP, OSI)
10. Enter projected data bandwidth requirements for this application for both normal and peak traffic loads.

Section C – Application and Network Security Information

11. If the applicant has not already signed the NERCnet Security Agreement, a copy should be requested from the NERC Telecommunications Manager, signed, and returned with this application.
12. Indicate whether the server for this application is connected to a Local Area Network.
13. Indicate whether the server for this application is connected (directly or indirectly) to the public Internet.

If yes to either question 12 or 13, please attach a description of any firewall(s) (i.e., router with filters, hardware firewall, etc.) including a general description of the “access rules” enforced by the firewall. Also, please provide a diagram of your internal network showing the protection between the Internet or a Local Area Network and the proposed connection to NERCnet. For security reasons, network and firewall configurations should be supplied in hardcopy only via U.S. Mail. All network and firewall configuration data will be considered confidential. Access to these documents will be on a need to know basis only.

14. Identify how non-NERCnet users of this application will access the application.
15. Identify the intended users of this application (i.e., NERC RELIABILITY COORDINATORS, OASIS Customers, etc.).
16. Identify any special circumstances required for testing, such as a connection to the application vendor or for implementation. Attach a brief description as appropriate.
17. Attach a brief description of the application. The description should elaborate on items such as any special connection requirements or data exchange requirements. If available, provide a copy of any User’s Manual and any procedures documenting node outage notification guidelines for the application.
Attachment 2 – NERCnet Security Policy

Policy Statement
The purpose of this NERCnet Security Policy is to establish responsibilities and minimum requirements for the protection of information assets, computer systems and facilities of NERC and other users of the NERC frame relay network known as “NERCnet.” The goal of this policy is to prevent misuse and loss of assets.

For the purpose of this document, information assets shall be defined as processed or unprocessed data using the NERCnet Telecommunications Facilities including network documentation. This policy shall also apply as appropriate to employees and agents of other corporations or organizations that may be directly or indirectly granted access to information associated with NERCnet.

The objectives of the NERCnet Security Policy are:

- To ensure that NERCnet information assets are adequately protected on a cost-effective basis and to a level that allows NERC to fulfill its mission.
- Establish connectivity guidelines to establish a minimum level of security for the network.
- To provide a mandate to all Users of NERCnet to properly handle and protect the information that they have access to in order for NERC to be able to properly conduct its business and provide services to its customers.

NERC’s Security Mission Statement
NERC recognizes its dependency on data, information, and the computer systems used to facilitate effective operation of its business and fulfillment of its mission. NERC also recognizes the value of the information maintained and provided to its members and others authorized to have access to NERCnet. It is, therefore, essential that this data, information, and computer systems, and the manual and technical infrastructure that supports it, is secure from destruction, corruption, unauthorized access, and accidental or deliberate breach of confidentiality.

Implementation and Responsibilities
This section identifies the various roles and responsibilities related to the protection of NERCnet resources.

NERCnet User Organizations
Users of NERCnet who have received authorization from NERC to access the NERC network are considered users of NERCnet resources. To be granted access, users must complete a User Application Form and submit this form to the NERC Telecommunications Manager.

It is the responsibility of NERCnet User Organizations to:

- Use NERCnet facilities for NERC authorized business purposes only.
- Comply with the NERCnet Security policies, standards and guidelines as well as any procedures specified by the data owner.
- Prevent unauthorized disclosure of the data.
- Report security exposures, misuse or non-compliance situations via SCIS or the NERC Telecommunications Manager.
- Protect the confidentiality of all user IDs and passwords.
Appendix 7A — Regional and Interregional Telecommunications

- Maintain the data they own.
- Maintain documentation identifying the users who are granted access to NERCnet data or applications.
- Authorize users within their organizations to access NERCnet data and applications.
- Advise staff on NERCnet Security Policy.
- Ensure that all NERCnet users understand their obligation to protect these assets.
- Conduct self-assessments for compliance.

User Accountability and Compliance
All users of NERCnet are required to become familiar with and ensure compliance with the policies in this document.

Violations of the NERCnet Security Policy may include, but not be limited to any act that:

- Exposes NERC or any user of NERCnet to actual or potential monetary loss through the compromise of data security or damage.
- Involves the disclosure of trade secrets, intellectual property, confidential information or the unauthorized use of data.
- Involves the use of data for illicit purposes, which may include violation of any law, regulation or reporting requirement of any law enforcement or government body.
NERCnet Security Agreement

Parties
This Agreement is between the NERCnet (North American Electric Reliability Council’s network) Client (“Client”) and the North American Electric Reliability Council (“NERC”).

Purpose
This Agreement is to help ensure the physical and logical security of the NERCnet telecommunications system and its applications and to ensure the proper performance of the applications that will rely on NERCnet for data receipt and delivery.

Premise
1. NERC has established a telecommunications system (NERCnet) to enable the exchange of operating information among operating authorities. The operating information is critical to ensure the operating security of the Interconnections within NERC.

2. The Client desires to establish and maintain a connection to the NERCnet telecommunications system for the purpose of exchanging operating information with other NERCnet clients.

3. The Client understands that the integrity of the operating information and the NERCnet system are critical to ensure the operating security of the Interconnections within NERC.

Agreements
THEREFORE the parties agree as follows:

1. NERC authorizes connection of the Client to the NERCnet telecommunications system.

2. The Client will submit its Telecommunications requirements, including data destinations and transmission rates and volume, to NERC for approval and network connection design.

3. The Client will maintain its connection to NERCnet in accordance with the policies and procedures established and modified from time to time by NERC, including any supplemental procedures established by the Client. In the event of a conflict between the Client and NERC procedures, NERC procedures will prevail.

4. The Client will take no action on the NERCnet that will in any way cause data supplied by other clients to be modified. The Client will ensure that its installation will be designed and operated in a manner that will not compromise the operation of NERCnet.

5. The Client will take no action that will in any way impair the operability of the NERCnet system itself.

6. The Client will use NERCnet only for those purposes authorized by NERC.

7. The Client will allow NERC to periodically review the Client’s connection interface. All connections (physical, logical, or virtual) to the NERCnet Interface to the Wide-Area Network will be assessed, analyzed, and periodically reviewed by NERC, to ensure proper network utilization and design.

8. NERC will not knowingly compromise the firewall of the client.

9. Any Client’s NERCnet connection that is judged by NERC to have a negative impact on the security or performance of other Clients’ applications will be changed to immediately remedy this
negative impact. This may include modification of the Client's physical, logical, or virtual connection or reduction or increase of the Client's transmission rates or volume, as required. At the Client’s request NERC may propose a modified design that would support the Client’s connectivity needs.

10. The Client will reimburse NERC for all costs associated with the Client’s NERCnet connection according to the cost allocation algorithm established for all NERCnet Clients.

**Non-compliance**

A NERCnet Client found not to be in compliance with this Agreement may be prohibited from continuing its connection to NERCnet. This prohibition may remain in effect until NERC determines that the NERCnet Client has resumed compliance with this Agreement.

**Terms and Terminations**

This Agreement shall commence immediately upon the signatures of an officer of the NERCnet Client’s organization and the President of NERC, and shall remain in effect until terminated by either party. Any NERCnet Client wishing to terminate this Agreement shall notify the President of NERC in writing of its desire to terminate this Agreement. Terminations shall be effective 30 days following acknowledgment of receipt of such written notice. Termination does not excuse the NERCnet Client from holding confidential any Operational Data obtained before the period has passed. Upon termination, the NERCnet Client will be prohibited from access to the NERCnet facilities. The Client shall be responsible for all costs associated with the termination and removal of its NERCnet connection.

**Governmental Authorities And Other Agencies**

This Agreement is subject to the laws, rules, regulations, orders and other requirements, now or hereafter in effect, of all regulatory authorities having jurisdiction over the NERCnet Client. All laws, ordinances, rules, regulations, orders and other requirements, now or hereafter in effect, of governmental authorities that are required to be incorporated in agreements of this character are by this reference incorporated in this Agreement.

**General**

This Agreement constitutes the entire and only agreement between the Client and NERC and all other prior negotiations, representations, agreements, and understandings are superseded hereby. No agreements altering or supplementing the terms hereof may be made except by means of a written document signed by the duly authorized representatives of the parties.

For NERCnet Client

Signature of Officer

Date

For NERC

Signature of President

Date
Appendix 8B1 — Suggested Items for System Operator Training Courses

Appendix Subsections

A. Prerequisite Fundamental Knowledge
B. Policy 1A: Generation Control and Performance
C. Policy 1B: Automatic Generation Control
D. Policy 1C: Frequency Response and Bias
E. Policy 1D: Time Control
F. Policy 1E: Performance Standard
G. Policy 1F: Inadvertent Interchange
H. Policy 2A: Transmission Operations
I. Policy 2B: Voltage and Reactive Control
J. Policy 3: Interchange
K. Policy 4A: Monitoring System Conditions
L. Policy 4B: Coordination with Other Systems – Normal Operations
M. Policy 4C: Maintenance Coordination
N. Policy 4D: System Protection Coordination
O. Policy 5A: Coordination with Other Systems
P. Policies 5B and 5C: Insufficient Generating Capacity and Transmission System Relief
Q. Policy 5D: Separation from the Interconnection
R. Policy 5E: System Restoration
S. Policies 5F and 5G: Disturbance Reporting and Sabotage Reporting
V. Policy 6C: Operations Planning – Automatic Load Shedding
W. Policy 6D: Operations Planning – System Restoration
X. Policy 7: Telecommunications
Y. Policy 8: Operator Personnel and Training

The following outline includes suggested items for inclusion in a training program. This outline is intended to be a comprehensive listing to be utilized by interconnected systems in designing training courses to meet the specific needs of system operating personnel. Actual course content for any given trainee will depend upon the trainee’s background, job responsibilities, organizational requirements, its existing program, and its training objectives, among others.
A. Prerequisite Fundamental Knowledge

1) Concepts of DC and AC voltage and current
2) DC and AC power calculations
3) Three-phase AC power systems
4) Peak and RMS voltage relationship
5) Line-to-ground and line-to-line voltages in an AC system
6) Relationships between power, voltage, current, and impedance in an AC and in a DC system
7) Concept of active, reactive, and complex AC power and the vector relationship between the components of power
8) Concept of AC impedance and the vector relationship between the components of impedance
   ♦ Resistance
   ♦ Inductive reactance
   ♦ Capacitive reactance
9) Impact on total impedance of connecting impedance in series and in parallel
10) Concept of phase angle
11) Concept of power angle
12) Concept of power factor
13) Fundamentals of generator operation
   ♦ Basic theory of operation
   ♦ Concept of torque angle
   ♦ Generators as the source of frequency
   ♦ Governor control systems
      ♦ Droop and deadband
   ♦ Excitation control systems
      ♦ Voltage regulators
   ♦ Combustion control systems
      ♦ Advantages and disadvantages of different types of units
14) Fundamental theory and operation of key power system equipment
   ♦ Power transformers
      ♦ Tap changers
      ♦ Transformer connections
         ♦ Wye
         ♦ Delta
   ♦ Instrument transformers
      ♦ CTs
      ♦ PTs
   ♦ Transmission lines
      ♦ Conductors and towers
   ♦ Switching devices
      ♦ Circuit switchers
      ♦ Disconnect switches
         ♦ Arc-quenching devices
      ♦ Circuit breakers
         ♦ DC tripping circuits
   ♦ Telecommunication equipment
   ♦ Protective relays
   ♦ Voltage regulators
   ♦ Shunt capacitors and reactors
   ♦ Series capacitors and reactors
Appendix 8B1 – Suggested Items for System Operator Training Courses

- Static VAr compensators
- HVDC system basic concepts
- Meters

15) Purpose and function of NERC and the Regional Councils
16) Purpose and function of the NERC Operating Policies
17) Purpose and function of the Regional Operating Policies
18) Distinction between NERC Policy Criteria, Requirements, Guides, and Standards
B. Policy 1A: Generation Control and Performance

**Fundamental Knowledge**

1) Energy balance concept
2) Concept of stored energy
   ♦ Including the energy stored in the rotating mass (inertial) and the energy stored in the electric and magnetic fields of the power system
3) Load/frequency relationship
   ♦ 1% change in frequency leads to approximately a 1% change in the total load magnitude
4) Need for operating reserves
5) Automatic usage of operating reserves following system disturbances
6) Governor control process in a generating unit
7) Concept of an Interconnection and its relationship to frequency
8) Concept of the division of the Interconnection into control areas
9) Concept of operating the power system to withstand the single most severe contingency

**Terms**

1) Interconnection
2) Operating reserve
3) Contingency reserve
4) Spinning reserve
5) Non-spinning reserve
6) Regulating reserve
7) Reserve sharing group
8) Load forecasting
9) Forced outage
10) Load diversity
11) Regional Council
12) Subregion
13) Interruptible load
14) Disturbance control standard (DCS)
15) Contingency
16) Most severe single contingency
17) Control area
18) Area control error (ACE)
19) Automatic generation control (AGC)
20) Jointly owned generation
21) Dynamic schedules
22) Pseudo-ties
23) Disturbance condition (as defined in the DCS)

**Concepts**

1) Maintain acceptable levels of operating reserve to withstand probable contingencies
2) Automatic use of operating reserves following contingencies
3) Relation between governor control systems and spinning reserve
   ♦ Not all spinning reserve is governor responsive
4) Impact of governor settings on a generator’s MW response to a disturbance
   ♦ Droop, deadband, etc.
5) Monitor generating plant status to ensure correct generation levels and reserve margins
6) Monitoring the 10-minute recovery of ACE after a disturbance condition in order to conform to the DCS
7) Reestablishing operating reserve levels following the use of operating reserves

8) Understanding the purpose and application of dynamic schedules
   ♦ As pertaining to load and/or generation

**NERC Standards and Guidelines**

1) Relation between NERC, Regional, Subregional, etc. operating policies and procedures

2) Rules for maintaining adequate levels of operating reserves

3) Rules for the division of operating reserve into its components
   ♦ Spinning, non-spinning, contingency, regulating, etc.
   ♦ Typically 50% of operating reserve is spinning

4) Rules for the use of interruptible load as a component of operating reserve

5) Rules for the use of a reserve sharing group to fulfill operating reserve requirements
   ♦ Purpose and function of the disturbance control standard (DCS) (Addressed in detail in Policy 1E)

6) Rules for the division of a generator’s spinning reserve when the unit is jointly owned

7) Adjustment of contingency reserve following failure to comply with the DCS
C. Policy 1B: Automatic Generation Control

**Fundamental Knowledge**

1) Theory and operation of an AGC system  
2) Understanding of the components of the ACE equation  
3) Working knowledge of the theoretical response of tie-line bias control to an internal and external control area generation disturbance  
   - For an external disturbance, a control area will not develop an ACE, if its bias is exact  
4) Need for regulating reserve and its description as a subset of spinning reserve  
5) Need for a manual assist to the AGC process  
6) Possible impacts of HVDC flows on the energy balance and frequency control process  

**Terms**

1) Interchange  
2) Actual net interchange  
3) Scheduled net interchange  
4) Inadvertent interchange  
5) Actual frequency  
6) Scheduled frequency  
7) Metering error  
8) Frequency bias  
9) ACE equation  
   - \[ ACE = (NIA - NIS) - 10\beta (FA - FS) - IME. \]  
   - For the ERCOT Interconnection:  
     \[ ACE = (NIA - NIS) + 10\beta (FA - FS) \]  
     (Note ERCOT uses a “+10\beta” term)  
1) Frequency regulation  
2) Control performance standards (CPS)  
3) Overlap regulation service  
4) Supplemental regulation service  
5) HVDC system  
6) Governor control system  
7) Security limits  
8) Generator AGC control status  
   - On or off regulation  
9) Generator AGC response mode  
   - Baseload, emergency assist, etc.  
10) Generator load limiters  
   - To intentionally restrict a unit’s response  
11) Response rate  

**Concepts**

1) Concept of the metered boundaries of a control area  
2) Recognize the two primary duties of a control area  
   - Minimize interchange error  
   - Assist with the Interconnection’s frequency regulation  
3) How net interchange error and/or frequency error drives the ACE magnitude and the control area’s generation response
Appendix 8B1 – Suggested Items for System Operator Training Courses

4) How to assume manual control of a control area’s generation following the loss or misoperation of the AGC system
5) How to suspend AGC when control actions are adverse to system security
6) Identifying and monitoring the units that are responsive to AGC commands
7) Importance of distributing AGC control among as many units as possible
8) Consequences of inadequate generation under AGC control
9) How joint control units are utilized in the AGC process
10) Monitoring the performance of the generator’s governor control system to ensure adequate and timely response
11) Monitoring the performance of the control area’s AGC system to ensure ACE is accurate and within reasonable bounds
12) The application of CPS1 and CPS2 standards
   ♦ Maintaining ACE within the bounds defined by the CPS
13) Understanding the impact of dynamic schedules on the AGC process
14) Why to adjust and how to adjust a generator’s AGC control status
   ♦ On or off control
15) When to change and how to adjust a generator’s AGC control mode
   ♦ Baseload, emergency assist, etc. (Many different names given to these modes of control)

NERC Standards and Guidelines

1) Difference between overlap and supplemental regulation service
2) Suspending AGC if frequency deviation exceeds ±0.2 Hz
3) Purpose of the control performance standards
   ♦ CPS1 and CPS2
   ♦ See the Performance Standard Training document in the NERC Operating Manual for details on the CPS and DCS
4) Typical data scan rates (minimum of 4 seconds) for an AGC system
D. Policy 1C: Frequency Response and Bias

Fundamental Knowledge

1) Meaning of a % droop (governor setting)
2) Meaning of a governor deadband
3) Purpose of the three common AGC control modes and the circumstances under which each might be used
4) Components of frequency bias including governor response and the load/frequency relationship
5) Relation between frequency bias and a system’s natural response (frequency response characteristic-FRC)
   ♦ FRC changes with changing system conditions
   ♦ The two may be intentionally different

Terms

1) Frequency response characteristic (FRC)
2) Frequency bias setting
   ♦ Fixed bias setting
   ♦ Variable bias setting
3) AGC control modes
   ♦ Constant frequency control
   ♦ Constant interchange control
   ♦ Tie-line bias control
4) Governor droop
5) Governor deadband
6) Valve position limits
   ♦ For steam control valves, etc.

Concepts

1) Operate the control area’s AGC equipment as required to maintain adequate generation control
   ♦ Every control area’s equipment is somewhat different
2) Monitor AGC performance and, when necessary, change AGC control modes
3) Impact of various AGC control modes on the generation control process
   ♦ Constant frequency ignores interchange error
   ♦ Constant interchange ignores frequency error
4) Importance of maintaining AGC in the tie-line bias control mode
   ♦ When to use other AGC control modes
5) Methods and reasons for proportioning the bias setting of those jointly owned units that use dynamic schedules or pseudo-ties
   ♦ For those jointly owned units that use fixed schedules, the host control area for the jointly owned unit counts all of the unit’s governor response in its frequency bias
6) Impact of the provision of supplemental and/or overlap regulation on all involved control areas’ frequency bias settings

NERC Standards and Guidelines

1) Methods for determining a control area’s frequency bias
2) Review frequency bias setting and report it to NERC at least once a year
3) Rules for the minimum values of frequency bias settings (see Policy 1C)
   ♦ 1% of peak load or
   ♦ 1% of maximum generation level
4) Rules for the installation of governor control systems
- Most units over 10 MW
5) Governors should provide a 5% droop
6) Governor deadband setting no greater than ±0.036 Hz
E. Policy 1D: Time Control

**Fundamental Knowledge**

1) Relationship between accumulated frequency error and time error
2) Concept of time error control
   ♦ Intentional errors to eliminate past unintentional errors

**Terms**

1) Scheduled frequency
2) Accumulated time error
3) Time error correction
4) Interconnection (time error) monitor
5) Regional (time error) monitor
6) Time correction offset
   ♦ Frequency or schedule offset
7) Automatic time error correction

**Concepts**

1) Understanding of process in which Interconnection time error monitor determines accumulated time error by comparing time signal based on system frequency to a time signal received from the National Bureau of Standards
2) Understanding of process in which the Interconnection time error monitor initiates time error corrections, working through any Regional time error monitors in the Interconnection
3) Respond when asked to perform time error corrections
   ♦ Eliminate accumulated time error by intentionally creating time error in the opposite direction
4) Adjust accumulated time error (if desired) prior to restoring ties to the Interconnection
   ♦ Either correct time error before restoring ties or adjust accumulated time error to the same value as the larger system after ties are restored
5) Understand the consequences of a control area not participating in a time error correction
   ♦ Inadvertent accumulation
   ♦ Diminishes time error correction effect

**NERC Standards and Guidelines**

1) Time error limits are established for Interconnection reliability
   ♦ Time error limits are not intended solely to correct time error
2) Time error corrections should start and end on the hour or half hour
3) Offsets for time error correction:
   ♦ Frequency offset is ±0.02 Hz
   ♦ Schedule offset is 20% of the frequency bias setting
4) Interconnection time error monitors shall periodically issue an actual time error notification (accurate to within 0.1 second) to all Regional time error monitors
5) Regional time error monitors shall issue an hourly accumulated time error notification accurate to within 0.1 second
6) Acceptable accumulated time error limits for the different Interconnections are listed in Appendix 1D
F. Policy 1E: Performance Standard

**Fundamental Knowledge**

1) The purpose of and theory behind the new CPS
   - A new NERC Tutorial on the CPS is now available from NERC
2) New CPS is a technically defensible standard
   - Old control performance criteria were based on operating experience and not technically justified
   - Major weakness in old criteria was their failure to recognize the impact of ACE on the Interconnection’s frequency
3) CPS1 standard encourages control areas to keep their ACE small and in such a direction that it helps eliminate Interconnection frequency errors
4) CPS2 standard sets a limit on the magnitude of ACE in order to discourage excessive tie-line flows

**Terms**

1) Disturbance Control Standard (DCS)
   - Time limits for recovering from a disturbance condition
   - Disturbance condition is defined in the DCS standard
2) Control Performance Standard 1 (CPS1)
   - Statistical measure of a control area’s ACE variability
   - CPS1=(2-Compliance Factor) x 100%
   - Compliance Factor = \( \frac{\text{Control Parameter}_{12-Month}}{\varepsilon_{1}} \)
   - Control Parameter = \( \frac{\text{ACE}_{\text{Minute}}}{-10B_{\text{Minute}}} \times \Delta F_{\text{Minute}} \)
3) Control Performance Standard 2 (CPS2)
   - Sets bounds on the magnitude of a control area’s ACE
   - Bounds stated as \( \pm L_{10} \)
   - \( L_{10} = 1.65 \times \varepsilon_{10} \sqrt{(-10B_{1})(-10B_{2})} \)
4) Epsilon (\( \varepsilon \))
   - Epsilon is the acceptable frequency error
   - Both 1 minute and 10 minute averages of epsilon are used in the CPS1 and CPS2

**Concepts**

1) Monitor ACE in combination with the Interconnection’s frequency error to ensure compliance to the CPS1 standard
2) Monitor the magnitude of ACE to ensure it stays within the \( \pm L_{10} \) bounds to ensure compliance with the CPS2 standard
3) Following a system disturbance, restore ACE to zero or its pre-disturbance value within 10 minutes to ensure compliance with the DCS standard

**NERC Standards and Guidelines**

1) The Disturbance Control Standard (DCS) sets a 15-minute time limit on the restoration of a control area’s ACE following a disturbance condition
2) Compliance with the CPS requires 100% compliance with CPS1 and 90% compliance with CPS2
3) Compliance with the DCS requires meeting the DCS 100% of the time
4) Each control area shall continually compute (for each one-minute period) their control parameters
5) Control parameters are used to compute the control area’s compliance factor
6) Compliance factors are used to determine the control area’s CPS1 conformance percentage
7) Control areas must report their compliance level to the CPS on a monthly basis
   ♦ Data survey called Performance Standard Surveys
8) DCS compliance data is reported quarterly
   ♦ Data survey called Disturbance Control Standard Surveys
Appendix 8B1 – Suggested Items for System Operator Training Courses

G. Policy 1F: Inadvertent Interchange

Fundamental Knowledge

1) Causes of inadvertent
   ♦ Inadvertent is sometimes desirable
2) Primary or unintentional inadvertent main causes are metering and scheduling errors and AGC lag
3) Secondary or intentional inadvertent main cause is governor response

Terms

1) Inadvertent interchange
   ♦ Primary or unintentional inadvertent
   ♦ Secondary or intentional inadvertent
2) Accumulated inadvertent
   ♦ On-peak conditions
   ♦ Off-peak conditions
3) Inadvertent payback
   ♦ Bilateral payback
   ♦ Unilateral payback
   ♦ Payback “in-kind”
4) Tie-line metering
5) Metering errors

Concepts

1) AGC tie-line metering must be continually checked to identify metering errors
   ♦ Metering errors will lead to inadvertent accumulations
2) Verify scheduled interchange totals as needed
3) Monitor the magnitude of the ACE value and adjust generation as needed to keep ACE small and minimize inadvertent accumulations
4) Track on-peak and off-peak inadvertent interchange accumulations and perform inadvertent payback as required
5) Continually verify the accuracy of AGC tie-line metering by comparing the control area’s hourly MWh meter readings with integrated AGC tie-line meter totals
6) Adjust AGC equipment “compensation” setting to account for known metering errors
   ♦ Consult with all impacted control areas prior to making any adjustments
7) Recognize the difference between primary and secondary inadvertent
   ♦ Metering error is a major source of primary inadvertent
   ♦ Governor response is a major source of secondary inadvertent

NERC Standards and Guidelines

1) Each control area shall submit a monthly summary of their inadvertent interchange accumulations to NERC
H. Policy 2A: Transmission Operations

**Fundamental Knowledge**

1) Equipment ratings can be due to thermal limits, angle stability limits, voltage limits, etc.
   - Thermal limits are due to current flow
     - The current flow delivers the MVA at the operating voltage
   - Angle stability limits are either transient or oscillatory stability limits
     - All types of angle stability limits are imposed to prevent the loss of the “magnetic bond” that holds the system together
   - Voltage limits may be to prevent a localized low voltage problem or to prevent an area wide low voltage problem (voltage collapse)

2) Meaning of the term “condition”
   - Normal condition
   - Abnormal condition
   - Emergency condition

**Terms**

1) Transmission security
   - Differentiate between transmission security and transmission reliability
2) Reliability Coordinators
3) Operating security limits
   - Thermal
   - Angle stability
   - Voltage magnitude and/or voltage stability
4) Equipment ratings
   - Typically thermal but may be voltage related
5) Load shedding
   - To prevent low voltage and/or low frequency
6) Planned outages
7) Forced outages
8) Host control area
   - As used here, indicates control area in which a facility is physically located
9) Transmission interface
   - Recognized interface point between sending and receiving areas
10) Transmission service requests
11) Transmission switching
12) Protective relay targets
13) Oscillograph
14) Restoration
15) Voltage stability
16) Voltage collapse

**Concepts**

1) Responsibilities of any designated Reliability Coordinators
2) Monitor transmission system elements to ensure equipment ratings are not exceeded
3) Coordinate forced and planned outages with all impacted systems
   - Perform switching as required to ensure safety and security
   - Coordinate switching with all impacted parties
4) Respond to operating limit violations in order to relieve the facility overload
5) When appropriate, initiate manual load shedding to relieve an abnormal condition
6) Analyze a request for transmission service and respond as required to ensure transmission system security
7) Recognize the conditions that indicate an impending voltage collapse and respond as required
8) Recognize the conditions that may indicate a pending system separation and respond as required
9) Evaluate a request for a transmission line outage
   ♦ For a simple system, predict power flow on one of several paths once a specified path is taken out of service
10) Purpose and function of protective relays (Addressed in detail in Policy 4)

**NERC Standards and Guidelines**

1) Every Region, Subregion, or interregional security group shall establish one or more Reliability Coordinators to continually assess transmission system security and coordinate emergency operations among its control areas
2) Planned transmission system outages shall be coordinated with all systems affected
I. Policy 2B: Voltage and Reactive Control

**Fundamental Knowledge**

1. Relation between reactive power flow and voltage
2. Voltage square relationship to a shunt capacitor’s MVAr production and a shunt reactor’s MVAr absorption
3. Natural capacitance of a high voltage transmission line
4. Concept of Ferranti voltage rise and Ferranti voltage rise relationship to line length and source bus strength
5. Theory of voltage stability and voltage collapse
   - In a voltage stable system, power flow and voltage levels are controllable. Opposite is true in a voltage unstable system
   - Voltage instability may lead to a voltage collapse
   - When a voltage collapse occurs, an area-wide reactive power deficiency leads to a collapse of system voltage
6. Importance of maintaining adequate reactive reserve
7. Difference between dynamic reactive reserve and static reactive reserve
   - Manually switched shunt capacitors are static reactive reserve
   - Generators, synchronous condensers, SVCs, are dynamic reactive reserve
8. Use of generator reactive capability curves
9. Use of the terms “leading” and “lagging”
10. Understand the concept of transmission line charging and its relation to voltage control
11. Theory and application of power system stabilizers (PSS)
   - PSS is an electronic device installed in a generator’s excitation system
   - Purpose of PSS is to help dampen low frequency power oscillations

**Terms**

1. Generator reactive capability
   - Lagging/overexcited
   - Leading/underexcited
2. Static VAr compensator
3. Synchronous condenser
4. Transmission line charging
5. Voltage regulator
6. Power system stabilizers
   - Dampen oscillations
7. Ferranti voltage rise
8. Reactive dispatch
9. Reactive reserves
   - Dynamic
   - Static

**Concepts**

1. Relationship between reactive power flow and system voltage levels
2. Monitor transmission system voltage levels to ensure voltages stay within acceptable bounds
   - Actual, scheduled, and nominal voltage levels
3. Monitor and control reactive power flows to ensure transmission security and acceptable voltage levels
   - Ensure that the reactive power flows on tie-lines are within allowable ranges
   - Note unusual reactive power flows that may indicate unstable system voltages and/or voltage collapse
4. Recognize the voltage squared ($V^2$) impact on capacitive and inductive (reactor) resources
Appendix 8B1 – Suggested Items for System Operator Training Courses

- Basis for “getting ahead of the voltage”

5) Operate reactive equipment to maintain adequate voltages
   - Reactive equipment includes shunt capacitors, shunt reactors, transformers, generators, SVCs
   - HVDC systems and series capacitors may also be used to control reactive power flow

6) Monitor reactive reserve levels to ensure adequate amounts available to withstand probable contingencies
   - Difference between dynamic and static reactive reserves
   - Location of reactive reserves are critical as it is difficult to transmit reactive power long distances
   - Restore adequate reactive reserve levels following the use of reactive reserves

7) Monitor generator excitation systems to ensure adequate field excitation
   - Ensure voltage regulators are in automatic mode of operation if at all possible

8) Procedures for removing transmission lines as a voltage control tool

9) Purpose of power system stabilizers (PSS) and possible consequences if PSS are out-of-service

10) Reasons for testing the reactive capability of dynamic reactive resources
    - Ensure reactive power is rapidly available when it is needed
    - “Nameplate” reactive power of a generator is often quite different than available reactive power of a generator

**NERC Standards and Guidelines**

1) Maintain adequate levels of reactive power reserves
2) Test reactive capability of dynamic reactive resources
3) Maintain adequate field excitation when a unit is on manual voltage regulation
J. Policy 3: Interchange

Fundamental Knowledge
1) Concept of interconnected operations services (IOS) or ancillary services
   ♦ IOS or ancillary services are “services” that were formerly bundled with the product (electric energy/capacity) suppliers sold their customers
   ♦ In the new operating environment, the product will be broken down into all of its components
   ♦ Suppliers may sell electric energy/capacity plus a host of services including operating reserves, scheduling services, voltage control, frequency regulation, etc.

Terms
1) Terminology for interchange transactions
   ♦ Interchange, schedule, transaction
   ♦ Arrange, assess, conform, implement
     • Arranging
       * Done by the PSE
     • Assessing
       * Approval or denial
       * Done by the control areas
     • Confirming
       * Done by the control areas
     • Implementing
       * Done by the control areas
       * Incorporate transaction into their AGC interchange schedules

2) Interconnected operations services (IOS)
   ♦ Sometimes called ancillary services
   ♦ Different systems address IOS in different ways

3) Sending control area
4) Receiving control area
5) Intermediary control area
6) Purchasing-selling entity (PSE)
7) Ramp time
8) Ramp duration
9) Curtailment
10) Tagging procedures
11) Interregional security network (ISN)
12) Terminology for stating the transfer capability (See Policy 3E)
   ♦ Total transfer capability (TTC)
   ♦ Available transfer capability (ATC)

Concepts
1) Assess requests for, or changes to, an interchange transaction and approve or deny based on:
   ♦ Available transfer capability
   ♦ Applicable reliability criteria
   ♦ Condition of power system
   ♦ Adequacy of IOS

2) Arrange for the necessary IOS for each interchange transaction as requested and/or required by NERC, Regional, or other reliability entity’s procedures

3) Confirm an interchange transaction by verifying following between sending, receiving, and any intermediary control areas:
   ♦ Magnitude of transaction
Transmission path for transaction (if required)
Start time
End time
Ramp duration
  Note that mismatched ramps will lead to frequency deviations
Responsibilities for operating reserve
Terms for interruption for IOS

4) Implement an interchange transaction by:
  Making required adjustments to the AGC system’s interchange schedules
  Monitoring the ramp rate and duration
  Monitoring transaction start and end times

5) Continually monitor the available transfer capability at recognized interfaces and curtail transmission service as required to ensure transmission security
  Coordinate the interruption of transmission service with all implemented interchange transactions

6) Record all necessary data to ensure a complete record of all interchange transactions and transmission service agreements
K. Policy 4A: Monitoring System Conditions

Fundamental Knowledge

1) Importance of system frequency and its relationship to the system’s overall health
   ♦ Disturbances and frequency deviations
   ♦ Role of inertia
   ♦ Role of governor response
2) Relationship between frequency deviations and voltage phase angle separation
3) Relation between angle stability and voltage phase angle difference
4) Relationship between reactive power flow, voltage magnitudes, and transformer tap adjustments
5) Use of an EMS/SCADA system
6) Methods used to determine power transfer limits
   ♦ Thermal limits
   ♦ Voltage limits
   ♦ Voltage stability limits
   ♦ Angle stability limits
7) Use of an accurate time source (satellite, etc.) to determine a system “standard” time
8) Need to coordinate voltage schedules to minimize reactive power flows and ensure adequate voltage levels
   ♦ Reactive power flow relation to voltage levels and system losses
9) Relationship between voltage levels and angle and voltage stability

Terms

1) Load forecasting
2) Phase angle
   ♦ Power angle
   ♦ Voltage phase angle difference
3) Standard time
4) Voltage schedules

Concepts

1) Measures of system strength
   ♦ Voltage levels
   ♦ Power flow levels
   ♦ Power angle (voltage angle difference)
   ♦ Dynamic reactive reserve margins
2) Utilize available load forecasting tools to predict near term load patterns
3) Identify system separation points following a major disturbance
   ♦ Identify abnormal MW and MVAr flows
   ♦ Identify abnormal voltages
   ♦ Awareness of typical separation points
   ♦ Use of multiple frequency recorders to determine boundaries of islands
4) Monitor available generation as compared to system requirements, respond as required with generation changes
   ♦ Generator ramp rates
   ♦ Generator thermal limitations
   ♦ Generator fuel constraints
   ♦ Generator environmental restrictions
5) Utilize operating knowledge and available tools to continually evaluate system susceptibility to probable contingencies
   ♦ Usage of tools
♦ Knowledge of published operating limits
L. Policy 4B: Operational Security Information

**Fundamental Knowledge**

1) Purpose and operation of the Interregional Security Network (ISN)
2) What is included in “Electric System Security Data” (Appendix 4B)
   - Transmission data such as line loadings
   - Generator data such as unit outputs and ratings
   - Operating reserve data
   - Interchange data
   - ACE and frequency
3) Distinction between normal and emergency conditions

**Terms**

1) Standards of Conduct
   - See Appendix 4B
2) System condition
   - Normal
   - Emergency
3) ISN
4) Electric System Security Data
   - Information used for analyzing the operational security of the Interconnection
5) Reliability Coordinator
   - Any entity responsible for the operational security of one or more control areas

**Concepts**

1) Utilize the ISN to send and receive Electric System Security Data
2) Knowledge of what operating entity is responsible for transmission system security
   - Role of any Reliability Coordinator
3) Actions necessary to conform to the Standards of Conduct
4) Conditions under which Standards of Conduct may be suspended
5) Reasons for suspending Standards of Conduct
6) Communication methods and procedures with other control centers

**NERC Standards and Guidelines**

1) Purpose and content of NERC’s “Confidentiality Agreement for Electric Systems” (Appendix 4B)
Appendix 8B1 – Suggested Items for System Operator Training Courses

M. Policy 4C: Maintenance Coordination

Fundamental Knowledge

1) Applicable switching methods and procedures
2) Applicable outage scheduling procedures
3) Factors that impact active and reactive power flow
   ♦ Generation dispatch
   ♦ Transmission line switching
   ♦ Load location and level
   ♦ Voltage levels
   ♦ Special equipment
     • PST, series capacitors, etc.
4) Purpose and function of voltage control equipment
   ♦ Reactors
   ♦ Capacitors
   ♦ Generators
     • Excitation systems
   ♦ Synchronous condensers

Concepts

1) Factors that must be considered when planning (and implementing) scheduled outages of transmission or generation equipment:
   ♦ System security
   ♦ Personnel safety
   ♦ Transfer capability
2) Consequences on overall system protection when protective relaying systems (or telecommunication systems) are removed for maintenance
3) Knowledge of who must be informed when planning outages of equipment
   ♦ Internal company notifications
   ♦ External notifications (other control centers, etc.)
4) Use of tools that assist with the outage scheduling process
   ♦ Dispatcher power flow
5) Use of generation re-dispatch to adjust system power flows and allow a scheduled outage to proceed
6) Use of transmission switching to adjust system power flows and allow a scheduled outage to proceed
N. Policy 4D: System Protection Coordination

**Fundamental Knowledge**

1) Fundamentals of system protection
   - Purpose of relays and relay schemes
   - Limitations of relays and relay schemes
   - Types of relays used in the transmission system
     - Under/over voltage relays
     - Overcurrent relays
       * Timed
       * Instantaneous
       * Directional
     - Differential relays
       * Bus
       * Transformer
       * Transmission line (fiber optic)
     - Distance relays
     - Pilot protection schemes
       * Directional comparison schemes
       * Telecommunication systems
     - Synchronizing relays
     - Auxiliary relays
       * Lockout relay
       * Tripping relay
     - UFLS
     - UVLS
     - IEEE numbering system (87, etc.)
   - Types of relays used in generating stations
     - Differential
     - Loss of excitation
     - Thermal
     - Negative sequence
     - Volts-per-hertz
     - Underfrequency tripping
   - Concept of zones of protection
   - Coordination of relay schemes
   - Typical protective relay applications
   - Telecommunications requirements for protection systems
   - Purpose and function of special protection systems

**Terms**

1) Special protection systems
2) Protection coordination
3) Automatic reclosing
4) Single-pole tripping
   - Different type of relays (See above)

**Concepts**

1) Knowledge of protective systems
   - Typical protection applications
• Bus protection
• Transformer protection
• Transmission line protection
• Synchronizing systems
• Generator protection
♦ Expected system protective relay response to abnormal conditions

2) Following operation of a tie-line’s protective relays, communicate with other party to determine cause of protective operation
♦ Types of relays used
♦ Interpreting relay targets
♦ Determination of whether a manual reclose should be attempted

3) Knowledge of application of special protection schemes
♦ Transfer tripping schemes
♦ Generator dropping (rejection, runback, etc.) schemes
O. Policy 5A: Coordination with Other Systems

**Fundamental Knowledge**

1) Theory and application of underfrequency load shedding (UFLS) relays
   - All systems have rules for UFLS relay application
   - Basically, shed load to arrest the frequency decline
   - In some systems the relays are programmed first to shed load and then to automatically restore the load if the frequency rises to a set value
     - Problems with automatic load restoration relays during disturbances
   - Uncoordinated UFLS programs can lead to large power swings, large voltage deviations, and cascading outages
2) Theory and application of undervoltage load shedding (UVLS) relays
   - UVLS is a tool for preventing a voltage collapse
   - UVLS used to be uncommon, but there are now many UVLS programs in operation
3) Use of voltage reduction as a load shedding tool
   - In general spinning (motor) type load magnitude is sensitive to frequency deviations while non-spinning (resistive, etc.) type load magnitude is sensitive to voltage deviations. A general rule is that a 5% reduction in customer voltage will lead to about a 3% reduction in load magnitude. (This is only a rule of thumb. Effects of voltage on load will vary.)
   - Reduce the customer’s voltage, not the transmission system voltage

**Terms**

1) Operating emergency
2) UFLS
3) UVLS
4) Emergency assistance

**Concepts**

1) If an emergency condition is anticipated or experienced, communicate key information to surrounding systems
2) If a neighboring system anticipates or is experiencing an emergency condition, make known your available assistance as soon as possible
3) Following the operation of UFLS or UVLS relays, coordinate the restoration of load with neighboring control centers
   - Emphasize the coordination point, systems must not restore without a coordinated plan of operation
4) Given a sustained low frequency condition, utilize manual load shedding to restore frequency
   - May also need to use manual load shedding if deficient in operating reserves
5) Initiate emergency assistance procedures as required
   - Every control area has procedures for sharing emergency assistance with other control areas
   - Emergency assistance may be in the form of capacity, energy, or both capacity and energy
6) Utilize voltage reduction as a load management tool

**NERC Standards and Guidelines**

1) Policy 5A lists several situations that if experienced, should trigger a notification to surrounding systems
P. Policies 5B and 5C: Insufficient Generating Capacity and Transmission System Relief

Fundamental Knowledge
1) When a system suffers a generation loss, the stored energy in the Interconnection immediately supplies replacement energy
   ♦ This causes the Interconnection’s frequency to drop
   ♦ NERC Policy 5B refers to this Interconnection assistance as the Interconnection’s frequency bias
   ♦ Systems must not rely on the Interconnection’s assistance for too long a period as the Interconnection must be ready for the next possible disturbance
   ♦ Procedures for obtaining/delivering emergency assistance
   ♦ Emphasize emergency assistance must be scheduled

Terms
1) Capacity emergency
2) Interconnection’s frequency bias
3) Phase shifter

Concepts
1) Disregard financial aspects when anticipating or experiencing a capacity emergency
2) If unable to achieve a balance between resources and load, manually shed load to restore ACE to an acceptable value
3) Steps to take to avoid and/or eliminate a capacity emergency:
   ♦ Start all available generation
   ♦ Postpone maintenance
   ♦ Purchase capacity and/or energy
   ♦ Call for emergency assistance
   ♦ Shed load
4) Given a major system disturbance, monitor power flows on tie-lines and voltages on key buses to ensure transmission security
   ♦ May need to reduce schedules to relieve tie-line flows
5) When an operating limit violation occurs, steps must be immediately taken to relieve the operating limit violation
6) Load shedding is a powerful tool to use to relieve a stressed system
7) Prior to performing switching to cure an emergency condition, notify any systems that may be impacted by the switching
8) Methods to use to cut schedules
   ♦ For example, an order of progression when cutting schedules

NERC Standards and Guidelines
1) A deficient system shall use the Interconnection’s frequency bias only for the time period needed to:
   ♦ Utilize operating reserve
   ♦ Analyze its ability to recover using its own resources
   ♦ Obtain emergency assistance from other systems
2) If a system is not experiencing a capacity deficiency, unilateral action by that system to restore frequency to normal is forbidden
   ♦ If a system is deficient and is unable to eliminate the deficiency, the system must call for emergency assistance
   ♦ Do not help unless asked
3) Each system operator with transmission security responsibilities shall be given the operating authority required to alleviate operating security limit violations.
Q. Policy 5D: Separation from the Interconnection

**Fundamental Knowledge**

1) Importance of remaining interconnected
   - Dangers inherent when operating as an islanded system
   - The more spinning mass, the more stable the frequency
2) Concept of using generation adjustments to impact system frequency and phase angle to allow resynchronizing
3) Process of synchronizing
   - Matching frequency, voltage magnitude, and voltage phase
   - Use of a synchroscope
   - Operation of synch-check relays
4) Operating limits for generation
   - Across what range of frequency can a generator safely operate?
   - Across what range of voltage can a generator safely operate?

**Terms**

1) Resynchronizing

**Concepts**

1) Methods used to resynchronize two systems
   - Importance of communications between all parties impacted by the resynchronizing
2) Use of load shedding as a tool to allow resynchronizing
   - One system may have a low frequency with no available generation
3) Use of load shedding as a tool to prevent voltage collapse
   - Type of load to shed
     - In general, shed load with a high MVAr usage as this will most help voltage levels
4) During disturbance conditions, monitor generator conditions and initiate generator removal if the units are exposed to unsafe operating conditions
   - If possible, separate generators with local load or with their own auxiliaries
   - This will greatly increase the speed of system restoration
5) Disable AGC if the system’s operation is harming system security
   - For example, AGC may be pulsing units down during a low frequency condition
6) Be aware of generator off-normal frequency tripping relay settings
   - Also be aware of any delayed trip settings

**NERC Standards and Guidelines**

1) If a system determines that it is endangered by remaining interconnected, it may take such action as it deems necessary to protect its system
R. Policy 5E: System Restoration

[Reference the Electric System Restoration document in the NERC Operating Manual]

**Fundamental Knowledge**

1) Use of customer load during a restoration process
   ♦ At first, load is used as a tool to stabilize the system
   ♦ Eventually the focus of the restoration switches from stabilizing the system to restoring the customer load

2) Dangers of energizing long high-voltage lines during a system restoration
   ♦ Must have enough MVAr absorption capability on-line to control system voltages
   ♦ Especially dangerous to energize long high voltage cables due to their high natural capacitance

3) Techniques for controlling frequency during a system restoration
   ♦ May start with frequency slightly above 60 Hz before restoring blocks of load
   ♦ Limit the amount of load to restore in any one block to no more than a certain percentage of the available generation
     • For example, page 18 of the NERC restoration document states that load should be added in blocks no greater than 5% of the total synchronized generating capacity

4) Principal of cold load pick-up

**Terms**

1) Restoration
2) Blackout
3) Black-start
4) Black-start plan
5) Black-start unit
6) Island
7) Cold-load pick-up

**Concepts**

1) Purpose and content of any applicable Black-start plans
2) Importance of communication during a system restoration
3) Load restoration priorities
   ♦ Nuclear power plants
   ♦ Other power plants
   ♦ Critical loads
4) Use of the AGC system during a restoration event
   ♦ When to activate AGC
   ♦ Use of the different AGC modes
   ♦ AGC control versus governor control
5) Methods used to adjust schedules following loss of tie-lines
   ♦ Coordinate schedule cuts with all impacted control areas
   ♦ If tie-lines are lost, it is likely schedules must be cut
   ♦ Relationship between incorrect schedules and frequency deviations
6) Maintaining the demand to generation balance during a system restoration
   ♦ Hold frequency close to 60 Hz
7) Maintaining a VAr balance during a system restoration
   ♦ Excessive VAr supply will lead to high voltages
   ♦ VAr balance may be more difficult than the MW balance
NERC Standards and Guidelines

1) Policy 5E emphasizes:
   ♦ Importance of restoring power to nuclear power plants
   ♦ Importance of restoring power to oil-filled pipe-type cables
S. Policies 5F and 5G: Disturbance Reporting and Sabotage Reporting

Terms
1) Sabotage

NERC Standards and Guidelines
1) Follow applicable procedures and report incidents of sabotage to proper authorities

Fundamental Knowledge

1) Fundamentals of the unit commitment process
   ♦ Economic dispatch process for thermal units
     • Equal incremental cost
   ♦ Dispatch process for hydro based systems
2) Basic understanding of the methods used to conduct power system studies
   ♦ Software packages used to simulate system behavior
   ♦ Results accurate only for the conditions studied
   ♦ Studies are used in combination with actual operating data (flows, voltages, actual disturbance results, etc.) to set operating limits
3) Fundamentals of the load forecasting process
   ♦ Impact of temperature, wind, sun, humidity, etc.

Terms

1) Operating Plan
2) Operations planning
3) Operating studies
4) Unit commitment

Concepts

1) Adjust short term load forecasts based on actual system weather conditions
   ♦ Adjust unit commitment and dispatch order as required
2) Monitor weather forecasts and respond as required to severe weather forecasts
   ♦ Use of any applicable storm restoration plans
3) Continually review potential impacts of key outages and ensure system is prepared if such an event were to occur
   ♦ Use of operating tools such as a contingency analysis package

**Fundamental Knowledge**

1) Addressed in earlier policies

**Terms**

1) Line-loading relief procedures
2) Backup control center
3) Emergency operating plan

**Concepts**

1) Knowledge of current equipment operating limits
2) Knowledge of equipment (transmission lines, etc.) identification systems
   - For example, circuit identifiers for tie-lines
3) Implement (and monitor the results of) line loading relief procedures in order to reduce the power flow on a facility that has violated its operating limits
   - Ensure that most effective methods of reducing equipment overloads are employed
4) Given a system emergency, implement provisions of emergency operating plans
5) Monitor the generation supply and take whatever measures are required to achieve adequate generation levels
   - Switch fuel sources
   - Remove environmental restraints
   - Appeals to customers to start-up alternate generation sources
6) Activate emergency load reduction plans
   - Appeals for public load reduction
   - Use of voltage reduction
   - Use of interruptible and/or curtailable loads
   - Use of manual load shedding
7) Be prepared to operate system from a backup facility in case of loss of the primary control center facility
V. Policy 6C: Operations Planning – Automatic Load Shedding

Fundamental Knowledge

1) Addressed in earlier Policies
2) Differences in operating strategies when operating as part of a large Interconnection and when operating as part of a smaller island

Terms

1) Automatic isolation plan

Concepts

1) Monitor system frequency and respond to the activation of UFLS and generator off-normal frequency tripping relays
   ♦ Evaluate current conditions
   ♦ Stabilize frequency
   ♦ Ensure adequate operating reserves
   ♦ Restore system in coordination with neighboring system
2) Monitor system voltage and respond to the activation of UVLS schemes
   ♦ Evaluate current conditions
   ♦ Stabilize voltage
   ♦ Ensure adequate reactive power reserves
   ♦ Restore system in coordination with neighboring systems
3) When conditions require, activate any applicable automatic isolation plans
   ♦ Automatic isolation plans are permissible if isolating from the main system helps both the Interconnection and the system to be isolated
W. Policy 6D: Operations Planning – System Restoration

Fundamental Knowledge
1) Addressed in earlier Policies

Terms
1) Restoration plan

Concepts
1) Participate in drills to practice the use of a system restoration plan
   ♦ Consider impact of restoration actions on system protection
   ♦ Ensure restoration is coordinated with neighboring systems
   ♦ Be knowledgeable of preplanned and back-up synchronizing locations
2) Participate in drills to practice the black-start capability of black-start designated generators
3) Utilize a synchroscope to re-synchronize
4) Utilize backup telecommunications systems when primary systems fail
5) Following a major system break-up, operate SCADA master trip points if so provided
X. Policy 7: Telecommunications

Fundamental Knowledge

1) Types of telecommunication systems
   ♦ Microwave
   ♦ Satellite
   ♦ Fiber optic
   ♦ Power line carrier (PLC)
   ♦ Radio
   ♦ Telephone

2) Basic theory and impact of solar magnetic storms
   ♦ Solar storms can induce low frequency currents in the surface of the earth
   ♦ These low frequency currents can damage power transformers and lead to tripping of transformers, capacitors, and other equipment
   ♦ Every control area receives warnings on the likelihood of disturbances to the earth’s magnetic field
   ♦ K and A indices

Terms

1) Interregional Security Network (ISN)
2) Solar magnetic disturbances (SMD)
3) Eastern Interconnection Hotline
4) Regional Hotlines and Message Systems
5) Telemetry

Concepts

1) Utilize telecommunications facilities to effectively communicate with required personnel and/or systems
   ♦ Use of radio procedures
2) Assist with the regular testing of all telecommunications channels
   ♦ Voice channels
   ♦ SCADA
   ♦ AGC channels
   ♦ Protection channels
3) Respond to the loss of a protective relaying system’s telecommunications to ensure adequate protection is provided
4) Utilize backup telecommunication systems when appropriate
5) NERC Standards and Guidelines
6) Exclusive telecommunications channels shall be provided between the system control center and the control centers of each adjacent system
Y. Policy 8: Operator Personnel and Training

Terms
1) Operating authority

Concepts
1) Determine the extent of the system operator’s operating authority
2) Exercise operating authority to effectively operate the power system
3) Transfer and receive all required operating information
4) Utilize any available tools (dispatcher power flow, etc.) to gain information to assist with system operation
   ♦ Every system uses different tools

NERC Standards and Guidelines
1) System operators shall be delegated sufficient operating authority to operate their system in a stable and reliable manner
Appendix 9B – Energy Emergency Alerts
Version 2, Draft 4

Appendix Sections
A. General Requirements
B. Energy Emergency Alert Levels
C. Energy Emergency Alert 3 Report

Introduction
This Appendix provides the procedures by which a Load-Serving Entity can obtain capacity and energy when it has exhausted all other options and can no longer provide its customers’ expected energy requirements. NERC defines this situation as an “Energy Emergency.” NERC assumes that a capacity deficiency will manifest itself as an energy emergency.

The Energy Emergency Alert Procedure is initiated by the LSE’s RELIABILITY COORDINATOR, who declares various Energy Emergency Alert levels as defined in Section B, “Energy Emergency Alert Levels” to provide assistance to the LSE.

The LSE who requests this assistance is referred to as an “Energy Deficient Entity.”

NERC recognizes that Transmission Providers are subject to obligations under FERC-approved tariffs and other agreements, and nothing in these procedures should be interpreted as changing those obligations.
A. General Requirements

1. Initiated only by Reliability Coordinator. An Energy Emergency Alert may be initiated only by a RELIABILITY COORDINATOR at 1) the RELIABILITY COORDINATOR’s own request, or 2) upon the request of a CONTROL AREA, or 3) upon the request of a LOAD SERVING ENTITY. The cost of available resources shall not be a consideration for initiating an alert.

1.1. Situations for initiating Alert. An Energy Emergency Alert may be initiated for the following reasons:

- When the LSE is, or expects to be, unable to provide its customers’ energy requirements, and has been unsuccessful in locating other systems with available resources from which to purchase, or

- The LSE cannot schedule the resources due to, for example, ATC limitations or transmission loading relief limitations.

2. Notification. A RELIABILITY COORDINATOR who declares an Energy Emergency Alert shall notify all CONTROL AREAS and TRANSMISSION PROVIDERS in his RELIABILITY AREA. The RELIABILITY COORDINATOR shall also notify all other RELIABILITY COORDINATORS of the situation via the Reliability Coordinator Information System (RCIS). Additionally, conference calls between RELIABILITY COORDINATORS shall be held as necessary to communicate system conditions. The RELIABILITY COORDINATOR shall also notify the other RELIABILITY COORDINATORS when the Alert has ended.
B. Energy Emergency Alert Levels

Introduction
To ensure that all RELIABILITY COORDINATORS clearly understand potential and actual energy emergencies in the INTERCONNECTION, NERC has established three levels of Energy Emergency Alerts. The RELIABILITY COORDINATORS will use these terms when explaining energy emergencies to each other. An Energy Emergency Alert is an emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC Operating Policies or power supply contracts.

The RELIABILITY COORDINATOR may declare whatever Alert level is necessary, and need not proceed through the alerts sequentially.

1. Alert 1 – All available resources in use.

Circumstances:

- CONTROL AREA, RESERVE SHARING GROUP, or LOAD SERVING ENTITY foresees or is experiencing conditions where all available resources are committed to meet firm load, firm transactions, and reserve commitments, and is concerned about sustaining its required OPERATING RESERVES, and

- Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed

2. Alert 2 – Load management procedures in effect.

Circumstances:

- CONTROL AREA, RESERVE SHARING GROUP, or LOAD SERVING ENTITY is no longer able to provide its customers’ expected energy requirements, and is designated an ENERGY DEFICIENT ENTITY.

- ENERGY DEFICIENT ENTITY foresees or has implemented procedures up to, but excluding, interruption of firm load commitments. When time permits, these procedures may include, but are not limited to:
  - Public appeals to reduce demand
  - Voltage reduction
  - Interruption of non-firm end use loads in accordance with applicable contracts
  - Demand-side management
  - Utility load conservation measures

During Alert 2, RELIABILITY COORDINATORS, CONTROL AREAS, and ENERGY DEFICIENT ENTITIES have the following responsibilities:

2.1 Notifying other Control Areas and Market Participants. The ENERGY DEFICIENT ENTITY shall communicate its needs to other CONTROL AREAS and market participants.

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1 For emergency, not economic, reasons.
Upon request from the ENERGY DEFICIENT ENTITY, the respective RELIABILITY COORDINATOR shall post the declaration of the Alert level along with the name of the ENERGY DEFICIENT ENTITY and, if applicable, its CONTROL AREA on the NERC Web site

2.2 Declaration Period. The ENERGY DEFICIENT ENTITY shall update its RELIABILITY COORDINATOR of the situation at a minimum of every hour until the Alert 2 is terminated. The RELIABILITY COORDINATOR shall update the energy deficiency information posted on the NERC web site as changes occur and pass this information on to the affected RELIABILITY COORDINATORS, CONTROL AREAS, and Transmission Providers.

2.3 Sharing information on resource availability. CONTROL AREAS and market participants with available resources shall immediately contact the ENERGY DEFICIENT ENTITY. This should include the possibility of selling non-firm (recallable) energy out of available operating reserves. The ENERGY DEFICIENT ENTITY shall notify the RELIABILITY COORDINATORS of the results.

2.4 Evaluating and mitigating transmission limitations. The RELIABILITY COORDINATORS shall review all OPERATING SECURITY LIMITS and transmission loading relief procedures in effect that may limit the ENERGY DEFICIENT ENTITY’S scheduling capabilities. Where appropriate, the RELIABILITY COORDINATORS shall inform the Transmission Providers under their purview of the pending ENERGY EMERGENCY and request that they increase their Available Transfer Capability (ATC) by actions such as restoring transmission elements that are out of service, reconfiguring their transmission system, adjusting phase angle regulator tap positions, implementing emergency operating procedures, and reviewing generation redispatch options.

2.4.1 Notification of ATC adjustments. Resulting increases in ATCs shall be simultaneously communicated to the ENERGY DEFICIENT ENTITY and the market via posting on the appropriate OASIS sites by the Transmission Providers.

2.4.2 Availability of generation redispatch options. Available generation redispatch options shall be immediately communicated to the ENERGY DEFICIENT ENTITY by its RELIABILITY COORDINATOR.

2.4.3 Evaluating impact of current transmission loading relief events. The RELIABILITY COORDINATORS shall evaluate the impact of any current transmission loading relief events on the ability to supply emergency assistance to the ENERGY DEFICIENT ENTITY. This evaluation shall include analysis of system security and involve close communication among RELIABILITY COORDINATORS and the ENERGY DEFICIENT ENTITY.

2.4.4 Initiating inquiries on reevaluating OPERATING SECURITY LIMITS. The RELIABILITY COORDINATORS shall consult with the CONTROL AREAS and Transmission Providers in their RELIABILITY AREAS about the possibility of reevaluating and revising OPERATING SECURITY LIMITS.

2.5 Coordination of emergency responses. The RELIABILITY COORDINATOR shall communicate and coordinate the implementation of emergency operating responses.
2.6 ENERGY DEFICIENT ENTITY actions. Before declaring an Alert 3, the ENERGY DEFICIENT ENTITY must make use of all available resources. This includes but is not limited to:

2.6.1 All available generation units are on line. All generation capable of being on line in the time frame of the emergency is on line including quick-start and peaking units, regardless of cost.

2.6.2 Purchases made regardless of cost. All firm and non-firm purchases have been made, regardless of cost.

2.6.3 Non-firm sales recalled and contractually interruptible loads and DSM curtailed. All non-firm sales have been recalled, contractually interruptible retail loads curtailed, and Demand-side Management activated within provisions of the agreements.

2.6.4 Operating Reserves. Operating reserves are being utilized such that the ENERGY DEFICIENT ENTITY is carrying reserves below the required minimum or has initiated emergency assistance through its operating reserve sharing program.

3. Alert 3 – Firm load interruption imminent or in progress.

Circumstances:

- CONTROL AREA or LOAD SERVING ENTITY foresees or has implemented firm load obligation interruption. The available energy to the ENERGY DEFICIENT ENTITY, as determined from Alert 2, is only accessible with actions taken to increase transmission transfer capabilities.

3.1 Continue actions from Alert 2. The RELIABILITY COORDINATORS, and the ENERGY DEFICIENT ENTITY, shall continue to take all actions initiated during Alert 2. If the emergency has not already been posted on the NERC web site (see paragraph 2.1), the respective RELIABILITY COORDINATORS will, at this time, post on the web site information concerning the emergency.

3.2 Declaration Period. The ENERGY DEFICIENT ENTITY shall update its RELIABILITY COORDINATOR of the situation at a minimum of every hour until the Alert 3 is terminated. The RELIABILITY COORDINATOR shall update the energy deficiency information posted on the NERC web site as changes occur and pass this information on to the affected RELIABILITY COORDINATORS (via the RCIS), CONTROL AREAS, and Transmission Providers.

3.3 Use of Transmission short-time limits. The RELIABILITY COORDINATORS shall request the appropriate Transmission Providers within their RELIABILITY AREA to utilize available short-time transmission limits or other emergency operating procedures in order to increase transfer capabilities into the ENERGY DEFICIENT ENTITY.

3.4 Reevaluating and revising OPERATING SECURITY LIMITS. The RELIABILITY COORDINATOR of the ENERGY DEFICIENT ENTITY shall evaluate the risks of revising OPERATING SECURITY LIMITS on the reliability of the overall transmission system. Reevaluation of OPERATING SECURITY LIMITS shall be coordinated with other RELIABILITY COORDINATORS and only with the agreement of the CONTROL AREA or Transmission Provider whose equipment would be affected. The resulting increases in
transfer capabilities shall only be made available to the ENERGY DEFICIENT ENTITY who has declared an Energy Emergency Alert 3 condition. OPERATING SECURITY LIMITS shall only be revised as long as an Alert 3 condition exists or as allowed by the CONTROL AREA or Transmission Provider whose equipment is at risk. The following are minimum requirements that must be met before OPERATING SECURITY LIMITS are revised:

3.4.1 ENERGY DEFICIENT ENTITY obligations. The deficient CONTROL AREA or LOAD SERVING ENTITY must agree that, upon notification from its RELIABILITY COORDINATOR of the situation, it will immediately take whatever actions are necessary to mitigate any undue risk to the INTERCONNECTION. These actions may include load shedding.

3.4.2 Mitigation of cascading failures. The RELIABILITY COORDINATOR shall use his best efforts to ensure that revising OPERATING SECURITY LIMITS would not result in any cascading failures within the INTERCONNECTION.

3.5 Returning to pre-emergency OPERATING SECURITY LIMITS. Whenever energy is made available to an ENERGY DEFICIENT ENTITY such that the transmission systems can be returned to their pre-emergency OPERATING SECURITY LIMITS, the ENERGY DEFICIENT ENTITY shall notify its respective RELIABILITY COORDINATOR and downgrade the Alert.

3.5.1 Notification of other parties. Upon notification from the ENERGY DEFICIENT ENTITY that an Alert has been downgraded, the RELIABILITY COORDINATOR shall notify the affected RELIABILITY COORDINATORS (via the RCIS), CONTROL AREAS, and Transmission Providers that their systems can be returned to their normal OPERATING SECURITY LIMITS.

3.6 Reporting. Any time an Alert 3 is declared, the ENERGY DEFICIENT ENTITY shall complete the report listed in appendix 9B, Section C and submit this report to its respective RELIABILITY COORDINATOR within two business days of downgrading or termination of the Alert. Upon receiving the report, the RELIABILITY COORDINATOR shall review it for completeness and immediately forward it to the NERC staff for posting on the NERC web site. The RELIABILITY COORDINATOR shall present this report to the Reliability Coordinator Working Group at its next scheduled meeting.

4. Alert 0 - Termination. When the ENERGY DEFICIENT ENTITY believes it will be able to supply its customers’ energy requirements, it shall request of his RELIABILITY COORDINATOR that the EEA be terminated.

4.1. Notification. The RELIABILITY COORDINATOR shall notify all other RELIABILITY COORDINATORS via the RCIS of the termination. The RELIABILITY COORDINATOR shall also notify the affected CONTROL AREAS and TRANSMISSION PROVIDERS. The Alert 0 shall also be posted on the NERC web site if the original Alert was so posted.
C. Energy Emergency Alert 3 Report

NERC Policy 9B section B paragraph 3.5 requires that a Deficient Control Area or Load Serving Entity declaring a Energy Emergency Alert 3 must complete the following report. Upon completion of this report it is to be sent to the RELIABILITY COORDINATOR for review within two business days of the incident.

Requesting Control Area:

Entity experiencing energy deficiency (if different from Control Area):

Date/Time Implemented:

Date/Time Released:

Declared Deficiency Amount (MW):

Total Energy supplied by other Control Areas During the Alert 3 period:

Conditions that precipitated call for “Energy Deficiency Alert 3”: 
If “Energy Deficiency Alert 3” had not been called, would firm load be cut? If no, explain:

__________________________________________________________________________

__________________________________________________________________________

__________________________________________________________________________

Explain what action was taken in each step to avoid calling for “Energy Deficiency Alert 3”:

1. All generation capable of being on line in the time frame of the energy deficiency was on line (including quick start and peaking units) without regard to cost.

__________________________________________________________________________

__________________________________________________________________________

__________________________________________________________________________

2. All firm and nonfirm purchases were made regardless of cost.

__________________________________________________________________________

__________________________________________________________________________

__________________________________________________________________________

3. All nonfirm sales were recalled within provisions of the sale agreement.

__________________________________________________________________________

__________________________________________________________________________

__________________________________________________________________________
C. Energy Emergency Alert 3 Report

4. Interruptible load was curtailed where either advance notice restrictions were met or the interruptible load was considered part of spinning reserve.

5. Available load reduction programs were exercised (public appeals, voltage reductions, etc.).

6. Operating Reserves being utilized.

Comments:

Reported By: ______________________ Organization: ______________________

Title: ______________________
Appendix 9C1
Transmission Loading Relief Procedure – Eastern Interconnection

Version 2b

Appendix Subsections

A. General Requirements
B. Transmission Loading Relief (TLR) Levels
C. Interchange Transaction Curtailment Order
D. Transaction Management and Curtailment Process
E. Principles for Mitigating Constraints On and Off the Contract Path
F. Transaction Contribution Factor Calculation
G. Transaction Curtailment Formula
H. NERC Transmission Loading Relief Procedure Event Log

Terms

Transaction Reallocation (or Reallocation). The total or partial curtailment of TRANSACTIONS during TLR Level 3a or 5a to allow TRANSACTIONS using higher priority TRANSMISSION SERVICE to be implemented.

Curtailment Threshold. The minimum TRANSFER DISTRIBUTION FACTOR which, if exceeded, will subject an INTERCHANGE TRANSACTION to curtailment to relieve a transmission facility CONSTRAINT.

Introduction

The NERC Transmission Loading Relief (TLR) Procedure is an EASTERN INTERCONNECTION-wide procedure to allow the RELIABILITY COORDINATORS to:

1. Respect TRANSMISSION SERVICE reservation priorities, and
2. Mitigate potential or actual OPERATING SECURITY LIMIT violations.

Transmission Provider Obligations

NERC recognizes that TRANSMISSION PROVIDERS are subject to obligations under FERC-approved tariffs or other agreements, and nothing in these procedures shall be interpreted as changing those obligations. This Appendix uses the term “transmission reservation” to mean transmission arranged under the FERC pro forma tariff as well as under other transmission agreements.

Relationship between TLR Procedure and FERC pro forma Tariff

The TLR Procedure has been incorporated into the transmission tariff of many TRANSMISSION PROVIDERS, and is on file with the Federal Energy Regulatory Commission. The TLR Procedure follows the curtailment provisions of the pro forma tariff with regards to Non-firm and Firm Point-to-Point Transmission Service, and Network Integration Transmission Service.
Appendix 9C1 – Transmission Loading Relief Procedure

Introduction

TLR Procedure curtails Transactions. The pro forma tariff’s curtailment provision addresses the curtailment of the transmission service over the CONSTRAINED FACILITIES, not curtailment of the generation product being sold via that service. The tariff does not consider the effect of the curtailment on the load-serving entity; instead, it considers the obligations of the TRANSMISSION PROVIDER(S) in providing or curtailing the Transmission Service. The NERC TLR Procedure translates the curtailment of the Transmission Service into a curtailment of the actual MW flow over the constraint.

Considerations for Firm Point-to-Point Transmission Service.

Transactions using Firm Point-to-Point Transmission Service are afforded the highest priority. Therefore, in many situations, the TLR Procedure will allow these Transactions to start during the implementation of a TLR 2, 3a, 3b, and 4. Please refer to Sections B.2. through B.5. and “Appendix 9C1C – Interchange Transaction Curtailments During TLR Level 3b” for details.

Re-dispatch considerations. Regarding the curtailment of transmission use by Firm Point-to-Point Transmission Service, the TLR Procedure follows the Federal Energy Regulatory Commission’s pro forma tariff that TRANSMISSION PROVIDERS are not obligated to re-dispatch their own resources to maintain TRANSACTIONS using Firm Point-to-Point Transmission Service before they are curtailed on a pro-rata basis with transmission use for Network Integration Transmission Service and Native Load.

Curtailment of Service to Network and Native Load customers. The TLR Procedure includes the calculation of the Transaction Contribution Factor (TCF), which determines the portion of the CONSTRAINED FACILITY’S loading due to Firm Point-to-Point Transmission Service. This is one part of the calculation that the RELIABILITY COORDINATOR must perform to ensure that this curtailment is comparable and non-discriminatory with the curtailment of Network Integration Transmission Service and Transmission Service for Native Load. (See Section F, “Parallel Flow Calculation Procedure for Reallocating or Curtailing Firm Transmission Service”)

Version 2b A9C1-2 Approved by Board of Trustees:
October 8, 2002
## Summary of TLR Levels

<table>
<thead>
<tr>
<th>TLR Level</th>
<th>RELIABILITY COORDINATOR Action</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Notify RELIABILITY COORDINATORS of potential OPERATING SECURITY LIMIT violations</td>
<td>Of those transactions at or above the CURTAILMENT THRESHOLD, only those under existing Transmission Service reservations will be allowed to continue, and only to the level existing at the time of the hold. Transactions using Firm Point-to-Point Transmission Service are not held. See Section B.1.</td>
</tr>
<tr>
<td>2</td>
<td>Hold INTERCHANGE TRANSACTIONS at current levels to prevent OPERATING SECURITY LIMIT violations</td>
<td>Curtailment follows Transmission Service priorities. Higher priority transactions are enabled to start by the REALLOCATION process. See Section B.3.</td>
</tr>
<tr>
<td>3a</td>
<td>Reallocation Transactions using Non-firm Point-to-Point Transmission Service are curtailed to allow Transactions using higher priority Point-to-Point Transmission Service</td>
<td>Curtailment follows Transmission Service priorities. Higher priority transactions are enabled to start by the REALLOCATION process. See Section B.3.</td>
</tr>
<tr>
<td>3b</td>
<td>Curtail Transactions using Non-firm Point-to-Point Transmission Service to mitigate Operating Security Limit Violation</td>
<td>Curtailment follows Transmission Service priorities. Higher priority transactions are enabled to start by the REALLOCATION process. See Section B.3.</td>
</tr>
<tr>
<td>4</td>
<td>Reconfigure transmission system to allow Transactions using Firm Point-to-Point Transmission Service to continue</td>
<td>There may or may not be an OPERATING SECURITY LIMIT violation. There are special considerations for handling Transactions using Firm Point-to-Point Transmission Service. See Section B.5.</td>
</tr>
<tr>
<td>5a</td>
<td>Reallocation Transactions using Firm Point-to-Point Transmission Service are curtailed (pro rata) to allow new Transactions using Firm Point-to-Point Transmission Service to begin (pro rata).</td>
<td>Attempts to accommodate all Transactions using Firm Point-to-Point Transmission Service, though at a reduced (“pro rata”) level. Pro forma tariff also requires curtailment / REALLOCATION on pro rata basis with Network Integration Transmission Service and Native Load. See Section B.6.</td>
</tr>
<tr>
<td>6</td>
<td>Emergency Action</td>
<td>Could include demand-side management, re-dispatch, voltage reductions, interruptible and firm load shedding. See Section B.8.</td>
</tr>
<tr>
<td>0</td>
<td>TLR Concluded</td>
<td>Restore transactions. See Section B.9.</td>
</tr>
</tbody>
</table>

Unless explained otherwise, “curtailment” refers to those INTERCHANGE TRANSACTIONS whose DISTRIBUTION FACTOR on the CONSTRAINED FACILITY exceeds the CURTAILMENT THRESHOLD.
Appendix 9C1 – Transmission Loading Relief Procedure

Introduction

Posting TLR Events

When the RELIABILITY COORDINATOR initiates the TLR Procedure, he will notify all other RELIABILITY COORDINATORS via the RCIS. Furthermore, the TLR Level will be posted to the appropriate NERC web page(s).

Notification – TLR Level 1

This Level is an alert to inform the marketplace and other RELIABILITY COORDINATORS that curtailments are likely to occur. The RELIABILITY COORDINATOR should announce a TLR 0 once the Notification level is no longer necessary.

Hold – TLR Level 2

If an OPERATING SECURITY LIMIT violation is imminent, the RELIABILITY COORDINATOR shall direct his CONTROL AREAS to maintain INTERCHANGE TRANSACTIONS such that, of those transactions that are at or above the CURTAILMENT THRESHOLD, only those under existing Transmission Service reservations will be allowed to continue, and only to the level existing at the time of the hold. During TLR Level 2, the RELIABILITY COORDINATOR will allow existing INTERCHANGE TRANSACTIONS to increase, or new INTERCHANGE TRANSACTIONS to begin, if they help mitigate the CONSTRAINT. TRANSACTIONS using Firm Point-to-Point Transmission Service will be allowed to start.

TLR Level 2 is a transient state, which requires a quick decision to proceed to higher TLR Levels (3 and above) to allow INTERCHANGE TRANSACTIONS to be implemented according to their transmission reservation priority. The time for being in TLR Level 2 should be no more than 30 minutes, with the understanding that there may be circumstances where this time may be exceeded. If the time in TLR Level 2 exceeds 30 minutes, the RELIABILITY COORDINATOR must document this action on the TLR Log. When faced with a new INTERCHANGE TRANSACTION using higher priority Point-to-Point Transmission Service, the RELIABILITY COORDINATOR must immediately proceed to TLR Level 3a to curtail those INTERCHANGE TRANSACTIONS using lower priority Point-to-Point Transmission Service. He must give preference to those INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission Service, followed by those using higher priority Non-firm Point-to-Point Transmission Service. The RELIABILITY COORDINATORS shall monitor and coordinate the timing of the curtailment and reallocation process.

1 We are using the term Reliability Coordinator Information System (RCIS) in this Appendix in the general sense for whatever information system that has been established for disseminating TLR information. In some cases, it could actually be the Interchange Distribution Calculator system.
Appendix 9C1 – Transmission Loading Relief Procedure

Introduction

Curtailing – TLR Levels 3a, 3b, 5a, 5b

Curtailments are required for two reasons:

1. To allow an INTERCHANGE TRANSACTION using a higher priority Transmission Service to begin when it would otherwise cause an OPERATING SECURITY LIMIT Violation (called “Reallocation” – TLR Level 3a, and 5a), and

2. To mitigate an imminent or existing OPERATING SECURITY LIMIT Violation (TLR Level 3b and 5b). 2

Should curtailment become necessary by using TLR 3b or 5b to mitigate a potential or actual OPERATING SECURITY LIMIT violation, INTERCHANGE TRANSACTIONS whose Transfer Distribution Factors (TDF) across the specific CONSTRAINED FACILITY are at or above the CURTAILMENT THRESHOLD shall be curtailed whenever practicable on a proportional basis and according to these Procedures as explained in Section G, “Transaction Curtailment Formula.” The order of INTERCHANGE TRANSACTION curtailment is explained in Section C, “Interchange Transaction Curtailment Order.” Some TRANSACTIONS using Firm Point-to-Point Transmission Service will be allowed to start during TLR 3b. See Section B, “Transmission Loading Relief (TLR) Levels,” and Appendix 9C1C, “Interchange Transaction Curtailments During TLR Level 3b,” for details.

These curtailments will remain in effect until such time as the CONSTRAINT has been mitigated, allowing the INTERCHANGE TRANSACTIONS to be restored.

Reconfiguration – TLR Level 4

Before the RELIABILITY COORDINATOR orders curtailment of INTERCHANGE TRANSACTIONS using Firm Point-to-Point TRANSMISSION SERVICE (TLR Level 5a or 5b), he will request the TRANSMISSION PROVIDERS in his RELIABILITY AREA to attempt to reconfigure their transmission systems to allow the INTERCHANGE TRANSACTIONS to continue. Transmission reconfiguration may be implemented as long as it does not jeopardize the operating security of the INTERCONNECTION. Transactions using Non-firm Point-to-Point Transmission Service will be curtailed or held from starting. Some Transactions using Firm Point-to-Point Transmission Service will be allowed to start. See Section B, “Transmission Loading Relief (TLR) Levels,” and Section F, “Parallel Flow Calculation Procedure for Reallocating or Curtailing Firm Transmission Service” for details.

Emergency Procedures – TLR Level 6

If the RELIABILITY COORDINATOR is unable to mitigate the CONSTRAINT through the use of TLR Levels 3, 4, or 5, then he has the authority to immediately direct the CONTROL AREAS to take actions such as re-dispatch generation, reconfigure transmission, or reduce load to mitigate the critical condition until INTERCHANGE TRANSACTIONS can be reduced utilizing the TLR Interchange Transaction Curtailment Order, or other methods, to return the system to a reliable state. All CONTROL AREAS shall comply with all requests from their RELIABILITY COORDINATOR. However, the CONTROL AREA operator should immediately notify his RELIABILITY COORDINATOR if the RELIABILITY COORDINATOR’S request is unclear or would seem to cause an operating problem.

2 This includes mitigation of contingency overloads.
Return to Normal Operations – TLR Level 0

The RELIABILITY COORDINATOR that is experiencing the CONSTRAINT within its RELIABILITY AREA shall notify all RELIABILITY COORDINATORS via the RCIS when the adverse conditions are mitigated and the system is in a “normal” state.

**Considerations for Constraints On and Off the Contract Path**

Interchange Transaction Priority **ON** the Contract Path

If the CONSTRAINED FACILITY is on the contract path, the curtailment priority will be equal to the TRANSMISSION SERVICE priority of the link on which the CONSTRAINED FACILITY is located. [Section E., “Principles for Mitigating Constraints On and Off the Contract Path”]

Interchange Transaction Priority **OFF** the Contract Path

If the CONSTRAINED FACILITY is not on the contract path of the INTERCHANGE TRANSACTION, the curtailment priority will be equal to the lowest Transmission Service priority of the links on the contract path. (This means that an INTERCHANGE TRANSACTION using Firm Point-to-Point Transmission Service on all contract path links is considered a “firm” INTERCHANGE TRANSACTION even if the CONSTRAINED FACILITY is off the contract path.)

**Re-dispatch and Other Congestion Management Options**

Some TRANSMISSION PROVIDERS offer re-dispatch or other congestion management options that allow a Transmission Customer to mitigate the effect of its INTERCHANGE TRANSACTION on the CONSTRAINED FACILITY. If the Transmission Customer elects to use such an option, the RELIABILITY COORDINATOR must treat the INTERCHANGE TRANSACTION accordingly in the curtailment scheme. (Note: “Local” congestion management procedures require approval by NERC if they are to be used in lieu of the TLR Procedure prescription. See Policy 9.C. Requirement 3.2.1.1.)
A. General Requirements

1. Initiation only by RELIABILITY COORDINATOR. The NERC Transmission Loading Relief Procedure may be initiated only by a RELIABILITY COORDINATOR at 1) the RELIABILITY COORDINATOR’S own request, or 2) upon the request of a Transmission Provider or CONTROL AREA.

2. Mitigating transmission constraints. The TLR Procedure may be used to mitigate potential or actual OPERATING SECURITY LIMIT violations on any transmission facility modeled in the INTERCHANGE DISTRIBUTION CALCULATOR. [See also Section 6.1, “Interchange Transactions not in the IDC.”]

2.1. Requesting relief on tie facilities. Any TRANSMISSION PROVIDER or CONTROL AREA who operates the tie facility may request relief from its RELIABILITY COORDINATOR.

2.1.1. INTERCHANGE TRANSACTION priority on tie facilities. The priority of the INTERCHANGE TRANSACTION(S) to be curtailed is determined by the Transmission Service reserved on the Transmission Provider’s system who requested the relief.

3. Order of TLR Levels and taking emergency action. The RELIABILITY COORDINATOR may not necessarily follow the TLR Levels in their numerical order (See Section B, “TLR Levels”). Furthermore, if a RELIABILITY COORDINATOR deems that a transmission loading condition could jeopardize bulk system reliability, the RELIABILITY COORDINATOR has the authority to enter TLR Level 6 directly, and immediately direct the CONTROL AREAS to take such actions as re-dispatch generation, or reconfigure transmission, or reduce load to mitigate the critical condition until INTERCHANGE TRANSACTIONS can be reduced utilizing the TLR Transaction Curtailment Procedures, or other methods, to return the system to a secure state.

4. Notification of TLR Procedure implementation. The RELIABILITY COORDINATOR initiating the use of the TLR Procedure must notify other RELIABILITY COORDINATORS and CONTROL AREAS, and must post the initiation and progress of the TLR event on the appropriate NERC web page(s).

4.1. Notifying other RELIABILITY COORDINATORS. The RELIABILITY COORDINATOR initiating the TLR Procedure shall inform all other RELIABILITY COORDINATORS via the RELIABILITY COORDINATOR Information System (RCIS) that the TLR Procedure has been implemented.

4.1.1. Actions expected. The RELIABILITY COORDINATOR initiating the TLR Procedure shall indicate the actions expected to be taken by other RELIABILITY COORDINATORS. [See also: Policy 3B and 3D for CONTROL AREA Requirements during curtailments.]

4.2. Notifying TRANSMISSION PROVIDERS and CONTROL AREAS. RELIABILITY COORDINATORS must keep the TRANSMISSION PROVIDERS and CONTROL AREAS in his RELIABILITY AREA informed when entering and leaving any TLR level.

4.3. Notifying Control Areas. The RELIABILITY COORDINATOR for the SINK CONTROL AREA is responsible for directing that CONTROL AREA to curtail the INTERCHANGE TRANSACTIONS as specified by the RELIABILITY COORDINATOR implementing the TLR Procedure. [See Policy 3.D. for Control Area curtailment notification details.]
**A. General Requirements**

4.3.1. **Notification order.** Within a Transmission Service priority level, the SINK CONTROL AREAS whose INTERCHANGE TRANSACTIONS have the largest impact on the CONSTRAINED FACILITIES shall be notified first if practicable.

4.4. **Updates.** At least once each hour, or when conditions change, the RELIABILITY COORDINATOR implementing the TLR Procedure shall update all other RELIABILITY COORDINATORS (via the RCIS). TRANSMISSION PROVIDERS and CONTROL AREAS who have had Interchange Transactions impacted by the TLR will be updated by their RELIABILITY COORDINATOR.

5. **Obligations.** All RELIABILITY COORDINATORS must comply with the request of the RELIABILITY COORDINATOR who initiated the TLR Procedure, unless the initiating RELIABILITY COORDINATOR agrees otherwise.

5.1. **Use of TLR Procedure with “local” procedures.** A RELIABILITY COORDINATOR may implement a local transmission loading relief or congestion management procedure simultaneously with an INTERCONNECTION-wide procedure. However, he is obligated to follow the curtailments as directed by the INTERCONNECTION-wide procedure. If the RELIABILITY COORDINATOR desires to use a local procedure as a substitute for curtailments as directed by the INTERCONNECTION-wide procedure, he may do so only if such use is approved by the NERC Operating Reliability Subcommittee and Operating Committee.

6. **Consideration of Interchange Transactions.** The administration of the TLR Procedure is guided by information obtained from the Interchange Distribution Calculator (IDC).

6.1. **Interchange Transactions not in the IDC.** RELIABILITY COORDINATORS shall also treat known INTERCHANGE TRANSACTIONS that may not appear in the IDC in accordance with the procedures in this document.

6.2. **Transmission elements not in IDC.** When a RELIABILITY COORDINATOR is faced with an overload on a transmission element that is not modeled in the IDC, the RELIABILITY COORDINATOR shall use the best information available to curtail INTERCHANGE TRANSACTIONS in order to operate the system in a reliable manner. The RELIABILITY COORDINATOR shall use his best efforts to ensure that INTERCHANGE TRANSACTIONS with a TRANSFER DISTRIBUTION FACTOR of less than the CURTAILMENT THRESHOLD on the transmission element not modeled in the IDC are not curtailed.

6.3. **Questionable IDC results.** Any RELIABILITY COORDINATOR (or TRANSMISSION PROVIDER through his RELIABILITY COORDINATOR) who believes the curtailment list from the IDC for a particular TLR event is incorrect shall use his best efforts to communicate those adjustments necessary to bring the curtailment list into conformance with the principles of this Procedure to the initiating RELIABILITY COORDINATOR. Causes of questionable IDC results may include:

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3 Examples would be 1) a local procedure that curtails INTERCHANGE TRANSACTIONS in a different order or ratio than the INTERCONNECTION-wide procedure, or 2) a local re-dispatch procedure.
Appendix 9C1 – Transmission Loading Relief Procedure

A. General Requirements

- Missing INTERCHANGE TRANSACTIONS that are known to contribute to the CONSTRAINT.
- Significant change in transmission system topology
- TDF matrix error.

Impacts of questionable IDC results may include:
- Curtailment that would have no effect on, or aggravate the constraint.
- Curtailment that would initiate a constraint elsewhere.

If other RELIABILITY COORDINATORS are involved in the TLR event, agreement must be reached with the initiating RELIABILITY COORDINATORS on any adjustments to the curtailment list.

6.4. Curtailment that would cause a constraint elsewhere. If the RELIABILITY COORDINATOR is aware that an INTERCHANGE TRANSACTION curtailment directed by the IDC would cause a constraint to occur elsewhere, after consulting with those RELIABILITY COORDINATORS who initiated the curtailment, he may exempt that INTERCHANGE TRANSACTION from curtailment.

6.5. Re-dispatch options. The RELIABILITY COORDINATOR shall ensure that INTERCHANGE TRANSACTIONS that are linked to re-dispatch options are protected from curtailment in accordance with the re-dispatch provisions. [See also: Policy 9C. Req. 3.2.1.1 on use of local procedures.]

6.6. Reallocation. During a TLR Level 3A, TRANSACTIONS of higher priority that meet the Approved-tag Submission Deadline for Reallocation will be considered for REALLOCATION (see Appendix 9C1B, “Interchange Transaction Reallocation During TLR Levels 3a and 5a.”) During a TLR Level 5A, TRANSACTIONS using Firm Transmission Service will be considered for REALLOCATION if they have met the same tag submission deadlines.

7. IDC updates. Any INTERCHANGE TRANSACTION adjustments or curtailments that result from using this Procedure must be entered into the IDC as explained in Policy 9C. Requirement 1.1.

8. Logging. The RELIABILITY COORDINATOR shall complete the NERC Transmission Loading Relief Procedure Log (Section I) whenever he invokes TLR Level 2 or above, and send a copy of the log via e-mail to the NERC staff within two business days of the TLR event. The staff will post these logs on the NERC web site upon receipt.

9. TLR Event Review. The RELIABILITY COORDINATOR shall report the TLR event to the NERC Market Interface Committee and Operating Reliability Subcommittee in accordance with TLR review processes established by NERC as required.

9.1. Providing information. CONTROL AREAS within the RELIABILITY COORDINATOR’S RELIABILITY AREA, and all other RELIABILITY COORDINATORS, including CONTROL AREAS within their respective RELIABILITY AREAS, shall provide information, as requested by the initiating RELIABILITY COORDINATOR, in accordance with TLR review processes established by NERC.
9.2. **Market Interface Committee reviews.** The Market Interface Committee may conduct reviews of certain TLR events based on the size and number of INTERCHANGE TRANSACTIONS that are affected, the frequency that the TLR Procedure is called for a particular CONSTRAINED FACILITY, or other factors.

9.3. **Operating Reliability Subcommittee reviews.** The Operating Reliability Subcommittee will conduct reviews to ensure proper implementation and for “lessons learned.”
B. Transmission Loading Relief (TLR) Levels

Introduction

This section describes the various levels of the TLR Procedure. The description of each level begins with the circumstances that define the TLR Level, followed by the procedures to be followed.

The decision that a RELIABILITY COORDINATOR makes in selecting a particular TLR Level often depends on the transmission loading condition and whether the INTERCHANGE TRANSACTION is using Non-firm Point-to-Point Transmission Service or Firm Point-to-Point Transmission Service. There are further considerations that depend on whether the Constrained Facility is on or off the contract path. (Section E., “Principles for Mitigating Constraints On and Off the Contract Path”) It is important to note, as explained in the Introduction, that an INTERCHANGE TRANSACTION using Firm Point-to-Point Transmission Service on all contract path links is considered a “firm” INTERCHANGE TRANSACTION even if the CONSTRAINED FACILITY is off the contract path.

TLR Levels

1. TLR Level 1 – Notify RELIABILITY COORDINATORS of potential Operating Security Limit Violations.
   1.1. Circumstances:
   • The transmission system is secure.
   • The RELIABILITY COORDINATOR foresees a transmission or generation contingency or other operating problem within his RELIABILITY AREA that could cause one or more transmission facilities to approach or exceed their OPERATING SECURITY LIMIT.
   1.2. Notification procedures. The RELIABILITY COORDINATOR shall notify all RELIABILITY COORDINATORS via the Reliability Coordinator Information System as soon as the condition is foreseen. All affected RELIABILITY COORDINATORS shall check to ensure that INTERCHANGE TRANSACTIONS are posted in the INTERCHANGE DISTRIBUTION CALCULATOR.

2. TLR Level 2 – Hold transfers at present level to prevent Operating Security Limit Violations
   2.1. Circumstances for entering this level:
   • The transmission system is secure,
   • One or more transmission facilities are expected to approach, or are approaching, or are at their OPERATING SECURITY LIMIT.
   2.2. Holding procedures. The RELIABILITY COORDINATOR may hold the implementation of any additional INTERCHANGE TRANSACTIONS that are at or above the CURTAILMENT THRESHOLD. However, the RELIABILITY COORDINATOR should allow additional INTERCHANGE TRANSACTIONS that flow across the CONSTRAINED FACILITY if their flow reduces the loading on the Constrained Facility or has a Transfer Distribution Factor less than the CURTAILMENT THRESHOLD. All INTERCHANGE TRANSACTIONS using

Treatment of Firm Transactions.
Appendix 9C1 – Transmission Loading Relief Procedure

B. Transmission Loading Relief (TLR) Levels

Firm Point-to-Point Transmission Service will be allowed to start.

2.2.1. TLR Level 2 is a transient state, which requires a quick decision to proceed to higher TLR Levels (3 and above) to allow INTERCHANGE TRANSACTIONS to be implemented according to their transmission reservation priority. The time for being in TLR Level 2 should be no more than 30 minutes, with the understanding that there may be circumstances where this time may be exceeded. If the time in TLR Level 2 exceeds 30 minutes, the RELIABILITY COORDINATOR must document this action on the TLR Log.

3. TLR Level 3a – Reallocation of Transmission Service by curtailing INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Transmission Service to allow INTERCHANGE TRANSACTIONS using higher priority Transmission Service.

3.1. Circumstances for entering this level:

- The transmission system is secure
- One or more transmission facilities are expected to approach, or are approaching, or are at their OPERATING SECURITY LIMIT
- TRANSACTIONS using Non-firm Point-to-Point Transmission Service are flowing that are at or above the Curtailment Threshold on those facilities.
- The Transmission Provider has previously approved a higher priority Point-to-Point Transmission Service reservation over which a Transmission Customer wishes to begin an INTERCHANGE TRANSACTION. (See Section 3.2 below)

3.2. Reallocation procedures to allow INTERCHANGE TRANSACTIONS using higher priority Point-to-Point Transmission Service to start. The RELIABILITY COORDINATOR with the constraint shall give preference to those INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission Service, followed by those using higher priority Non-firm Point-to-Point Transmission Service as specified in Section C. “Interchange Transaction Curtailment Order.” INTERCHANGE TRANSACTIONS that have been held or curtailed as prescribed in this Section shall be reallocated (reloaded) according to their Transmission Service priorities when operating conditions permit. The specifications for performing this Reallocation, as well as the Tagging requirements, are found in Appendix 9C1B, “Interchange Transaction Reallocation During TLR Level 3a and 5a.”

3.2.1. INTERCHANGE TRANSACTIONS using higher priority Non-firm or Firm Transmission Service will displace INTERCHANGE TRANSACTIONS with lower priority Transmission Service.

3.2.2. INTERCHANGE TRANSACTIONS using Non-firm Transmission Service will not be curtailed to allow the start or increase of another INTERCHANGE TRANSACTION having the same priority Non-firm Transmission Service.

3.2.3. If there are insufficient INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Transmission Service that can be curtailed to allow for INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission Service to begin, the RELIABILITY COORDINATOR will proceed to TLR Level 5a. (See Section 6, “TLR Level 5a,” and Appendix 9C1B “Interchange Transaction...”
Curtailments During TLR Levels 3a and 5a,” for Reallocation of Interchange Transactions using Firm Point-to-Point Transmission Service)

3.2.4. Reloading of curtailed INTERCHANGE TRANSACTIONS will precede starting of new or increased INTERCHANGE TRANSACTIONS.

3.2.4.1. Interchange Transactions whose tags were submitted to the Tag Authority prior to the TLR Level 2 or Level 3a being called, but were subsequently held from starting, are considered to have been curtailed and thus would be reloaded the same time as the curtailed INTERCHANGE TRANSACTIONS.

3.2.5. Transmission capability available for reloading or starting will be filled by eligible TRANSACTIONS on a pro-rata basis.

3.2.6. Transactions whose tags meet the Approved-tag Submission Deadline for Reallocation (see Appendix 9C1B, “Interchange Transaction Reallocation During TLR Level 3a and 5a,” Section B) will be considered for reallocation for the upcoming hour. Tags submitted after this deadline will be considered for reallocation the following hour.

4. TLR Level 3b – Curtail INTERCHANGE TRANSACTIONS using Non-Firm Transmission Service Arrangements to mitigate an OPERATING SECURITY LIMIT Violation

4.1. Circumstances for entering this level:

- One or more transmission facilities are operating above their OPERATING SECURITY LIMIT, or
- Such operation is imminent and it is expected that facilities will exceed their security limit unless corrective action is taken, or
- One or more Transmission Facilities will exceed their OPERATING SECURITY LIMIT upon the removal from service of a generating unit or another transmission facility
- TRANSACTIONS using Non-firm Point-to-Point Transmission Service are flowing that are at or above the Curtailment Threshold on those facilities.

4.2. Holding new INTERCHANGE TRANSACTIONS. The RELIABILITY COORDINATOR shall hold all new INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Transmission Service that are at or above the CURTAILMENT THRESHOLD during the period of the OPERATING SECURITY LIMIT Violation. INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission Service will be allowed to start if they are submitted to the IDC within specific time limits as explained in Appendix 9C1C, “Interchange Transaction Curtailments During TLR Level 3b.”

4.3. Curtailment procedures to mitigate an OPERATING SECURITY LIMIT. The RELIABILITY COORDINATOR shall curtail INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Transmission Service that are at or above the CURTAILMENT THRESHOLD as specified in Section C. “Interchange Transaction Curtailment Order.”
5. **TLR Level 4 – Reconfigure Transmission**

5.1. **Circumstances for entering this level:**

- One or more Transmission Facilities are above their OPERATING SECURITY LIMIT, or
- Such operation is imminent and it is expected that facilities will exceed their security limit unless corrective action is taken

5.2. **Holding new INTERCHANGE TRANSACTIONS.** The RELIABILITY COORDINATOR shall hold all new INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Transmission Service that are at or above the CURTAILMENT Threshold during the period of the OPERATING SECURITY LIMIT Violation. INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission Service will be allowed to start if they are submitted to the IDC by 00:25 or the time at which the TLR Level 4 is called, whichever is later.

5.3. **Reconfiguration procedures.** Following the curtailment of all INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Transmission Service that are at or above the CURTAILMENT Threshold in Level 3b that impact the CONSTRAINED FACILITIES, if an OPERATING SECURITY LIMIT violation is imminent or occurring, the RELIABILITY COORDINATOR(IES) shall request that the affected TRANSMISSION PROVIDERS reconfigure transmission on their system, or arrange for reconfiguration on other transmission systems, to mitigate the constraint. Specific details are explained in Section E., “Principles for Mitigating Constraints On and Off the Contract Path”

6. **TLR Level 5a – Reallocation of Transmission Service by curtailing INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission Service on a pro rata basis to allow additional INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission Service.**

6.1. **Circumstances:**

- The transmission system is secure
- One or more transmission facilities are at their OPERATING SECURITY LIMIT
- All INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Transmission Service that are at or above the CURTAILMENT Threshold have been curtailed.
- The TRANSMISSION PROVIDER has been requested to begin an INTERCHANGE TRANSACTION using previously arranged Firm Transmission Service that would result in an OPERATING SECURITY LIMIT Violation.
- No further transmission reconfiguration is possible or effective.

6.2. **Reallocation procedures to allow new INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission Service to start.** Reallocation of INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission Service is a three-step process as follows:

6.2.1. **Step 1 – Identify available re-dispatch options.** The RELIABILITY COORDINATOR shall assist the Transmission Provider(s) in identifying those known re-dispatch options that are available to the Transmission Customer that will mitigate the loading on the CONSTRAINED FACILITIES. If such re-dispatch options are deemed insufficient to mitigate loading on the CONSTRAINED FACILITIES, the RELIABILITY COORDINATOR shall proceed to implement these options while proceeding to Steps 2 and 3 below.
6.2.2. **Step 2** – The RELIABILITY COORDINATOR shall calculate the percent of the overload on the CONSTRAINED FACILITY caused by both Firm Point-to-Point Transmission Service (at or above the CURTAILMENT THRESHOLD) and the TRANSMISSION PROVIDER’S Network Integration Transmission Service and Native Load, as required by the TRANSMISSION PROVIDER’S filed tariff. This is described in Section F, “Parallel Flow Calculation Procedure for Reallocation or Curtailing Firm Transmission Service.”

6.2.3. **Step 3** – Curtail Interchange Transactions using Firm Transmission Service. The RELIABILITY COORDINATOR shall curtail or reallocate on a pro-rata basis (based on the MW level of the MW total to all such INTERCHANGE TRANSACTIONS), those INTERCHANGE TRANSACTIONS as calculated in Section 7.2.2 over the CONSTRAINED FACILITIES. (See also Appendix 9C1B, “Interchange Transaction Reallocation During TLR 3a and 5a.”) The RELIABILITY COORDINATOR shall assist the Transmission Provider in curtailing Transmission Service to Network Integration Transmission Service customers and Native Load if such curtailments are required by the Transmission Provider’s tariff. Available re-dispatch options will continue to be implemented.

7. **TLR Level 5b – Curtail INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission Service to mitigate an OPERATING SECURITY LIMIT Violation.**

7.1. **Circumstances:**

- One or more Transmission Facilities are operating above their OPERATING SECURITY LIMIT, or
- Such operation is imminent, or
- One or more Transmission Facilities will exceed their OPERATING SECURITY LIMIT upon the removal from service of a generating unit or another transmission facility.
- All INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Transmission Service that are at or above the CURTAILMENT THRESHOLD have been curtailed.
- No further transmission reconfiguration is possible or effective.

7.2. Curtailment of INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission Service is a three-step process as follows:

7.2.1. **Step 1 – Identify available re-dispatch options.** The RELIABILITY COORDINATOR shall assist the Transmission Provider(s) in identifying those known re-dispatch options that are available to the Transmission Customer that will mitigate the loading on the CONSTRAINED FACILITIES. If such re-dispatch options are deemed insufficient to mitigate loading on the CONSTRAINED FACILITIES, the RELIABILITY COORDINATOR shall proceed to implement these options while proceeding to Steps 2 and 3 below.

7.2.2. **Step 2** – The RELIABILITY COORDINATOR shall calculate the percent of the overload on the CONSTRAINED FACILITY caused by both, Firm Point-to-Point Transmission Service (at or above the CURTAILMENT THRESHOLD) and the TRANSMISSION PROVIDER’S Network Integration Transmission Service and Native Load, as required by the TRANSMISSION PROVIDER’S filed tariff. This is...
Appendix 9C1 – Transmission Loading Relief Procedure

B. Transmission Loading Relief (TLR) Levels

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7.2.3. **Step 3 – Curtailment of Interchange Transactions using Firm Transmission Service.** At this point, the RELIABILITY COORDINATOR shall begin the process of curtailing INTERCHANGE TRANSACTIONS as calculated in Section 7.2.2 over the CONSTRAINED FACILITIES using Firm Point-to-Point Transmission Service until the OPERATING SECURITY LIMIT violation has been mitigated. The RELIABILITY COORDINATOR shall assist the Transmission Provider in curtailing Transmission Service to Network Integration Transmission Service customers and Native Load if such curtailments are required by the TRANSMISSION PROVIDERS’ tariff. Available re-dispatch options will continue to be implemented.

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8. **TLR Level 6 – Emergency Procedures**

8.1. **Circumstances:**

- One or more Transmission Facilities are above their OPERATING SECURITY LIMIT.
- One or more Transmission Facilities will exceed their OPERATING SECURITY LIMIT upon the removal from service of a generating unit or another transmission facility.

8.2. **Implementing emergency procedures.** If the transmission loading condition is deemed critical to bulk system reliability by a RELIABILITY COORDINATOR, the RELIABILITY COORDINATOR has the authority to immediately direct the CONTROL AREAS in his RELIABILITY AREA to re-dispatch generation, or reconfigure transmission, or reduce load to mitigate the critical condition until INTERCHANGE TRANSACTIONS can be reduced utilizing the TLR Procedures or other procedures to return the system to a secure state. All CONTROL AREAS shall comply with all requests from their RELIABILITY COORDINATOR.

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9. **TLR Level 0 – TLR concluded**

9.1. **Interchange TRANSACTION restoration and notification procedures.** The RELIABILITY COORDINATOR initiating the TLR Procedure shall notify all RELIABILITY COORDINATORS within the INTERCONNECTION via the RCIS when the OPERATING SECURITY LIMIT violations are mitigated and the system is in a “normal” state, allowing INTERCHANGE TRANSACTIONS to be reestablished at his discretion. Those with the highest transmission priorities shall be reestablished first if possible.

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Appendix 9C1 – Transmission Loading Relief Procedure

B. Transmission Loading Relief (TLR) Levels

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Version 2b A9C1-16 Approved by Board of Trustees: October 8, 2002
C. Interchange Transaction Curtailment Order

**Curtailment of Interchange Transactions Using Non-firm Transmission Service**

The RELIABILITY COORDINATOR will direct the curtailment of INTERCHANGE TRANSACTIONS using Non-firm TRANSMISSION SERVICE that are at or above the CURTAILMENT THRESHOLD for the following TLR Levels:

1. **TLR Level 3a.** Enable INTERCHANGE TRANSACTIONS using a higher Transmission reservation priority to be implemented, or

2. **TLR Level 3b.** Mitigate an OPERATING SECURITY LIMIT violation.

The INTERCHANGE TRANSACTION curtailment priority is determined by its TRANSMISSION SERVICE reservation over the constrained facility(ies) as shown in the box on the right.

The curtailment priority for INTERCHANGE TRANSACTIONS that do not have a Transmission Service reservation over the constrained facility(ies) is the lowest priority of the individual reserved transmission segments.

<table>
<thead>
<tr>
<th>Transmission Service Priorities</th>
</tr>
</thead>
<tbody>
<tr>
<td>Priority 0. Next-hour Market Service – NX*</td>
</tr>
<tr>
<td>Priority 1. Service over secondary receipt and delivery points – NS</td>
</tr>
<tr>
<td>Priority 2. Hourly Service – NH</td>
</tr>
<tr>
<td>Priority 3. Daily Service – ND</td>
</tr>
<tr>
<td>Priority 4. Weekly Service – NW</td>
</tr>
<tr>
<td>Priority 5. Monthly Service – NM</td>
</tr>
<tr>
<td>Priority 6. Network Integration Transmission Service from sources not designated as network resources – NN</td>
</tr>
<tr>
<td>Priority 7. Firm Point-to-Point Transmission Service – F and Network Integration Transmission Service from Designated Resources – FN</td>
</tr>
</tbody>
</table>

**Curtailment of Interchange Transactions Using Firm Transmission Service**

The RELIABILITY COORDINATOR will direct the curtailment of INTERCHANGE TRANSACTIONS using Firm TRANSMISSION SERVICE that are at or above the CURTAILMENT THRESHOLD for the following TLR Levels:

1. **TLR Level 5a.** Enable additional INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission Service to be implemented after all INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Service have been curtailed, or

2. **TLR Level 5b.** Mitigate an OPERATING SECURITY LIMIT violation that remains after all INTERCHANGE TRANSACTIONS using Non-firm Transmission Service has been curtailed under TLR Level 3b, and following attempts to reconfigure transmission under TLR Level 4.
D. Transaction Management and Curtailment Process

This flowchart depicts an overview of the Transaction Management and Curtailment process. Detailed decisions are not shown.
E. Principles for Mitigating Constraints On and Off the Contract Path

Introduction

Reserving transmission service for an INTERCHANGE TRANSACTION along a “contract path” may not reflect the actual distribution of the power flows over the transmission network from generation source to load sink. INTERCHANGE TRANSACTIONS arranged over a contract path may, therefore, overload transmission elements on other electrically parallel paths. The RELIABILITY COORDINATORS must agree on how the NERC Transmission Loading Relief Procedure will handle these INTERCHANGE TRANSACTIONS to, first, ensure the operational security of the INTERCONNECTION and, second, respect the obligations of the TRANSMISSION PROVIDERS’ tariffs.

The curtailment priority of an INTERCHANGE TRANSACTION depends on whether the CONSTRAINED FACILITY is on or off the contract path, and, if on the contract path, the Transmission Service of the link with the CONSTRAINED FACILITY.

The RELIABILITY COORDINATOR must also consider 1) the tariff obligations of the Transmission Provider with the CONSTRAINED FACILITY, 2) the Transmission Customer’s re-dispatch or other congestion management arrangements, and 3) arrangements among the TRANSMISSION PROVIDERS for handling certain CONSTRAINTS. Refer to examples beginning on page A9C1-21.

Principles for Constraints ON the Contract Path

Principle 1. If the transmission link with the CONSTRAINED FACILITY is Non-firm Point-to-Point Transmission Service, the entire INTERCHANGE TRANSACTION is considered non-firm, even if other links in the contract path are firm. When the CONSTRAINED FACILITY is on the contract path, the INTERCHANGE TRANSACTION takes on the transmission service priority of the Transmission Service link with the CONSTRAINED FACILITY regardless of the Transmission Service priority on the other links along the contract path.

Discussion. The TRANSMISSION PROVIDER simply has to call its RELIABILITY COORDINATOR, request the TLR Procedure be initiated, and allow the curtailments of all INTERCHANGE TRANSACTIONS that are at or above the CURTAILMENT THRESHOLD to progress until the relief is realized. Firm Point-to-Point Transmission Service links elsewhere in the contract path do not obligate TRANSMISSION PROVIDERS providing Non-firm Point-to-Point Transmission Service to treat the transaction as firm. For curtailment purposes, the INTERCHANGE TRANSACTION’s priority will be the priority of the TRANSMISSION SERVICE link with the CONSTRAINED FACILITY. (See Principle #2 below.)

Principle 2. If the transmission link with the CONSTRAINED FACILITY is Firm Point-to-Point Transmission Service, the entire INTERCHANGE TRANSACTION is considered firm, even if other links in the contract path are non-firm.

Discussion. The curtailment priority of an INTERCHANGE TRANSACTION on a contract path link is not affected by the transmission service priorities arranged with other links on the contract path. If the CONSTRAINED FACILITY is on a Firm Point-to-Point Transmission Service contract path link, then the curtailment priority of the INTERCHANGE TRANSACTION is considered firm regardless of the transmission service arrangements elsewhere on the contract path. If the TRANSMISSION PROVIDER provides its services
under the FERC pro forma tariff, it may also be obligated to offer its Transmission Customer alternate receipt and delivery points, thus allowing the Customer to curtail its Transmission Service over the CONSTRAINED FACILITIES.

**For Constraints OFF the Contract Path**

**Principle 3.** If any of the transmission links on the contract path are Non-firm Point-to-Point Transmission Service, the INTERCHANGE TRANSACTION is considered non-firm by the system with the CONSTRAINED FACILITY that is not on the contract path, and takes on the lowest transmission service priority of all TRANSMISSION SERVICE links along the contract path.

**Discussion.** An INTERCHANGE TRANSACTION arranged over a contract path where one or more individual links consist of Non-firm Point-to-Point Transmission Service is considered to be a non-firm INTERCHANGE TRANSACTION for CONSTRAINED FACILITIES off the contract path. Sufficient INTERCHANGE TRANSACTIONS that are at or above the CURTAILMENT THRESHOLD will be curtailed before any INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission Service are curtailed. The priority level for curtailment purposes will be the lowest level of transmission service arranged for on the contract path.

**Principle 4.** If all of the transmission links on the contract path with the CONSTRAINED FACILITY are Firm Point-to-Point Transmission Service, then the INTERCHANGE TRANSACTION is considered firm and will not be curtailed to relieve a CONSTRAINT off the contract path until all non-firm INTERCHANGE TRANSACTIONS that are at or above the CURTAILMENT THRESHOLD have been curtailed.

**Discussion.** If the entire contract path is Firm Point-to-Point Transmission Service, then the TLR procedure will treat the INTERCHANGE TRANSACTION as firm even for CONSTRAINTS off the contract path and will not curtail that INTERCHANGE TRANSACTION until all non-firm INTERCHANGE TRANSACTIONS that are at or above the CURTAILMENT THRESHOLD have been curtailed. However, TRANSMISSION PROVIDERS off the contract path are not obligated to reconfigure their transmission system or provide other congestion management procedures unless special arrangements are in place. Because the INTERCHANGE TRANSACTION is considered firm “everywhere,” the RELIABILITY COORDINATOR may attempt to arrange for TRANSMISSION PROVIDERS or CONTROL AREAS to reconfigure transmission or provide other congestion management options, even if they are off the contract path, to try to avoid curtailling the INTERCHANGE TRANSACTION that is using the Firm Point-to-Point Transmission Service.
Examples

This section explains, by example, the obligations of the TRANSMISSION PROVIDERS on and off the contract path when calling for Transmission Loading Relief. (References to Principles refer to Section E, “Principles for Mitigating Constraints On and Off the Contract Path,” on the preceding pages.)

When Reallocating or curtailing INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission Service under TLR Level 5a or 5b, the TRANSMISSION PROVIDER may be obligated to perform comparable curtailments of its TRANSMISSION SERVICE to Network Integration and Native Load customers. See Section F, “Parallel Flow Calculation Procedure for Reallocating or Curtailing Firm Transmission Service”.

Scenario:
- INTERCHANGE TRANSACTION arranged from system A to system D, and assumed to be at or above the CURTAILMENT THRESHOLD
- Contract path is A-E-C-D (except as noted)
- Locations 1 and 2 denote CONSTRAINTS

Case 1: E is a non-firm Monthly path, C is non-firm Hourly; E has CONSTRAINT at #2.
- E may call RELIABILITY COORDINATOR for TLR Procedure to relieve overload at CONSTRAINT #2.
- INTERCHANGE TRANSACTION A-D may be curtailed by TLR action as though it was being served by Non-firm Monthly Point-to-Point Transmission Service, even though it was using Non-firm Hourly Point-to-Point TRANSMISSION SERVICE from C. That is, it takes on the priority of the link with the CONSTRAINED FACILITY along the contract path. (Principle 1)

Case 2: E is a non-firm hourly path, C is firm; E has CONSTRAINT at #2.
- Although C is providing Firm Service, the CONSTRAINT is not on C’s system; therefore E is not obligated to treat the Interchange Transaction as though it was being served by Firm Point-to-Point Transmission Service.
- E may call RELIABILITY COORDINATOR for TLR Procedure to relieve overload at CONSTRAINT #2.
- INTERCHANGE TRANSACTION A-D may be curtailed by TLR action as though it was being served by Non-firm Hourly Point-to-Point Transmission Service, even though it was using firm service from C. That is, when the constraint is on the contract path, the Interchange Transaction takes on the priority of the link with the CONSTRAINED FACILITY. (Principle 1)
Appendix 9C1 – Transmission Loading Relief Procedure

E. Principles for Mitigating Constraints On and Off the Contract Path

Case 3: E is a non-firm hourly path, C is firm, B has CONSTRAINT at #1.

- B may call RELIABILITY COORDINATOR for TLR Procedure to relieve overload at CONSTRAINT #1.

- INTERCHANGE TRANSACTION A-D may be curtailed by TLR action as though it was being served by Non-firm Hourly Transmission Service, even if it was using firm Transmission Service elsewhere on the path. When the constraint is off the contract path, the Interchange Transaction takes on the lowest priority reserved on the contract path. (Principle 3)

Case 4: E is a firm path; A, D, and C are Non-firm; E has CONSTRAINT at #2.

- Interchange Transaction A – D is considered Firm priority for curtailment purposes.

- E may then call RELIABILITY COORDINATOR for TLR, which would curtail all INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Transmission Service first.

- E is obligated to try to reconfigure transmission to mitigate CONSTRAINT #2 in E before E may curtail the INTERCHANGE TRANSACTION as ordered by the TLR. (Principle 2)

Case 5: The entire path (A-E-C-D) is firm; E has CONSTRAINT at #2.

- INTERCHANGE TRANSACTION A – D is considered Firm priority for curtailment purposes.

- E may call RELIABILITY COORDINATOR for TLR, which would curtail all INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Transmission Service first.

- E is obligated to curtail INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Transmission Service, and then reconfigure transmission on its system, or, if there is an agreement in place, arrange for reconfiguration or other congestion management options on another system, to mitigate CONSTRAINT #2 in E before the firm A-D transaction is curtailed. (Principle 2)

- A, C, D, may be requested by E to try to reconfigure transmission to mitigate CONSTRAINT #2 in E at E’s expense. (Principle 2)
Case 6: The entire path (A-E-C-D) is firm; B has constraint at #1.

- INTERCHANGE TRANSACTION A – D is considered Firm priority for curtailment purposes.

- B may call RELIABILITY COORDINATOR for TLR Procedure for all non-firm INTERCHANGE TRANSACTIONS that contribute to the overload at CONSTRAINT #1.

Case 7: Two A-to-D transactions using A-B-C-D and A-E-C-D; A and B are non-firm; B has constraint at #1

- B is not obligated to reconfigure transmission to mitigate CONSTRAINT at #1. (Principle 1)

- B may call for TLR Procedure to relieve overload at CONSTRAINT #1.

- If both A – D Interchange Transactions have the same TDF across Constraint #1, then they both are subject to curtailment. However, INTERCHANGE TRANSACTION A – D using the A-B-C-D path is assigned a higher priority (priority NW on B), and would not be curtailed until after the Interchange Transaction using the path A-E-C-D (priority NH on the contract path as observed by B who is off the contract path).
Appendix 9C1 – Transmission Loading Relief Procedure

F. Parallel Flow Calculation Procedure for Reallocating or Curtailing Firm Transmission Service

[See also “Parallel Flow Calculation Procedure Reference Document”]

Introduction

The provision of Point-to-Point (PTP) transmission service, Network Integration (NI) transmission service and service to Native Load (NL) results in parallel flows on the transmission network of other TRANSMISSION PROVIDERS. When a transmission facility becomes constrained, NERC Policy 9C, Appendix 9C1, calls for curtailment of INTERCHANGE TRANSACTIONS to allow INTERCHANGE TRANSACTIONS of higher priority to be scheduled (REALLOCATION) or to provide transmission loading relief (CURTAILMENT). An INTERCHANGE TRANSACTION is considered for REALLOCATION or CURTAILMENT if its TRANSFER DISTRIBUTION FACTOR (TDF) exceeds the TLR CURTAILMENT THRESHOLD.

In compliance with the Pro Forma tariffs filed with FERC by TRANSMISSION PROVIDERS, INTERCHANGE TRANSACTIONS using Non-firm PTP transmission service are curtailed first (TLR Level 3a and 3b), followed by transmission reconfiguration (TLR Level 4), and then the curtailment of INTERCHANGE TRANSACTIONS using Firm PTP transmission service, NI transmission service and service to NL (TLR Level 5a and 5b). The NERC TLR Procedure requires that the curtailment of Firm PTP transmission service be accompanied by the comparable curtailment of NI transmission service and service to NL to the degree that these three transmission services contribute to the CONSTRAINT.

Basic Principles

A methodology, called the Per Generator Method Without Counter Flow, or simply the Per Generator Method, has been programmed into the INTERCHANGE DISTRIBUTION CALCULATOR (IDC) to calculate the portion of parallel flows on any CONSTRAINED FACILITY due to service to NL of each CONTROL AREA (CA). The basic principles followed to assure comparable REALLOCATION or CURTAILMENT of firm transmission services are:

1. All firm transmission services (i.e. PTP, NI and service to NL) that contribute to the flow on any CONSTRAINED FACILITY by an amount greater than or equal to the CURTAILMENT THRESHOLD must be curtailed on a pro rata basis.
2. For Firm PTP transmission services, the TRANSFER DISTRIBUTION FACTORS (TDFs) must be greater than or equal to the CURTAILMENT THRESHOLD.
3. For NI transmission service and service to NL, the generator-to-load distribution factors (GLDFs) must be greater than or equal to the CURTAILMENT THRESHOLD. The GLDF on a specific CONSTRAINED FACILITY for a given generator within a CONTROL AREA is defined as the generator’s contribution to the flow on that flowgate when supplying the load of that CONTROL AREA.
4. The Per Generator Method assigns the amount of CONSTRAINED FACILITY relief that must be achieved by each CONTROL AREA’s NI transmission service or service to NL. It does not specify how the reduction will be achieved.
5. The Per Generator Method places an obligation on all CONTROL AREAS in the Eastern Interconnection to achieve the amount of CONSTRAINED FACILITY relief assigned to them.
6. The implementation of the Per Generator Method must be based on transmission and generation information that is readily available.
### Calculation Method

The calculation of the flow on a **CONTRAINE** facility due to NI transmission service or service to NL is based on the Generation Shift Factors (GSFs) of a **CONTROL AREA**’s assigned generation and the Load Shift Factors (LSFs) of its native load, relative to the system swing bus. The GSFs are calculated from a single bus location in the IDC model. The LSFs are defined as a general scaling of the native load within each **CONTROL AREA**. The Generator to Load Distribution Factor (GLDF) is calculated as the GSF minus the LSF. The IDC reports all generators assigned to native load for which the GLDF is greater than or equal to the **CURTAILMENT THRESHOLD**.

The “**Parallel Flow Calculation Procedure Reference Document**” provides additional information about the criteria used to include generators in the IDC calculation process.

### Example of Results of Calculation Method

An example of the output of the IDC calculation of curtailment of firm transmission service is provided below for the specific **CONTRAINE** facility identified in the Book of Flowgates as Flowgate 1368. In this example, a total Firm PTP contribution to the **CONTRAINE** facility, as calculated by the IDC, is assumed to be 21.8 MW.

The table below presents a summary of each **CONTROL AREA**’s responsibility to provide relief to the **CONTRAINE** facility due to its NI transmission service and service to NL contribution to the **CONTRAINE** facility. In this example, **CONTROL AREA LAGN** would be requested to curtail 17.3 MW of its total of 401.1 MW of flow contribution on the **CONTRAINE** facility. See the “**Parallel Flow Calculation Procedure Reference Document**” for additional details regarding the information illustrated in the table (e.g. Scaled P Max and Flowgate NNL MW).

In summary, **INTERCHANGE TRANSACTIONS** would be curtailed by a total of 21.8 MW and **NI transmission service** and service to NL would be curtailed by a total of 178.2 MW by the five **CONTROL AREAS** identified in the table. These curtailments would provide a total of 200.0 MW of relief to the **CONTRAINE** **FACILITY**.

<table>
<thead>
<tr>
<th>Sink RA</th>
<th>Service Point</th>
<th>Scaled P Max</th>
<th>Flowgate NNL MW</th>
<th>Current NNL Relief</th>
<th>NNL Responsibility Acknowledgement</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Inc/Dec</td>
</tr>
<tr>
<td>EES</td>
<td>EES</td>
<td>8429.7</td>
<td>2991.4</td>
<td>0.0</td>
<td>128.9</td>
</tr>
<tr>
<td>EES</td>
<td>LAGN</td>
<td>1514.0</td>
<td>718.6</td>
<td>0.0</td>
<td>31.0</td>
</tr>
<tr>
<td>SOCO</td>
<td>SOCO</td>
<td>5089.2</td>
<td>401.1</td>
<td>0.0</td>
<td>17.3</td>
</tr>
<tr>
<td>SWPP</td>
<td>CLEC</td>
<td>235.7</td>
<td>18.0</td>
<td>0.0</td>
<td>0.8</td>
</tr>
<tr>
<td>SWPP</td>
<td>LEPA</td>
<td>22.8</td>
<td>4.1</td>
<td>0.0</td>
<td>0.2</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td><strong>15291.4</strong></td>
<td><strong>4133.2</strong></td>
<td><strong>0.0</strong></td>
<td><strong>178.2</strong></td>
</tr>
</tbody>
</table>
Appendix 9C1 – Transmission Loading Relief Procedure

G. Transaction Curtailment Formula

Example
This example is based on the premise that a transaction should be curtailed in proportion to its TDF on the CONSTRAINTS. Its effect on the interface is a combination of its size in MW and its effect based on its distribution factor.

<table>
<thead>
<tr>
<th>Column</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Initial Transaction</td>
<td>INTERCHANGE TRANSACTION before the TLR Procedure is implemented.</td>
</tr>
<tr>
<td>2. Distribution Factor</td>
<td>Proportional effect of the Transaction over the constrained interface due to the physical arrangement and impedance of the transmission system.</td>
</tr>
<tr>
<td>3. Impact on the Interface</td>
<td>Result of multiplying the Transaction MW by the distribution factor. This yields the MW that flow through the constrained interface from the Transaction. Performing this calculation for each Transaction yields the total flow through the constrained interface from all the INTERCHANGE TRANSACTIONS. In this case, 760 MW.</td>
</tr>
<tr>
<td>5. Weighted Maximum Interface Reduction</td>
<td>Multiplying the Impact on the Interface from each Transaction by its Impact Weighting Factor yields a new proportion that is a combination of the MW Impact on the Interface and the Distribution Factor.</td>
</tr>
<tr>
<td>6. Interface Reduction</td>
<td>Multiplying the amount we need to reduce the flow over the constrained interface (280 MW) by the normalization of the Weighted Maximum Interface Reduction yields the actual MW reduction that each Transaction must contribute to achieve the total reduction.</td>
</tr>
<tr>
<td>7. Transaction Reduction</td>
<td>Now we have to divide by the Distribution Factor to see how much the Transaction must be reduced to yield the result we calculated in Column 7. Note that the reductions for the first two INTERCHANGE TRANSACTIONS (A-D (1) and A-D (2) are in proportion to their size since their distribution factors are equal.</td>
</tr>
<tr>
<td>9. Adjusted Impact on Interface</td>
<td>A check to ensure the new constrained interface MW flow has been reduced to the target amount.</td>
</tr>
</tbody>
</table>
### Allocation based on Weighted Impact

<table>
<thead>
<tr>
<th>Transaction ID</th>
<th>Initial Transaction</th>
<th>Distribution Factor</th>
<th>(1)(\times)(2) Impact On Interface</th>
<th>(2)/(2TOT) Impact weighting factor</th>
<th>(3)/(4) Weighted Max Interface Reduction</th>
<th>(5)/(6) (Relief Requested)/(5 Tot) Interface Reduction</th>
<th>(6)/(2) Transaction Reduction</th>
<th>(1)-(7) New Transaction Amount</th>
<th>(8)/(2) Adjusted Impact On Interface</th>
</tr>
</thead>
<tbody>
<tr>
<td>A-D(1)</td>
<td>800</td>
<td>0.6</td>
<td>480</td>
<td>0.34</td>
<td>164.57</td>
<td>209.73</td>
<td>349.54</td>
<td>450.46</td>
<td>270.27</td>
</tr>
<tr>
<td>A-D(2)</td>
<td>200</td>
<td>0.6</td>
<td>120</td>
<td>0.34</td>
<td>41.14</td>
<td>52.43</td>
<td>87.39</td>
<td>112.61</td>
<td>67.57</td>
</tr>
<tr>
<td>B-D</td>
<td>800</td>
<td>0.15</td>
<td>120</td>
<td>0.09</td>
<td>10.29</td>
<td>13.11</td>
<td>87.39</td>
<td>712.61</td>
<td>106.89</td>
</tr>
<tr>
<td>C-D</td>
<td>100</td>
<td>0.2</td>
<td>20</td>
<td>0.11</td>
<td>2.29</td>
<td>2.91</td>
<td>14.56</td>
<td>85.44</td>
<td>17.09</td>
</tr>
<tr>
<td>E-B</td>
<td>100</td>
<td>0.05</td>
<td>5</td>
<td>0.03</td>
<td>0.14</td>
<td>0.18</td>
<td>3.64</td>
<td>96.36</td>
<td>4.82</td>
</tr>
<tr>
<td>F-B</td>
<td>100</td>
<td>0.15</td>
<td>15</td>
<td>0.09</td>
<td>1.29</td>
<td>1.64</td>
<td>10.92</td>
<td>89.08</td>
<td>13.36</td>
</tr>
<tr>
<td><strong>Example 1</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>2100</strong></td>
<td>1.75</td>
<td><strong>760</strong></td>
<td><strong>219.71</strong></td>
<td><strong>280.00</strong></td>
<td><strong>553.45</strong></td>
<td><strong>1546.55</strong></td>
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<td></td>
</tr>
<tr>
<td>A-D(1)</td>
<td>1000</td>
<td>0.6</td>
<td>600</td>
<td>0.52</td>
<td>313.04</td>
<td>262.16</td>
<td>436.93</td>
<td>563.07</td>
<td>337.84</td>
</tr>
<tr>
<td>B-D</td>
<td>800</td>
<td>0.15</td>
<td>120</td>
<td>0.13</td>
<td>15.65</td>
<td>13.11</td>
<td>87.39</td>
<td>712.61</td>
<td>106.89</td>
</tr>
<tr>
<td>C-D</td>
<td>100</td>
<td>0.2</td>
<td>20</td>
<td>0.17</td>
<td>3.48</td>
<td>2.91</td>
<td>14.56</td>
<td>85.44</td>
<td>17.09</td>
</tr>
<tr>
<td>E-B</td>
<td>100</td>
<td>0.05</td>
<td>5</td>
<td>0.04</td>
<td>0.22</td>
<td>0.18</td>
<td>3.64</td>
<td>96.36</td>
<td>4.82</td>
</tr>
<tr>
<td>F-B</td>
<td>100</td>
<td>0.15</td>
<td>15</td>
<td>0.13</td>
<td>1.96</td>
<td>1.64</td>
<td>10.92</td>
<td>89.08</td>
<td>13.36</td>
</tr>
<tr>
<td><strong>Example 2</strong></td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>2100</strong></td>
<td>1.15</td>
<td><strong>760</strong></td>
<td><strong>334.35</strong></td>
<td><strong>280.00</strong></td>
<td><strong>553.45</strong></td>
<td><strong>1546.55</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>A-D(1A)</td>
<td>200</td>
<td>0.6</td>
<td>120</td>
<td>0.17</td>
<td>20.28</td>
<td>52.43</td>
<td>87.39</td>
<td>112.61</td>
<td>67.57</td>
</tr>
<tr>
<td>A-D(1B)</td>
<td>200</td>
<td>0.6</td>
<td>120</td>
<td>0.17</td>
<td>20.28</td>
<td>52.43</td>
<td>87.39</td>
<td>112.61</td>
<td>67.57</td>
</tr>
<tr>
<td>A-D(1C)</td>
<td>200</td>
<td>0.6</td>
<td>120</td>
<td>0.17</td>
<td>20.28</td>
<td>52.43</td>
<td>87.39</td>
<td>112.61</td>
<td>67.57</td>
</tr>
<tr>
<td>A-D(1D)</td>
<td>200</td>
<td>0.6</td>
<td>120</td>
<td>0.17</td>
<td>20.28</td>
<td>52.43</td>
<td>87.39</td>
<td>112.61</td>
<td>67.57</td>
</tr>
<tr>
<td>A-D(2)</td>
<td>200</td>
<td>0.6</td>
<td>120</td>
<td>0.17</td>
<td>20.28</td>
<td>52.43</td>
<td>87.39</td>
<td>112.61</td>
<td>67.57</td>
</tr>
<tr>
<td>B-D</td>
<td>800</td>
<td>0.15</td>
<td>120</td>
<td>0.04</td>
<td>5.07</td>
<td>13.11</td>
<td>87.39</td>
<td>712.61</td>
<td>106.89</td>
</tr>
<tr>
<td>C-D</td>
<td>100</td>
<td>0.2</td>
<td>20</td>
<td>0.06</td>
<td>1.13</td>
<td>2.91</td>
<td>14.56</td>
<td>85.44</td>
<td>17.09</td>
</tr>
<tr>
<td>E-B</td>
<td>100</td>
<td>0.05</td>
<td>5</td>
<td>0.01</td>
<td>0.07</td>
<td>0.18</td>
<td>3.64</td>
<td>96.36</td>
<td>4.82</td>
</tr>
<tr>
<td>F-B</td>
<td>100</td>
<td>0.15</td>
<td>15</td>
<td>0.04</td>
<td>0.63</td>
<td>1.64</td>
<td>10.92</td>
<td>89.08</td>
<td>13.36</td>
</tr>
<tr>
<td><strong>Example 3</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>2100</strong></td>
<td>3.55</td>
<td><strong>760</strong></td>
<td><strong>108.31</strong></td>
<td><strong>280.00</strong></td>
<td><strong>553.45</strong></td>
<td><strong>1546.55</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Diagram:**

- A: 800 (450)
- B: 200 (112)
- C: 100 (85)
- D: 800 (713)
- E: 100 (96)
- F: 100 (89)
## H. NERC Transmission Loading Relief Procedure Log

### INITIAL CONDITIONS

<table>
<thead>
<tr>
<th>Limiting Flowgate (LIMIT)</th>
<th>Rating</th>
<th>Contingent Flowgate (CONT.)</th>
<th>ODF</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

### TLR Levels

<table>
<thead>
<tr>
<th>No.</th>
<th>Time</th>
<th>Priority</th>
<th>TLR 3,5 No. TX Curtail</th>
<th>TLR 3,5 MW Curtail</th>
<th>MW Flow</th>
<th>TLR ACTIONS</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>COMMENTS ABOUT ACTIONS</td>
</tr>
</tbody>
</table>

- TLR Levels Priorities:
  - NX: Next Hour Market Service
  - NS: Service over secondary receipt and delivery points
  - NH: Hourly Service
  - ND: Daily Service
  - NW: Weekly Service
  - NM: Monthly Service
  - NN: Non-firm imports for native load and network customers from non-designated network resources
  - F: Firm Service

This report log is being automated and will be revised.

Version 2b  
A9C1-28  
Approved by Board of Trustees:  
October 8, 2002
Appendix 9C1B – Interchange Transaction Reallocation During TLR Levels 3a and 5a

Appendix Subsections
A. Basic Principles
B. Communication and Timing Requirements
C. How the IDC Handles Reallocation
Attachment A – Summary of IDC Features that Support Transaction Reloading/Reallocation
Attachment B – Timing Requirements

Introduction
This Appendix provides the details for implementing TLR Levels 3a and 5a, both of which provide a means for reallocation of Transmission Service.

TLR Level 3a accomplishes Reallocation by curtailing INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Transmission Service to allow INTERCHANGE TRANSACTIONS using higher priority Non-firm or Firm Point-to-Point Transmission Service to start. (See Appendix 9C1, “TLR Procedure – Eastern Interconnection,” Section B.3, “TLR Level 3a.”) When a NERC TLR Level 3a is in effect, RELIABILITY COORDINATORS shall reallocate INTERCHANGE TRANSACTIONS according to the TRANSACTIONS’ transmission service priorities. Reallocation also includes the orderly reloading of TRANSACTIONS by priority when conditions permit curtailed TRANSACTIONS to be reinstated.

TLR Level 5a accomplishes Reallocation by curtailing INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission Service on a pro-rata basis to allow new INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission Service to begin, also on a pro-rata basis. (See Appendix 9C1, “TLR Procedure – Easton Interconnection,” Section B.6, “TLR Level 5a.”)

A. Basic Principles
The basic principles for TRANSACTION REALLOCATION are built upon the premises of FERC Order 888, NERC Operating Policies and current business practices. Specifically, the key principles are:

1. Transaction REALLOCATION will normally only involve curtailments of INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Transmission Service (TLR 3a). However, REALLOCATION may be used during TLR 5a to allow the implementation of additional INTERCHANGE TRANSACTIONS using Firm Transmission Service on a pro-rata basis.

2. Only those INTERCHANGE TRANSACTIONS at or above the CURTAILMENT THRESHOLD for which a TLR 2 or higher is called are affected by the Reallocation procedure.

3. INTERCHANGE TRANSACTIONS with higher transmission service priority will displace INTERCHANGE TRANSACTIONS using lower priority transmission service.

4. INTERCHANGE TRANSACTIONS using Non-firm Transmission Service will not be curtailed to allow the start or increase of another transaction having the same Non-Firm Transmission Service priority (marginal “bucket”).

5. Reloading of curtailed INTERCHANGE TRANSACTIONS will precede starting of new or increased INTERCHANGE TRANSACTIONS.

The Curtailment Threshold is currently set at 5%.
6. **INTERCHANGE TRANSACTIONS** whose tags were submitted to the Tag Authority prior to the TLR 2 or 3a being called, but were subsequently held from starting because they failed to meet the Approved-Tag Submission Deadline for Reallocation (*see Section C, “Communications and Timing Requirements”), would be considered to have been curtailed and thus would be eligible for reload at the same time as the curtailed **INTERCHANGE TRANSACTION**.

7. Eligible **TRANSACTIONS** will be reloaded or started on a pro-rata basis.

8. **INTERCHANGE TRANSACTIONS** whose tags meet the Approved-Tag Submission Deadline for Reallocation (*see Section C, “Communications and Timing Requirements”) will be considered for reallocation for the upcoming hour. (However, **INTERCHANGE TRANSACTIONS** using Firm Point-to-Point Transmission Service will be allowed to start as scheduled.) **INTERCHANGE TRANSACTIONS** whose tags are submitted to the Interchange Distribution Calculator after the Approved-Tag Submission Deadline for Reallocation will be considered for Reallocation the following hour. This applies to **INTERCHANGE TRANSACTIONS** using either Non-firm Point-to-Point Transmission Service and Firm Point-to-Point Transmission Service. If an **INTERCHANGE TRANSACTION** using Firm Interchange Transaction is submitted after the Approved-Tag Submission Deadline and after the TLR is declared, that Transaction will be held and then allowed to start in the upcoming hour.

It should be noted that calling a TLR 3a does not necessarily mean that **INTERCHANGE TRANSACTIONS** using Non-firm Transmission Service will always be curtailed the next hour. However, TLR Levels 3a and 5a trigger the Approved-Tag Submission Deadline for Reallocation requirements and allow for a coordinated assessment of all **INTERCHANGE TRANSACTIONS** tagged to start the upcoming hour.
B. Communication and Timing requirements

When in a TLR 3a or 5a, the following timeline is required to support REALLOCATION. See Figures 2 and 3 for a depiction of the Reallocation Time Line.

**Time Convention.** In this document, the beginning of the current hour is 0000. The beginning of the next hour is 01:00 (see Figure 1 at right).

**Approved-Tag Submission Deadline for Reallocation.** Approved Tags for INTERCHANGE TRANSACTIONS at or above the CURTAILMENT THRESHOLD must be submitted to the Interchange Distribution Calculator by 00:25 to be considered for Reallocation at 01:00. (See Figure 1 at the right). (However, INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission Service will be allowed to start as scheduled.) Tags submitted to the Interchange Distribution Calculator beyond these deadlines (for both Firm and Non-firm Point-to-Point Transmission Service) will not be allowed to start or increase at 01:00 but will be considered for REALLOCATION at 02:00. As soon as the TLR level is reduced to 1 or 0, the Approved-Tag Submission Deadline for Reallocation is no longer in effect.

**Off-hour Transactions.** Interchange Transactions with a Start Time other than xx:00 will be considered for Reallocation at xx+1:00. For example, an Interchange Transaction with a start time of 01:05 and whose Tag was submitted at 00:15 will be considered for Reallocation at 02:00.

**Tag Evaluation Period.** Tags will be evaluated by the appropriate CONTROL AREAS and TRANSMISSION PROVIDERS. The CONTROL AREA and TRANSMISSION PROVIDER are expected to communicate approval or rejection (via the Tag Approval) by 00:25.

**Collective Scheduling Assessment Period.** The initiating RELIABILITY COORDINATOR (the one who called and still has a TLR 3a or 5a in effect) shall at this time (00:25) run the IDC to obtain a three-part list of INTERCHANGE TRANSACTIONS including their transaction status:

1. INTERCHANGE TRANSACTIONS that may start, increase, or reload will have a status of PROCEED,

2. INTERCHANGE TRANSACTIONS that must be curtailed or INTERCHANGE TRANSACTIONS whose tags were submitted prior to the TLR 2 or higher being declared but were not permitted to start or increase will have a status of CURTAILED, and

3. INTERCHANGE TRANSACTIONS that are entered into the IDC after 00:25 will have a status of HOLD\(^1\) and be considered for REALLOCATION at 02:00. Also, INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Transmission Service submitted to the Tag Authority after TLR 2 or higher was declared (“post-tagged”) but have not been allowed to start will retain the HOLD status until given

---

\(^1\) The use of PROCEED, CURTAILED, and HOLD refer to an Interchange Transaction status in the IDC, not the E-tag status.
permission to PROCEED or E-Tag expires. (Note: TLR Level 2 does not hold INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission Service).

Figure 2 - Reallocation timing for TLR 3a called at 00:08.
The initiating RELIABILITY COORDINATOR shall communicate the list to the appropriate sink RELIABILITY COORDINATORS via the IDC, who shall in turn communicate the list to the SINK CONTROL AREAS at 00:30 for appropriate actions to implement INTERCHANGE TRANSACTIONS (CURTAIL, PROCEED or HOLD). The IDC will prompt the initiating RELIABILITY COORDINATOR to input the necessary information (i.e., maximum flowgate loading and curtailment requirement) into the IDC by 00:25.

Subsequent required reports before 01:00 will allow the RELIABILITY COORDINATORS to include those INTERCHANGE TRANSACTIONS whose tags were submitted to the IDC after the Approved-Tag Submission Time for Reallocation and were given the HOLD status (not permitted to PROCEED). Transactions at or above the Curtailment Threshold that are not indicated as “PROCEED” on Reload/Reallocation Report will not be permitted to start or increase the next hour.

Note that TLR 2 does not initiate the Approved-Tag Submission Deadline for Reallocation, but a TLR3a or 5a does. It is, however, important to recognize the time when a TLR 2 is called, where applicable, to determine the status of a held transaction – “CURTAILED” if tagged before the TLR was called but “HOLD” if tagged after the TLR was called.

In running the IDC, the RELIABILITY COORDINATOR will have an option to specify the maximum loading of the CONSTRAINED FACILITY by all INTERCHANGE TRANSACTIONS using Point-to-Point Transmission Service. This allows the RELIABILITY COORDINATOR to take into consideration OPERATING SECURITY LIMITS and changes in TRANSACTIONS using other than point-to-point service taken under the OATT. This option is needed to avoid loading the CONSTRAINED FACILITY to its limit with known INTERCHANGE TRANSACTIONS while other factors push the facility into OPERATING SECURITY LIMIT violation and hence triggering the declaration of a TLR 3b or 5b.

Notification of INTERCHANGE TRANSACTION status will go from the IDC to the RELIABILITY COORDINATORS via an IDC Report. Information will be communicated from the RELIABILITY COORDINATORS to the CONTROL AREAS and TRANSMISSION PROVIDERS by present methods. Coordination of INTERCHANGE TRANSACTION changes including new INTERCHANGE TRANSACTIONS will be implemented according to existing practices depicted in Policy 3.
Additional reporting and communications details on information posted from the IDC to the NERC TLR site are contained in Attachment A.

**Customer Preferences on Timing to Call TLR 3a or 5a.** A RELIABILITY COORDINATOR will call a TLR 2 or 3a whenever he deems necessary to indicate that a transmission facility is approaching its OPERATING SECURITY LIMIT. It is envisioned, though not required, that a TLR 2 or 3a is preceded by a period of a TLR 1 declaration, hence Transmission Customers should normally have advance notice of a potential CONSTRAINT. RELIABILITY COORDINATORS should leave a TLR 2 and call a TLR 3a as soon as possible (but no later than 30 minutes) to initiate the Approved-Tag Submission Deadline and start reallocating TRANSACTIONS. Nevertheless, recognizing the Approved-Tag Submission Deadline for Reallocation for REALLOCATION, from a Transmission Customer perspective, it is preferable that the RELIABILITY COORDINATOR call TLR 3a within a certain time period to allow for tag preparation and submission.

For example, a TLR 3a initiated during the period 01:00 to 01:25 would allow the Purchasing-Selling Entity to submit a Tag for entry into the Interchange Distribution Calculator by the Approved-Tag Submission Deadline for reallocation at 02:00 (see Figure 4 at right). However, the preferred time period to declare a TLR 3a or 5a would be 00:40 (when tags for Next Hour Market have been submitted) and 01:15. This will allow the Transmission Customers a range of 15 to 35 minutes to prepare and submit tags. (Note: In this situation, the RELIABILITY COORDINATOR would need to reissue the TLR 3a at 01:00.)

It must be emphasized that the preferred time period is not a requirement, and should not in any way impede a RELIABILITY COORDINATOR’S ability to declare a TLR 3a, 3b, 4, 5a, or 5b whenever the need arises.

![Figure 4 - "Ideal" time for issuing TLR 3a for Reallocation at 02:00.](image-url)
C. How the IDC Handles Reallocation

The Interchange Distribution Calculator algorithms reflect the reallocation and reloading principles in this Appendix, as well as the reporting requirements, and status display. The IDC will obtain the Tag Submittal Time from the Tag Authority, and post the Reloading/ Reallocation information to the NERC TLR site.

A summary of IDC features that support the reallocation process is provided in Attachment A. Details on the interface and display features are provided in Attachment B.
Attachment A – Summary of IDC Features that Support Transaction Reloading/Reallocation

The following is a summary of IDC features and E-Tag interface that support Reloading/Reallocation:

**Information posted from IDC to NERC TLR site.**
1. Restricted directions (all source/sink combinations that impact a CONSTRAINED FACILITY(IES) with TLR 2 or higher) will be posted to the NERC TLR site and updated as necessary.

2. TLR CONSTRAINED FACILITY status and TRANSFER DISTRIBUTION FACTORS will continue to be posted to NERC TLR site.

3. Lowest priority of INTERCHANGE TRANSACTIONS (marginal “bucket”) to be Reloaded/Reallocated next-hour on each TLR CONSTRAINED FACILITY will be posted on NERC TLR site. This will provide an indication to the market of priority of INTERCHANGE TRANSACTIONS that may be Reloaded/Reallocated the following hours.

**IDC Logic, IDC Report, and Timing**
1. The RELIABILITY COORDINATOR will run the IDC the Reloading/Reallocation report at approximately 00:26. The IDC will prompt the RELIABILITY COORDINATOR to enter a maximum loading value. The IDC will alarm if the RELIABILITY COORDINATOR doesn’t enter this value and issue a report by 00:30 or change from TLR 3a Level. The Report will be distributed to CONTROL AREAS at 00:30. This process repeats every hour as long as the Approved-Tag Submission Deadline for Reallocation is in effect (or until the TLR level is reduced to 1 or 0).

2. For INTERCHANGE TRANSACTIONS in the restricted directions, tags must be submitted to the Interchange Distribution Calculator by the Approved-Tag Submission Deadline for Reallocation to be considered for REALLOCATION next-hour. The time stamp by the Tag Authority is regarded the official tag submission time.

3. Tags submitted to Interchange Distribution Calculator after the Approved-Tag Submission Deadline for Reallocation will not be allowed to start or increase but will be considered for Reallocation the next hour.

4. INTERCHANGE TRANSACTIONS in restricted directions that are not indicated as “PROCEED” on the Reload/Reallocation Report will not be permitted to start or increase next hour.

**Reloading/Reallocation Transaction Status**
Reloading/Reallocation status will be determined by the IDC for all INTERCHANGE TRANSACTIONS. The Reloading/Reallocation status of each INTERCHANGE TRANSACTION will be listed on IDC reports and NERC TLR site as appropriate. An INTERCHANGE TRANSACTION is considered to be in a restricted direction if it is at or above the Curtailment Threshold. INTERCHANGE TRANSACTIONS below the Curtailment Threshold are unrestricted and free to flow subject to all applicable Policy and tariff rules.

1. **HOLD.** Permission has not been given for INTERCHANGE TRANSACTION to start or increase and is waiting for the next Reloading/Reallocation evaluation for which it is a candidate. INTERCHANGE TRANSACTIONS with E-tags submitted to the Tag Authority prior to TLR 2 or higher being declared (pre-tagged) will change to CURTAILED Status upon evaluation that does not permit them to start or...
increase. Transactions with E-tags submitted to Tag Authority after TLR 2 or higher was declared (post-tagged) will retain HOLD Status until given permission to proceed or E-Tag expires.

2. **CURTAILED.** Transactions for which E-Tags were submitted to Tag Authority prior to TLR 2 or higher being declared (pre-tagged) and ordered to be curtailed totally, curtailed partially, not permitted to start, or not permitted to increase. INTERCHANGE TRANSACTIONS (pre-tagged or post-tagged) that were flowing and ordered to be reduced or totally curtailed. The CONTROL AREA will indicate to the IDC through the E-Tag adjustment table the INTERCHANGE TRANSACTION’S curtailed values.

3. **PROCEED:** INTERCHANGE TRANSACTION is flowing or has been permitted to flow as a result of Reloading/Reallocation evaluation. The CONTROL AREA will indicate through the E-Tag adjustment table to IDC if INTERCHANGE TRANSACTION will reload, start, or increase next-hour per PSE’s energy schedule as appropriate.

**Reallocation/Reloading Priorities**

1. INTERCHANGE TRANSACTION candidates are ranked for loading and curtailment by priority as per Appendix 9C1, Section E, “Principles for Mitigating Constraints On and Off the Contract Path”). This is called the “Constrained Path Method,” or CPM. (secondary, hourly, daily, … firm etc). INTERCHANGE TRANSACTIONS are curtailed and loaded pro-rata within priority level per TLR algorithm.

2. Reloading/Reallocation of INTERCHANGE TRANSACTIONS are prioritized first by priority per CPM. E-Tags must be submitted to the Interchange Distribution Calculator by the Approved-Tag Submission Deadline for Reallocation of the hour during which the INTERCHANGE TRANSACTION is scheduled to start or increase to be considered for Reallocation.

3. During Reloading/Reallocation, INTERCHANGE TRANSACTIONS using lower priority Transmission Service will be curtailed pro-rata to allow higher priority transactions to reload, increase, or start. Equal priority INTERCHANGE TRANSACTIONS will not reload, start, or increase by pro-rata curtailment of other equal priority INTERCHANGE TRANSACTIONS.

4. Reloading of INTERCHANGE TRANSACTIONS using Non-firm Transmission Service with CURTAILED Status will take precedence over starting or increasing of INTERCHANGE TRANSACTIONS using Non-firm Transmission Service of the same priority with PENDING Statuses.

5. INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission Service will be allowed to start as scheduled under TLR 3a as long as their E-Tag was received by the Interchange Distribution Calculator by the Approved-Tag Submission Deadline for Reallocation of the hour during which the INTERCHANGE TRANSACTION is due to start or increase, regardless of whether the E-tag was submitted to the Tag Authority prior to TLR 2 or higher being declared or not. If this is the initial issuance of the TLR 3a, INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission Service will be allowed to start as scheduled as long as their E-Tag was received by the Interchange Distribution Calculator by the time the TLR is declared.
Total Flow Value on a Constrained Facility for Next Hour

1. The RELIABILITY COORDINATOR will calculate the change in net flow on a CONSTRAINED FACILITY due to Reallocation for the next hour based on:

- Present CONSTRAINED FACILITY loading, present level of INTERCHANGE TRANSACTIONS, and CONTROL AREA NNL responsibility\(^2\) (TLR Level 5a) impacting the CONSTRAINED FACILITY,
- OPERATING SECURITY LIMITS, known interchange impacts and CONTROL AREA NNL responsibility (TLR Level 5a) on the CONSTRAINED FACILITY the next hour, and
- INTERCHANGE TRANSACTIONS scheduled to begin the next hour.

2. The RELIABILITY COORDINATOR will enter a maximum loading value for the CONSTRAINED FACILITY into the IDC as part of issuing the Reloading/Reallocation report.

3. The RELIABILITY COORDINATOR is allowed to call for TLR 3a or 5a when approaching an OPERATING SECURITY LIMIT to allow maximum transactional flow next hour, and to manage flows without violating transmission limits.

4. The simultaneous curtailment and Reallocation for a CONSTRAINED FACILITY is allowed. This reduces the flow over the CONSTRAINED FACILITY while allowing INTERCHANGE TRANSACTIONS using higher priority Transmission Service to start or increase the next hour. This may be used to accommodate change in flow next-hour due to changes other than point-to-point INTERCHANGE TRANSACTIONS while respecting the priorities of INTERCHANGE TRANSACTIONS flowing and scheduled to flow the next hour. The intent is to reduce the need for using TLR 3b, which prevents new INTERCHANGE TRANSACTIONS from starting or increasing the next hour.

5. The RELIABILITY COORDINATOR must allow INTERCHANGE TRANSACTIONS to be reloaded as soon as possible. Reloading must be in an orderly fashion to prevent an OPERATING SECURITY LIMIT violation from (re)occurring and requiring holding or curtailments in the restricted direction.

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\(^2\) Flows due to service to Network Customers and Native Load. See “Parallel Flow Calculation Procedure Reference Document.”
Attachment B – Timing Requirements

**TLR Levels 3a and 5a Issuing/Processing Time Requirement**

1. In order for the IDC to be reasonably certain that a TLR Level 3a or 5a re-allocation/reloading report in which all tags submitted by the Approved-Tag Submission Deadline for Reallocation are included, the report must be generated no earlier than 00:25 to allow the 10-minute approval time for TRANSACTIONS that start next hour.

2. In order to allow a RELIABILITY COORDINATOR to declare a TLR Level 3a or 5a any time during the hour, the TLR declaration and Re-allocation/Reloading report distribution will be treated as independent processes by IDC. That is, a RELIABILITY COORDINATOR may declare a TLR Level 3a or 5a at any time during the course of an hour. However, if a TLR Level 3a or 5a is declared for the next hour prior to 00:25 (see Figure 5 at right), the Re-allocation/Reloading report that is generated will be made available to the issuing RELIABILITY COORDINATOR only for previewing purposes, and can not be distributed to the other RELIABILITY COORDINATORS or the market. Instead, the issuing RELIABILITY COORDINATOR will be reminded by an IDC alarm at 00:25 to generate a new Re-allocation/Reloading report that will include all tags submitted prior to the Approved-Tag Submission Deadline for Reallocation.

3. A TLR Level 3a or 5a Re-allocation/Reloading report must be confirmed by the issuing RELIABILITY COORDINATOR prior to 00:30 in order to provide a minimum of 30 minutes for the RELIABILITY COORDINATORS with tags sinking in his RELIABILITY AREA to coordinate the Re-allocation and Reloading with the SINK CONTROL AREAS. This provides only 5 minutes (from 00:25 to 00:30) for the issuing RELIABILITY COORDINATOR to generate a Re-allocation/Reloading report, review it, and approve it.

4. The TLR declaration time will be recorded in the IDC for evaluating transaction sub-priorities for Re-allocation/Reloading purposes (see Subpriority Table, Page RAL-13).

**Re-Issuing of a TLR Level 2 or Higher**

Each hour, the IDC will automatically remind the issuing RELIABILITY COORDINATOR (via an IDC alarm) of a TLR level 2 or higher declared in the previous hour or earlier about re-issuing the TLR. The purpose of the reminder is to enable the RELIABILITY COORDINATOR to REALLOCATE or reload currently halted or curtailed INTERCHANGE TRANSACTIONS next hour. The reminder will be in the form of an alarm to the issuing RELIABILITY COORDINATOR, and will take place at 00:25 so that, if the RELIABILITY COORDINATOR re-issues the TLR as a TLR level 3a or 5a, all tags submitted prior to the Approved-Tag Submission Deadline for Reallocation are available in the IDC.

**IDC Assistance with Next Hour PTP Transactions**

In order to assist a RELIABILITY COORDINATOR in determining the MW relief required on a CONSTRAINED FACILITY for the next hour for a TLR level 3a or 5a, the IDC will calculate and present the total MW impact of all currently flowing and scheduled Point-to-Point TRANSACTIONS for the next hour. In order to assist a RELIABILITY COORDINATOR in determining the MW relief required on a CONSTRAINED FACILITY for the next hour during a TLR level 5a, the IDC will calculate and present the total MW impact of all currently flowing and scheduled Point-to-Point TRANSACTIONS for the next hour.
as well as Control Area with flows due to service to Network Customers and Native Load. The RELIABILITY COORDINATOR will then be requested to provide the total incremental or decremental MW amount of flow through the CONSTRAINED FACILITY that can be allowed for the next hour. The value entered by the RELIABILITY COORDINATOR and the IDC-calculated amounts will be used by the IDC to identify the relief/reloading amounts (delta incremental flow value) on the constrained facility. The IDC will determine the TRANSACTIONS to be reloaded, reallocated, or curtailed to make room for the TRANSACTIONS using higher priority TRANSMISSION SERVICE. The following examples show the calculation performed by IDC to identify the “delta incremental flow”:

**Example 1**

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Flow to maintain on Facility</td>
<td>800 MW</td>
</tr>
<tr>
<td>Expected flow next hour from Transactions using Point-to-Point Transmission Service</td>
<td>950 MW</td>
</tr>
<tr>
<td>Contribution from flow next hour from service to Network customers and Native Load</td>
<td>-100 MW</td>
</tr>
<tr>
<td>Expected Net flow next hour on Facility</td>
<td>850 MW</td>
</tr>
<tr>
<td>Amount of Transactions using Point-to-Point Transmission Service to hold for Reallocation</td>
<td>850 MW – 800 MW = 50 MW</td>
</tr>
<tr>
<td>Amount to enter into IDC for Transactions using Point-to-Point Transmission Service</td>
<td>950 MW – 50 MW = 900 MW</td>
</tr>
</tbody>
</table>

**Example 2**

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Flow to maintain on Facility</td>
<td>800 MW</td>
</tr>
<tr>
<td>Expected flow next hour from Transactions using Point-to-Point Transmission Service</td>
<td>950 MW</td>
</tr>
<tr>
<td>Contribution from flow next hour from service to Network customers and Native Load</td>
<td>50 MW</td>
</tr>
<tr>
<td>Expected Net flow next hour on Facility</td>
<td>1000 MW</td>
</tr>
<tr>
<td>Amount of Transactions using Point-to-Point Transmission Service to hold for Reallocation</td>
<td>1000 MW – 800 MW = 200 MW</td>
</tr>
<tr>
<td>Amount to enter into IDC for Transactions using Point-to-Point Transmission Service</td>
<td>950 MW – 200 MW = 750 MW</td>
</tr>
</tbody>
</table>

**Example 3**

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Flow to maintain on Facility</td>
<td>800 MW</td>
</tr>
<tr>
<td>Expected flow next hour from Transactions using Point-to-Point Transmission Service</td>
<td>950 MW</td>
</tr>
<tr>
<td>Contribution from flow next hour from service to Network customers and Native Load</td>
<td>-200 MW</td>
</tr>
<tr>
<td>Expected Net flow next hour on Facility</td>
<td>750 MW</td>
</tr>
<tr>
<td>Amount of Transactions using Point-to-Point Transmission Service to hold for Reallocation</td>
<td>750 MW – 800 MW = -50 MW</td>
</tr>
<tr>
<td>None are held</td>
<td></td>
</tr>
</tbody>
</table>
For a TLR levels 3b or 5b the IDC will request the RELIABILITY COORDINATOR to provide the MW requested relief amount on the CONSTRAINED FACILITY, and will not present the current and next hour MW impact of PTP transactions. The SC-entered requested relief amount will be used by IDC to determine the INTERCHANGE TRANSACTION CURTAILMENTS and flows due to service to Network Customers and Native Load (TLR Level 5b) in order to reduce the OPERATING SECURITY LIMIT violation on the CONSTRAINED FACILITY by the requested amount.

**IDC Calculations and Reporting Requirements**

At the time the TLR report is processed, the IDC will use all candidate INTERCHANGE TRANSACTIONS for REALLOCATION that met the Approved-Tag Submission Deadline for Reallocation plus those INTERCHANGE TRANSACTIONS that were curtailed or halted on the previous TLR action of the same TLR event. The IDC will calculate and present an INTERCHANGE TRANSACTIONS Halt/Curtailment list that will include reload and REALLOCATION of INTERCHANGE TRANSACTIONS. The INTERCHANGE TRANSACTIONS are prioritized as follows:

1. All INTERCHANGE TRANSACTIONS will be arranged by Transmission Service priority according to the Constrained Path Method. These priorities range from 1 to 6 for the various non-firm Transmission Service products (TLR levels 3a and 3b). INTERCHANGE TRANSACTIONS using Firm Transmission Service (priority 7) are used only in TLR levels 5a and 5b. Next-Hour Market Service is included at priority 0 (zero)

2. In a TLR Level 3a the INTERCHANGE TRANSACTIONS using Non-firm Transmission Service in a given priority will be further divided into four sub-priorities, based on current schedule, current active schedule (identified by the submittal of a tag ADJUST message), next-hour schedule, and tag status. Solely for the purpose of identifying which INTERCHANGE TRANSACTIONS to be loaded under a TLR 3a, various MW levels of an INTERCHANGE TRANSACTION may be in different sub-priorities. The sub-priorities are as follows:

<table>
<thead>
<tr>
<th>Priority</th>
<th>Purpose</th>
<th>Explanation and Conditions</th>
</tr>
</thead>
<tbody>
<tr>
<td>S1</td>
<td>To allow a flowing INTERCHANGE TRANSACTION to maintain or reduce its current MW amount in accordance with its energy profile.</td>
<td>The MW amount is the lowest between currently flowing MW amount and the next-hour schedule. The currently flowing MW amount is determined by the e-tag ENERGY PROFILE and ADJUST tables. If the calculated amount is negative, zero is used instead.</td>
</tr>
<tr>
<td>S2</td>
<td>To allow a flowing INTERCHANGE TRANSACTION that has been curtailed or halted by TLR to reload to the lesser of its current-hour MW amount or next-hour schedule in accordance with its energy profile.</td>
<td>The INTERCHANGE TRANSACTION MW amount used is determined through the e-tag ENERGY PROFILE and ADJUST tables. If the calculated amount is negative, zero is used instead.</td>
</tr>
<tr>
<td>S3</td>
<td>To allow a flowing TRANSACTION to increase from its current-hour schedule to its next-hour schedule in accordance with its energy profile.</td>
<td>The MW amounts used in this sub-priority is determined by the e-tag ENERGY PROFILE table. If the calculated amount is negative, zero is used instead.</td>
</tr>
<tr>
<td>S4</td>
<td>To allow a TRANSACTION that had never started and was submitted to the Tag Authority after the TLR (level 2 or higher) has been declared to begin flowing (i.e., the INTERCHANGE TRANSACTION never had an active MW and was submitted to the IDC after the first TLR Action of the TLR Event had been declared.)</td>
<td>The TRANSACTION would not be allowed to start until all other INTERCHANGE TRANSACTIONS submitted prior to the TLR with the same priority have been (re)loaded. The MW amount used is the sub-priority is the next-hour schedule determined by the e-tag ENERGY PROFILE table.</td>
</tr>
</tbody>
</table>
Examples of INTERCHANGE TRANSACTIONS using Non-firm Transmission Service sub-priority settings begin on page 16.

3. All INTERCHANGE TRANSACTIONS using Firm Transmission Service will be put in the same priority group, and will be Curtailed/Reallocated pro-rata, independent of their current status (curtailed or halted) or time of submittal with respect to TLR issuance (TLR level 5a). Under a TLR 5a, all INTERCHANGE TRANSACTIONS using Non-firm Transmission Service that is at or above the Curtailment Threshold will have been curtailed and hence sub-prioritizing is not required.

All INTERCHANGE TRANSACTIONS processed in a TLR are assigned one of the following statuses:

**PROCEED:** The INTERCHANGE TRANSACTION has started or is allowed to start to the next hour MW schedule amount.

**CURTAILED:** The INTERCHANGE TRANSACTION has started and is curtailed due to the TLR, or it had not started but it was submitted prior to the TLR being declared (level 2 or higher).

**HOLD:** The INTERCHANGE TRANSACTION had never started and it was submitted after the TLR being declared – the INTERCHANGE TRANSACTION is held from starting next hour or the transaction had never started and it was submitted to the Interchange Distribution Calculator after the Approved-Tag Submission Deadline – the INTERCHANGE TRANSACTION is to be held from starting next hour and is not included in the REALLOCATION calculations until following hour.

Upon acceptance of the TLR Transaction reallocation/reloading report by the issuing RELIABILITY COORDINATOR, the IDC will generate a report to be sent to NERC that will include the PSE name and Tag ID of each INTERCHANGE TRANSACTION in the IDC TLR report. The INTERCHANGE TRANSACTION will be ranked according to its assigned status of HOLD, CURTAILED or PROCEED. The reloading/reallocation report will be made available at NERC’s public TLR site, and it is NERC’s responsibility to format and publish the report.

**Tag Reloading for TLR Levels 1 and 0**
When a TLR Level 1 or 0 is issued, the CONSTRAINED FACILITY is no longer under OPERATING SECURITY LIMIT Violation and all INTERCHANGE TRANSACTIONS are allowed to flow. In order to provide the RELIABILITY COORDINATORS with a view of the INTERCHANGE TRANSACTIONS that were halted or curtailed on previous TLR actions (level 2 or higher) and are now available for reloading, the IDC provides such information in the TLR report.

**New Tag Alarming**
Those INTERCHANGE TRANSACTIONS that are at or above the Curtailment Threshold and are *not* candidates for reallocation because the tags for those Transactions were not submitted by the Approved-Tag Submission Deadline for Reallocation will be flagged as HOLD and must not be permitted to start or increase during the next hour. To alert RELIABILITY COORDINATORS of those TRANSACTIONS required to be held, the IDC will generate a report (for viewing within the IDC only) at various times. The report will include a list of all HOLD TRANSACTIONS. In order not to overwhelm the RELIABILITY COORDINATOR with alarms, only those who issued the TLR and those whose TRANSACTIONS sink within their
RELIABILITY AREA will be alarmed. An alarm will be issued for a given tag only once and will be issued for all TLR levels for which halting new TRANSACTIONS is required: TLR Level 2, 3a, 3b, 5a and 5b.

**Tag Adjustment**

The INTERCHANGE TRANSACTIONS with statuses of HOLD, CURTAILED or PROCEED must be adjusted by a Tag Authority or Tag Approval entity. Without the tag adjustments, the IDC will assume that INTERCHANGE TRANSACTIONS were not curtailed/held and are flowing at their specified schedule amounts.

1. INTERCHANGE TRANSACTIONS marked as CURTAILED should be adjusted to a cap equal to, or at the request of the originating PSE, less than the reallocated amount (shown as the MW CAP on the IDC report). This amount may be zero if the TRANSACTION is fully curtailed.

2. INTERCHANGE TRANSACTION marked as PROCEED should be adjusted to reload (NULL or to its MW level in accordance with its Energy Profile in the adjusted MW in the E-Tag) if the INTERCHANGE TRANSACTION has been previously adjusted; otherwise, if the INTERCHANGE TRANSACTION is flowing in full, the Tag Authority need not issue an adjust.

3. INTERCHANGE TRANSACTIONS marked as HOLD should be adjusted to 0 MW.

**Special Tag Status**

There are cases in which a tag may be marked with a composite state of ATTN_REQD to indicate that tag Authority/Approval failed to communicate or there is an inconsistency between the validation software of different tag Authority/Approval entities. In this situation, the tag is no longer subject to passive approval and its status change to IMPLEMENT may take longer than 10 minutes. Under these circumstances, the IDC may have a tag that is issued prior to the Tag Submittal Deadline that will not be a candidate for reallocation. Such tags, when approved by the TAG AUTHORITY, will be marked as HOLD and must be halted.

**Transaction Sub-Priority Examples**

The following describes examples of INTERCHANGE TRANSACTIONS using Non-firm Transmission Service sub-priority setting for a INTERCHANGE TRANSACTION under different circumstances of current-hour and next-hour schedules and active MW flowing as modified by tag adjust table in E-Tag.
Example 1 – Transaction curtailed, next-hour Energy Profile is higher

<table>
<thead>
<tr>
<th>Energy Profile: Current hour</th>
<th>20 MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Actual flow following curtailment: Current hour</td>
<td>10 MW</td>
</tr>
<tr>
<td>Energy Profile: Next hour</td>
<td>40 MW</td>
</tr>
</tbody>
</table>

Sub-priorities for Transaction MW:

<table>
<thead>
<tr>
<th>Sub-Priority</th>
<th>MW Value</th>
<th>Explanation</th>
</tr>
</thead>
<tbody>
<tr>
<td>S1</td>
<td>10 MW</td>
<td>Maintain current curtailed flow</td>
</tr>
<tr>
<td>S2</td>
<td>+10 MW</td>
<td>Reload to current hour Energy Profile</td>
</tr>
<tr>
<td>S3</td>
<td>+20 MW</td>
<td>Load to next hour Energy Profile</td>
</tr>
<tr>
<td>S4</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Example 2 – Transaction curtailed, next-hour Energy Profile is lower

<table>
<thead>
<tr>
<th>Energy Profile: Current hour</th>
<th>40 MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Actual flow following curtailment: Current hour</td>
<td>10 MW</td>
</tr>
<tr>
<td>Energy Profile: Next hour</td>
<td>20 MW</td>
</tr>
</tbody>
</table>

Sub-priorities for Transaction MW:

<table>
<thead>
<tr>
<th>Sub-Priority</th>
<th>MW Value</th>
<th>Explanation</th>
</tr>
</thead>
<tbody>
<tr>
<td>S1</td>
<td>10 MW</td>
<td>Maintain current curtailed flow</td>
</tr>
<tr>
<td>S2</td>
<td>+10 MW</td>
<td>Reload to lesser of current and next-hour Energy Profile</td>
</tr>
<tr>
<td>S3</td>
<td>+0 MW</td>
<td>Next-hour Energy Profile is 20MW, so no change in MW value</td>
</tr>
<tr>
<td>S4</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Example 3 – Transaction not curtailed, next-hour Energy Profile is higher

| Energy Profile: Current hour | 20 MW |
| Actual flow following curtailment: Current hour | 20 MW (no curtailment) |
| Energy Profile: Next hour | 40 MW |

<table>
<thead>
<tr>
<th>Sub-Priority</th>
<th>MW Value</th>
<th>Explanation</th>
</tr>
</thead>
<tbody>
<tr>
<td>S1</td>
<td>20 MW</td>
<td>Maintain current flow (not curtailed)</td>
</tr>
<tr>
<td>S2</td>
<td>+0 MW</td>
<td>Reload to lesser of current and next-hour Energy Profile</td>
</tr>
<tr>
<td>S3</td>
<td>+20 MW</td>
<td>Next-hour Energy Profile is 40MW</td>
</tr>
<tr>
<td>S4</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Appendix 9C1B – Interchange Transaction Reallocation During TLR 3a and 5a

Example 4 – Transaction not curtailed, next-hour Energy Profile is lower

| Energy Profile: Current hour | 40 MW |
| Actual flow following curtailment: Current hour | 40 MW (no curtailment) |
| Energy Profile: Next hour | 20 MW |

Sub-priorities for Transaction MW:

<table>
<thead>
<tr>
<th>Sub-Priority</th>
<th>MW Value</th>
<th>Explanation</th>
</tr>
</thead>
<tbody>
<tr>
<td>S1</td>
<td>20 MW</td>
<td>Reduce flow to next-hour Energy Profile (20MW)</td>
</tr>
<tr>
<td>S2</td>
<td>+0 MW</td>
<td>Reload to <em>lesser</em> of current and next-hour Energy Profile</td>
</tr>
<tr>
<td>S3</td>
<td>+0 MW</td>
<td>Next-hour Energy Profile is 20MW</td>
</tr>
<tr>
<td>S4</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Example 5 – TLR Issued before Transaction was scheduled to start

<table>
<thead>
<tr>
<th>Sub-Priority</th>
<th>MW Value</th>
<th>Explanation</th>
</tr>
</thead>
<tbody>
<tr>
<td>S1</td>
<td>0 MW</td>
<td>Transaction was not allowed to start</td>
</tr>
<tr>
<td>S2</td>
<td>+0 MW</td>
<td>Transaction was not allowed to start</td>
</tr>
<tr>
<td>S3</td>
<td>+20 MW</td>
<td>Next-hour Energy Profile is 20MW</td>
</tr>
<tr>
<td>S4</td>
<td>+0</td>
<td>Tag submitted prior to TLR</td>
</tr>
</tbody>
</table>
Appendix 9C1C – Interchange Transaction Curtailments During TLR Level 3b

Appendix Subsections
A. Basic Principles
B. Considerations for Interchange Transactions using Firm Point-to-Point Transmission Service

Introduction

This Appendix provides the details for implementing TLR Level 3b, which curtails INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Transmission Service to assist the RELIABILITY COORDINATOR to recover from OPERATING SECURITY LIMIT violations.

TLR Level 3b curtails INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Transmission Service that are at or above the CURTAILMENT THRESHOLD. (See Appendix 9C1, “TLR Procedure – Eastern Interconnection,” Section B.4, “TLR Level 3b.”). Furthermore, all new INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Transmission Service that are at or above the CURTAILMENT THRESHOLD during the TLR 3b implementation period are halted or held. TRANSACTIONS using Firm Point-to-Point Transmission Service will be allowed to start if they are submitted to the IDC within specific time limits as explained in Section C, “Considerations for Interchange Transactions using Firm Point-to-Point Transmission Service.” Those Interchange Transactions using Firm Point-to-Point Transmission Service that are not submitted to the IDC within these time limits will be held.

A. Basic Principles

1. TLR 3b may be called at any time to help the RELIABILITY COORDINATOR mitigate an OPERATING SECURITY LIMIT violation.

2. Only those INTERCHANGE TRANSACTIONS at or above the CURTAILMENT THRESHOLD will be considered for curtailment, holding, or halting.

3. Existing INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Transmission Service will be curtailed as necessary to provide the required relief on the CONSTRAINED FACILITY.

4. If INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission Service are scheduled to start during the current hour or the following hour, additional INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Transmission Service will be curtailed to provide room for those INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission Service.

5. Existing INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Transmission Service that are not curtailed will not be allowed to increase (they may flow at the same or reduced level).

6. There is no Reallocation of INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Transmission Service during a TLR 3b.

7. INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission Service will be allowed to start as explained in Section C, “Considerations for Interchange Transactions using Firm Point-to-Point Transmission Service.”
8. If, after all Interchange Transactions using Non-firm Point-to-Point Transmission Service have been curtailed and there is insufficient room for Interchange Transactions using Firm Point-to-Point Transmission Service to start as scheduled, the RELIABILITY COORDINATOR will progress to TLR Level 5b as necessary.

9. The IDC will issue ADJUST Lists to the Generation and Load Control Areas and the PURCHASING-SELLING ENTITY who submitted the tag. The ADJUST List will include:

   a. INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Transmission Service that are to be curtailed, halted, or held during Current and Next hours.

   b. INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission Service that were entered after 00:25 or issuance of TLR 3b (see Case 3 in Section C below.

10. The LOAD CONTROL AREA must send the ADJUST Tables back to the IDC as soon as possible to ensure the most accurate calculations for actions subsequent to the TLR 3b being called.

11. The RELIABILITY COORDINATOR may call a TLR Level 3a as soon as the OPERATING SECURITY LIMIT Violation has been mitigated.

   a. If the TLR Level 3a is called before the hour 01, then a Reallocation will be computed for the start of that hour.

   b. Transactions must be in the IDC by the Approved-tag Submission Deadline for Reallocation (see Appendix 9C1B, “Interchange Transaction Reallocation During TLR Levels 3a and 5a,” Section B).
B. Considerations for Interchange Transactions using Firm Point-to-Point Transmission Service

The following cases explain the circumstances under which an Interchange Transaction using Firm Point-to-Point Transmission Service will be allowed to start as scheduled during a TLR 3b:

Case 1: TLR 3b is called between 00:00 and 00:25 and the Interchange Transaction using Firm Point-to-Point Transmission Service is submitted to IDC by 00:25.

1. The IDC will examine the current hour (00) and next hour (01) for all INTERCHANGE TRANSACTIONS.
2. The IDC will issue an ADJUST List based upon the time the TLR 3b is called. The ADJUST List will include curtailments of Interchange Transactions using Non-firm Point-to-Point Transmission Service as necessary to allow room for those Interchange Transactions using Firm Point-to-Point Transmission Service to start as scheduled.
3. At 00:25, the IDC will check for additional Interchange Transactions using Firm Point-to-Point Transmission Service that were submitted to the IDC by that time and issue a second ADJUST List if those additional Interchange Transactions are found.
4. All existing or new INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Transmission Service that are increasing or expected to start during the current hour or next hour will be placed on HALT or HOLD. There is no Reallocation of lower-priority INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Transmission Service.
5. INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission Service that were submitted to the IDC by 00:25 will be allowed to start as scheduled.
6. INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission Service that were submitted to the IDC after 00:25 will be held.
7. Once the OPERATING SECURITY LIMIT Violation is mitigated, the RELIABILITY COORDINATOR shall call a TLR Level 3a (or lower). If a TLR Level 3a is called:

   a. INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission Service that were submitted to the IDC by 00:25 will be allowed to start as scheduled at 02:00.

   b. INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Transmission Service that were held may then be reallocated to start at 02:00.
Appendix 9C1C – Curtailments During TLR 3b

Case 2: TLR 3b is called after 00:25 and the Interchange Transaction using Firm Point-to-Point Transmission Service is submitted to the IDC no later than the time at which the TLR 3b is called.

1. The IDC will examine the current hour (00) and next hour (01) for all INTERCHANGE TRANSACTIONS.

2. The IDC will issue an ADJUST List at the time the TLR 3b is called. The ADJUST List will include additional curtailments of Interchange Transactions using Non-firm Point-to-Point Transmission Service as necessary to allow room for those Interchange Transactions using Firm Point-to-Point Transmission Service to start at as scheduled.

3. All existing or new INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Transmission Service that are increasing or expected to start during the current hour or next hour will be placed on HALT or HOLD. There is no Reallocation of lower-priority INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Transmission Service.

4. INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission Service that were submitted to the IDC by the time the TLR 3b was called will be allowed to start at as scheduled.

5. Interchange Transaction using Firm Point-to-Point Transmission Service that were submitted to the IDC after the TLR 3b was called will be held until the next issuance for TLR (either TLR 3b, 3a, or lower level.)
Case 3. TLR 2 or higher is in effect, a TLR 3b is called after 00:25, and the Interchange Transaction using Firm Point-to-Point Transmission Service is submitted to the IDC by 00:25.

If TLR 2 or higher has been issued and 3B is subsequently issued, then only those INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission Service that had been submitted to the IDC by 00:25 will be allowed to start as scheduled. All other INTERCHANGE TRANSACTIONS are held.
Case 4. TLR 3b is called before 00:25 and the Interchange Transaction is submitted to the IDC by 00:25. TLR 3a is called at 00:40.

1. Same as Case 1, but TLR Level 3b ends at 00:40 and becomes TLR Level 3a.

2. All Interchange Transactions using Firm Point-to-Point Transmission Service will start as scheduled if in by the time the 3A is declared.

3. All INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Transmission Service are reallocated at 01:00.
Case 5. TLR 3b is called before 00:25 and the Interchange Transaction is submitted to the IDC by 00:25. TLR 1 is called at 00:40.

1. Same as Case 1, but TLR Level 3b ends at 00:40 and becomes TLR Level 1.

2. All INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission Service will start as scheduled.

3. All INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Transmission Service may be loaded immediately.
Appendix 9C2
WECC Unscheduled Flow Reduction Procedure

[WECC Reliability Criteria: http://www.wecc.biz/site_map.html# ]

Appendix Subsections

1. Transfer Path Qualification
2. Transfer Path Re-qualification
3. Transfer Path Deletion
4. Actions Required Following Addition of a New Qualified Transfer Path
5. Controllable Device Qualification
6. Controllable Device Deletion
7. Accommodation Limits
8. General Terms
9. General Action Rules
10. Action Steps
11. Further Action
12. Term

The combination of scheduled and unscheduled flows on a Transfer Path may exceed the transfer capability of that Transfer Path. This Unscheduled Flow Reduction Procedure (USF Reduction Procedure) will be utilized to reduce the Unscheduled Flows (USF) across a constrained Qualified Transfer Path. The USF Reduction Procedure has the following parts:

1. Transfer Path Qualification
2. Transfer Path Re-qualification
3. Transfer Path Deletion
4. Actions Required Following Addition of a New Qualified Transfer Path
5. Controllable Device Qualification
6. Controllable Device Deletion
7. Accommodation Limits
8. General Terms
9. General Action Rules
10. Action Steps
11. Further Action
12. Term

This USF Reduction Procedure addresses the actions, which are required by all Members. This USF Reduction Procedure recognizes the effectiveness of coordinated control and operation of the Qualified Controllable Devices installed within the WECC systems. It is subject to review for its effectiveness (Section 13 of the Plan) and modification as provided in Section 5.2 of the Plan.

When a Qualified Transfer Path is constrained by USF, the Transfer Path Operator will notify all Members via the WECC communications system, and Members will take actions as required by this USF Reduction Procedure to reduce the effects of USF across the Qualified Transfer Path. Where Schedule adjustments are required by this USF Reduction Procedure, it is the responsibility of the
Appendix 9C2 – WECC Unscheduled Flow Reduction Procedure

Member who is a Receiver to determine if any mitigation steps are required, and if so, to initiate appropriate actions. If the ultimate Receiver is not a Member, then the scheduling change administration responsibility shall belong to the Member most closely associated with the Schedule to the non-Member.

This USF Reduction Procedure is not intended to be prescriptive with regard to which Schedules are to be adjusted to effect the required USF Accommodation or Schedule reduction. Rather, when actions are required to reduce the effects of USF, it is expected that each Member will select the most appropriate Schedule reduction which will satisfy the intended accommodation and curtailment responses required by this USF Reduction Procedure.

Terms which are initially capitalized in this USF Reduction Procedure refer to defined terms in the WECC Unscheduled Flow Mitigation Plan.

1. Transfer Path Qualification

Requests for Transfer Path qualification shall be made directly to the UFAS. To qualify a Transfer Path under this Plan, a Transfer Path Operator must specify the applicable direction and provide documentation to satisfy the requirements for qualification set forth below:

a. The Transfer Path must be a transmission element or elements across which:
   i. a Schedule (MW) can be established,
   ii. Actual Flow (MW) is metered, and
   iii. Maximum Transfer Limit has been established and published in WECC Planning Coordination Committee or WECC Operations Committee documents.

b. An historical record exists to document that:
   i. for at least 100 hours in the most recent 36 months, Actual Flow across a Transfer Path (MW) has exceeded 97 percent of the Maximum Transfer Limit in MW, and at the same time
   ii. energy Schedules were curtailed because of USF.

c. The prospective Transfer Path Operator will be expected to make a presentation to the UFAS explaining how the Maximum Transfer Limit was determined and how the historical Actual Flow and/or Schedule curtailment records were obtained.

d. An incremental matrix for the current operating season and applicable to the proposed Transfer Path confirms that a feasible combination of Schedules between Sender and Receiver can create USF across the Transfer Path whose sum is equal to or greater than five percent of the Maximum Transfer Limit.

e. After the UFAS has reviewed the documentation and presentation, a recommendation will be forwarded to the WECC Operations Committee. The Transfer Path Operator may be requested to make a presentation to the WECC Operations Committee.

f. A Transfer Path is normally qualified for USF reduction in only one direction. The Transfer Path may be qualified for USF reduction in both directions, but supporting data must be provided for each direction.

2. Transfer Path Re-qualification

If there is a change in the Maximum Transfer Limit for an existing Qualified Transfer Path or the addition of a Controllable Device in the Qualified Transfer Path, the Transfer Path
Operator shall make a presentation to the UFAS so that the UFAS can determine if re-qualification of the Qualified Transfer Path is necessary.

3. Transfer Path Deletion

If there have been no Schedule reductions or USF Accommodations and the Actual Flow across a Qualified Transfer Path has not exceeded 97 percent of the Maximum Transfer Limit for the most recent 36 months, the UFAS shall make a determination as to whether the WECC system configuration has been altered sufficiently so that USF Schedule reductions or USF Accommodation on the Qualified Transfer Path would no longer be expected. An affirmative finding of the UFAS and approval by the WECC Operations Committee will be required to delete a Qualified Transfer Path.

4. Actions Required Following Addition of a New Qualified Transfer Path

a. A new Transfer Path will be added to the list of Qualified Transfer Paths, attached as Exhibit A, upon approval of the WECC Operations Committee.
b. Owners of facilities making up a Qualified Transfer Path will designate a Transfer Path Operator.
c. Incremental power flow matrices will be prepared for the current summer and winter seasons based on appropriately modified operating base cases for each Qualified Transfer Path and provided to the WECC Operations Committee members. The matrices will be based on an incremental schedule of 100 MW and express results in units of MW (equivalent to percent of individual Schedule). They will be used to determine the magnitude of each Contributing Schedule's contribution to USF. A "Contributing Schedule" is defined as the net Schedule between individual Senders and Receivers that contributes USF across a Qualified Transfer Path in the same direction as the Actual Flow across that Qualified Transfer Path.
d. The effectiveness factors and compensation for the Qualified Controllable Devices will be recalculated.

5. Controllable Device Qualification

a. Any Member wishing to qualify a Controllable Device to receive compensation for coordinated operation under the Plan shall present a plan for coordinated operation to the UFAS. This plan should include the following elements:

i. The procedures developed to ensure that adequate communication and coordination occurs between the Member's Controllable Device and other Qualified Controllable Devices to achieve the desired coordination,

ii. A demonstration that by adding the Member's Controllable Device to the overall coordinated Controllable Device control strategy, using the Controllable Devices Compensation Methodology (Attachment 3), the proposed Controllable Device will reduce USF:

(1) by an average over all of the then Qualified Transfer Paths of at least one percent of the respective Qualified Transfer Path limits, (which corresponds to average percent control of 6.7 percent in Table I of Attachment 3), and
(2) for more than half of the Qualified Transfer Paths, by at least one percent of each of the respective Qualified Transfer Path limits.

b. After the UFAS has reviewed the documentation and presentation, it will make a recommendation to the WECC Operations Committee. Upon approval by the WECC Operations Committee, the proposed Controllable Device will be added to the list of Qualified Controllable Devices.

6. Controllable Device Deletion

a. A Qualified Controllable Device shall be deleted from the list of Qualified Controllable Devices if the Controllable Device is no longer capable of reducing USF over all of the then Qualified Transfer Paths by the criteria specified in Section 5.a above. The Controllable Device will no longer be required to participate in coordinated operation. However, its continued participation is encouraged.

7. Accommodation Limits

a. During normal operating conditions when Actual Flow is not exceeding the Transfer Limit and desired Schedules are not being curtailed, the Qualified Transfer Path(s) will accommodate 100 percent of the USF.

b. During those times when there is or it is anticipated that there will be a scheduling limitation on a Qualified Transfer Path due to USF, the Transfer Path Operator and those scheduling across the Qualified Transfer Path are required to accommodate a minimum level of USF. Such USF Accommodation will be achieved by ensuring that the net Schedules across the Qualified Transfer Path are reduced below the then available Transfer Limit by the following amount:

i. The greater of 50 MW or
   (1) during the first Plan Year, 10 percent of the Transfer Limit;
   (2) during the second Plan Year, 7.5 percent of the Transfer Limit; or
   (3) during the third and subsequent Plan Years, 5 percent of the Transfer Limit.

c. If net Schedules are reduced below the Transfer Limit by the amounts specified above, then the Transfer Path Operator has met the USF Accommodation requirement and may request additional relief under the Plan, including coordinated operation of Qualified Controllable Devices, and Schedule curtailments by other Receivers who are scheduling across other Transfer Paths.

d. It is intended that the Qualified Controllable Devices shall not be requested to operate in a coordinated manner in response to requests under this USF Reduction Procedure in excess of 2000 hours per year, and if operation exceeds or is forecast to exceed that level, then the level of Transfer Path USF Accommodation shall be increased such that coordinated operation shall not exceed 2000 hours annually. The UFAS shall monitor the coordinated operation of the Qualified Controllable Devices and recommend to the WECC Operations Committee adjustments to the level of USF Accommodation as needed to meet this objective.
8. **General Terms**
   
a. All Members shall cooperate with the Transfer Path Operator by reducing Schedules as requested to achieve the appropriate reduction in USF. Schedule reductions required by this USF Reduction Procedure may be taken in either the Contributing Schedule, or any other Schedule, the reduction of which achieves the equivalent effect on reducing USF on the affected Transfer Path.

b. Members having Controllable Devices, such as series capacitors, phase shifting transformers, and DC transmission lines shall cooperate with the Transfer Path Operator to the extent practical by using these elements to reduce USF across the constrained Qualified Transfer Path. Operation of such Controllable Devices shall be required where the Controllable Devices are being operated in a coordinated manner pursuant to the Plan. Operation of Controllable Devices (which are not Qualified Controllable Devices) shall be at the discretion of and consistent with the normal practice of the Member. Schedule reductions shall not be required by the Member to the extent that controllable elements (which are not operated in a coordinated manner) are operated to achieve an equivalent reduction in USF across the constrained Qualified Transfer Path.

c. To the extent that a Qualified Controllable Device is capable of operating to achieve Actual Flows through the Controllable Device equal to Scheduled Flows, such Schedules shall be deemed to be 100 percent effective through the Controllable Device, and thus shall be exempt from the Schedule reductions required under this USF Reduction Procedure.

d. The WECC Staff will provide a summary of all qualified controllable elements, which are being operated in a coordinated manner pursuant to the Plan, whenever a new Controllable Device is qualified pursuant to the Plan. This summary shall be provided to the WECC Operations Committee.

9. **General Action Rules**
   
a. This procedure applies to all Members.

b. The UFAS shall develop guidelines to enable the Transfer Path Operators to implement actions under this USF Reduction Procedure, which will achieve the desired accommodation/control/curtailment results in the scheduling hour immediately following the request. Furthermore, these guidelines shall enable the Transfer Path Operators to make an initial request for any step in the procedure up through the NINTH STEP, provided however that the guidelines shall ensure that neither over-control nor over-curtailment shall be expected. Until such guidelines are developed, the following action limits shall apply:
   
i. The Transfer Path Operator may request actions through the FOURTH STEP in the first hour if experience indicates that such action will be needed to achieve the required reduction in USF.
   
   ii. For requests beyond the FOURTH STEP, no more than three requests may be initiated in any clock hour. The notice must specify if this is an FIFTH, SIXTH, SEVENTH, EIGHTH, OR NINTH STEP request. The request must be transmitted to Members by at least 30 minutes prior to the hour to ensure implementation for the following Schedule hour.
c. The Transfer Path Operator will verify, if possible, the magnitude of USF across the Qualified Transfer Path by checking adjacent metered and scheduled values prior to requesting any other Member to take actions under this USF Reduction Procedure.

d. As to the actions to be taken in accordance with this Plan for each hour of a curtailment period, each Member shall promptly provide documentation of all such accommodation, control or curtailment actions taken by its dispatchers or real-time schedulers, and in addition each Transfer Path Operator shall provide such documentation on such actions taken or not taken by others in response to its requests, to the WECC Staff following each curtailment period. Members' documentation shall use formats and reporting conventions developed and monitored by the WECC Operations Committee. The compiled information, including identification of Members who failed to adjust Schedules according to this USF Reduction Procedure, shall be promptly distributed to the WECC Operations Committee members.

e. Operation of Qualified Controllable Devices will be monitored by the WECC Operations Committee for compliance with the Minimum Operating Reliability Criteria and the WECC Controllable Devices Coordinated Operating Procedure. Results will be distributed to the WECC Operations Committee members.

f. The WECC Operations Committee shall monitor major loop USF in a minimum of four locations during hours in which any USF Accommodation or coordinated operation of the Qualified Controllable Devices or curtailments are occurring under this USF Reduction Procedure.

g. The Transfer Path Operator and those scheduling across the constrained Qualified Transfer Path will continue to take actions necessary to reduce Actual Flow to a level at or below the Transfer Limit of the Qualified Transfer Path.

h. Upon receipt of a curtailment request, Contributing Schedules which are subject to curtailments will be reduced (or equivalent alternative Schedule adjustments will be effected) in accordance with the following procedures:

i. Receivers of Contributing Schedules will initiate the requested Schedule reductions unless an otherwise agreed upon procedure for Schedule reduction achieving the equivalent effect on the Qualified Transfer Path is established by the Receiver and/or the Sender. If the ultimate Receiver is not a Member, then the curtailment administration responsibility shall first belong to the Member utility that has scheduling responsibility for the Receiver, and then to the Member utility that has control area responsibility for the Receiver.

ii. Members may arrange among themselves to make curtailments called for by this USF Reduction Procedure in a manner other than prescribed provided that the arrangements are as effective as the identified Schedule curtailment in reducing USF across the Qualified Transfer Path. Members may make bilateral arrangements, which will enable a Member with Schedules on the affected Qualified Transfer Path to make the required curtailments in lieu of making larger curtailments in Schedules over other parallel paths. Where alternative Schedule adjustments are utilized, it is the Receiver's responsibility to cause Schedule adjustments to be effected which provide the same reduction in flow across the Qualified Transfer Path as would have been achieved by the prescribed reduction in the Contributing Schedule.

iii. The total amount of requested Schedule reduction may be apportioned to the applicable Schedules at the discretion of the Receiver subject to item iv below.
iv. Irrespective of the Schedules reduced or the manner in which they are reduced, each Member's overall net reduction in Actual Flow across the constrained Qualified Transfer Path must be equivalent to the reduction which would have been achieved had the identified Schedule reduction occurred as requested.

v. System dispatchers or real-time schedulers should identify in advance those Schedules that qualify for curtailment requests for all Qualified Transfer Paths. This will expedite implementation of this USF Reduction Procedure when requested.

vi. While this USF Reduction Procedure does not expect Receivers to curtail Schedule, which would result in loss of firm load, nothing in this USF Reduction Procedure shall relieve the Receiver of the obligation to achieve the required reduction in USF across the constrained Qualified Transfer Path.

vii. In the event of a transmission system emergency on any Member's system, such Member may request coordinated operation of the Qualified Controllable Devices if such operation is reasonably expected to assist in relieving the emergency condition.

10. Action Steps

a. Action Taken by the Transfer Path Operator – Notification of Curtailment Period

   i. The Transfer Path Operator shall advise the Members via the WECC communications system of a current or an impending curtailment period, and may request assistance in mitigating the curtailment using the following procedure:

The following actions shall become effective at the start of the next scheduling hour following the request.

b. Action Taken by the Transfer Path Operator – Controllable Devices

   i. FIRST STEP: If the Qualified Transfer Path contains series connected Controllable Devices, such as series capacitors, phase shifting transformers, and DC transmission lines, these elements will be used to the maximum extent practical in reducing the USF across the constrained Qualified Transfer Path to a level at or below the Transfer Limit. Operations of such Controllable Devices shall comply with the WECC Minimum Operating Reliability Criteria.

c. Action Taken by the Transfer Path Operator - Accommodation

   i. SECOND STEP: USF across a Qualified Transfer Path will be accommodated up to the greater of 50 MW or 10 percent of the Transfer Limit for that Qualified Transfer Path in the first Plan Year, 7.5 percent in the second Plan Year, and 5 percent in the third and subsequent Plan Years. USF Accommodation will be effected by the Transfer Path Operator causing the net Schedules across the Qualified Transfer Path to be reduced to not more than 90 percent of the Transfer Limit for that Qualified Transfer Path in the first Plan Year, 92.5 percent in the second Plan Year, and 95 percent in the third and subsequent Plan Years. The Transfer Path Operator shall not be expected to reduce net Schedules across the Qualified Transfer Path in this
Appendix 9C2 – WECC Unscheduled Flow Reduction Procedure

step if they are already below the appropriate USF Accommodation level (90 percent, 92.5 percent, or 95 percent of the Transfer Limit).

d. Actions Taken by Controllable Device Owners
i. THIRD STEP: At the request of a Transfer Path Operator, the Qualified Controllable Device owners shall operate their Controllable Devices in a coordinated manner so as to minimize the USF on the constrained Qualified Transfer Path, consistent with the WECC Minimum Operating Reliability Criteria. If the constraint persists, then;

e. Actions Taken by Others and the Transfer Path Operator – Curtailment of Schedules.

i. FOURTH STEP: Those Receivers with Contributing Schedules that result in USF across the constrained Qualified Transfer Path of 50 percent or more will effect a scheduling change which is intended to reduce the USF across the Qualified Transfer Path by the same amount as would a 20 percent reduction in the Contributing Schedule. Those Receivers with Contributing Schedules that result in USF across the constrained Qualified Transfer Path of from 30 percent to 49 percent will effect a scheduling change which is intended to reduce the USF across the Qualified Transfer Path by the same amount as would a 10 percent reduction in the Contributing Schedule. If the overload persists, then;

ii. FIFTH STEP: Those Receivers with Contributing Schedules that result in USF across the constrained Qualified Transfer Path of from 20 through 29 percent will effect a scheduling change which is intended to reduce the USF across the Qualified Transfer Path by the same amount as would a 10 percent reduction in the Contributing Schedule, and Receivers with Contributing Schedules that result in USF across the constrained Qualified Transfer Path of 30 percent or more will effect a scheduling change which is intended to reduce the USF across the Qualified Transfer Path by the same amount as would an additional 5 percent reduction in the Contributing Schedule. If the overload persists, then;

iii. SIXTH STEP: USF Accommodation on the Qualified Transfer Path will increase to the greater of 75 MW or 11 percent of the Transfer Limit for that Qualified Transfer Path in the first Plan Year, 8.5 percent in the second Plan Year, and 6 percent in the third and subsequent Plan Years. Contributing Schedules will continue to be curtailed as described up through the FIFTH STEP. If the overload persists, then;

iv. SEVENTH STEP: Those Receivers with Contributing Schedules that result in USF across the constrained Qualified Transfer Path of from 15 through 19 percent will effect a scheduling change which is intended to reduce the USF across the Qualified Transfer Path by the same amount as would a 10 percent reduction in the Contributing Schedule, and Receivers with Contributing Schedules that result in USF across the constrained Qualified Transfer Path of 20 percent or more will effect a scheduling change which is intended to reduce the USF across the Qualified Transfer Path by the same amount as would an additional 5 percent reduction in the Contributing Schedule.

v. EIGHTH STEP: USF Accommodation on the Qualified Transfer Path will increase to the greater of 100 MW or 12 percent of the Transfer Limit for that Qualified Transfer Path in the first Plan Year, 9.5 percent in the second Plan Year, and 7 percent in the third and subsequent Plan Years. Contributing
Schedules will continue to be curtailed as described up through the SEVENTH STEP. If the overload persists, then;

vi. NINTH STEP: Those Receivers with Contributing Schedules that result in USF across the constrained Qualified Transfer Path of from 10 to 14 percent will effect a scheduling change which is intended to reduce the USF across the Qualified Transfer Path by the same amount as would a 10 percent reduction in the Contributing Schedule, and Receivers with Contributing Schedules that result in USF across the constrained Qualified Transfer Path of 15 percent or more will effect a scheduling change which is intended to reduce the USF across the Qualified Transfer Path by the same amount as would an additional 5 percent reduction in the Contributing Schedule.

11. Further Action
   a. The Transfer Path Operator and those scheduling across the constrained Qualified Transfer Path will continue to take actions necessary to reduce Actual Flow to a level at or below the Transfer Limit.
   b. The Transfer Path Operator and those scheduling across the Qualified Transfer Path may resume some Schedules as curtailment steps are taken by others provided the net Schedule remains at or below the amount that provides for USF Accommodation at the level specified above for the Qualified Transfer Path.
   c. The Transfer Path Operator must reconfirm the need to continue the present level of Schedule reductions via the WECC communications system every four hours by at least 30 minutes to the hour.
   d. The Transfer Path Operator must notify Members via the WECC communications system to reduce Schedule curtailments when the Actual Flow on the Qualified Transfer Path is reduced below 97 percent of its Transfer Limit or the USF Accommodation levels above are no longer being exceeded. Schedules should be resumed in the reverse order that Schedule curtailments were initiated. If conditions warrant, the Transfer Path Operator may notify all Members to cease all curtailments at any time.

12. Term
   This procedure will remain in effect coterminous with the Plan.

Revised: February 10, 1994
# WECC UNSCHEDULED FLOW PROCEDURE
## SUMMARY OF CURTAILMENT ACTIONS

<table>
<thead>
<tr>
<th>Step</th>
<th>Action Description</th>
<th>Party(s) Affected</th>
<th>Unscheduled Flow Accommodation across Path (First Contract Year/Second Contract Year/Third and subsequent Contract Years)</th>
<th>Equivalent Percent Curtailment Required in Contributing Schedule -Based on amount of Unscheduled Flow across Path</th>
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<td></td>
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<td>10-14%</td>
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<td>Operate controllable devices in Path</td>
<td>Controllable devices in transfer Path</td>
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<td>2</td>
<td>Accommodation</td>
<td>Schedules across the Path</td>
<td>50 MW or 10%/7.5%/5% of maximum transfer limit</td>
<td>10%</td>
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<tr>
<td>3</td>
<td>Coordinated operation of qualified controllable devices</td>
<td>Qualified controllable devices</td>
<td>50 MW or 10%/7.5%/5% of maximum transfer limit</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>First level curtailment</td>
<td>Schedules in other paths</td>
<td>50 MW or 10%/7.5%/5% of maximum transfer limit</td>
<td></td>
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<td>Second level curtailment</td>
<td>Schedules in other paths</td>
<td>50 MW or 10%/7.5%/5% of maximum transfer limit</td>
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<tr>
<td>6</td>
<td>Accommodation</td>
<td>Schedules across Path</td>
<td>75 MW or 11%/8.5%/6% of maximum transfer limit</td>
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<td>7</td>
<td>Third level curtailment</td>
<td>Schedules in other paths</td>
<td>75 MW or 11%/8.5%/6% of maximum transfer limit</td>
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<tr>
<td>8</td>
<td>Accommodation</td>
<td>Schedules across Path</td>
<td>100 MW or 12%/9.5%/7% of maximum transfer limit</td>
<td></td>
</tr>
<tr>
<td>9</td>
<td>Fourth level curtailment</td>
<td>Schedules in other paths</td>
<td>100 MW or 12%/9.5%/7% of maximum transfer limit</td>
<td></td>
</tr>
</tbody>
</table>
Appendix 9C3
ERCOT Operating Guide III, Operation To
Maintain Transmission System Security

[ERCOT Operating Guides: http://www.ercot.com/eguides.htm ]

Control Area Operators are responsible for operating their systems within first contingency transfer limits so that there is no overload of any significant transmission element whose loss could jeopardize the reliability of the interconnection. “First contingency” criteria are specified in Operating Guide V.

The ISO can order the following actions when the above criteria is not met if such actions assists the Control Areas in meeting their responsibilities:

1. **Significant Transmission Overload** – The ISO can order curtailment of power transfers, switching of transmission elements or load interruption to relieve a severely overloaded transmission element. The ISO can order a severely overloaded transmission element whose loss would not have a significant impact on the reliability of ERCOT transmission system switched out to increase interconnected system transfers when such transfers are needed to maintain system reliability.

2. **Violation of “First Contingency” Criteria** – The ISO can order redispatch if necessary to eliminate a “first contingency” criteria violation.

3. **Violation of Voltage/Reactive Criteria** – The ISO can order a redispatch if coordinated voltage and reactive power criteria that are considered critical to interconnection reliability for the existing or first contingency conditions are violated.
TRAINING DOCUMENTS
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 frequency$^1$ — 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.

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$^1$When 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

$$ACE = (N_{iA} - N_{iS}) - 10\beta(f_A - f_S)$$

for the Western Interconnection

$$ACE = (N_{iA} - N_{iS}) - 10\beta(f_A - f_S) - s(0.3\beta_t t_d)$$

where,

- $N_{iA}$ = 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.

- $N_{iS}$ = 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.

- $\beta$ = 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 $t_i$ is positive and the CONTROL AREA’S accumulation of inadvertent interchange is positive, or if $t_i$ is negative and the CONTROL AREA’S inadvertent interchange is negative. $s = 0$ for all other conditions.

- $\beta_t$ = 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, $\beta$.

- $t_d$ = Time error (seconds). 1 second maximum.
Area Interchange Error (AIE). The formula for calculating the AIE is the same as the ACE, except that hourly integrated values are used:

\[ AIE = (NIA - NIS) - 10\beta(F_A - F_S) \]

for the Eastern and Texas INTERCONNECTIONS, and

\[ AIE = (NIA - NIS) - 10\beta(F_A - F_S) - s(0.3\beta T_d) \]

for the Western INTERCONNECTION

where,

\( NIA = \) Actual net interchange (MWh) \( \times \) 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.

\( NIS = \) Scheduled net interchange (MWh) \( \times \) 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) \( \times \) the actual average frequency in the INTERCONNECTION for the survey period.

\( F_S = \) Scheduled frequency (Hz) \( \times \) the scheduled average frequency in the Interconnection for the survey period.

\( \beta = \) Frequency bias setting (MW/0.1 Hz) \( \times \) 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.

\( \beta_t = \) Time error bias (MW/0.1 Second) \( \times \) the bias value used by the CONTROL AREA to correct for time error. It is has the same sign and value as the frequency bias, \( \beta \).

\( T_d = \) 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. Line 9 = Line 7 x Line 8 x 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 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. Line 4 + Line 5 = Scheduled Net Interchange, NIₜₜ.
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. Line 9 = Line 7 x Line 8 x 10.0.

Line 9a: Enter the control bias obligation to correct time error. Line 9a = Line 7a x Line 8 x 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 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  

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<td>Hr. Ending (CST/CDT):</td>
<td>Control Area:</td>
<td>Region:</td>
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<td></td>
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<tr>
<td>2: Control Area or Interconnection</td>
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<td>3: Actual Interchange</td>
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<td>5: Scheduled Inadvertent Payback</td>
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### INTERCHANGE DETAILS (All values in MWh)

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<td>2:</td>
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<td>Total</td>
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<td>3:</td>
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<td>Actual Interchange</td>
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<td>4:</td>
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<tr>
<td>5:</td>
<td></td>
<td>Scheduled Inadvertent Payback</td>
<td></td>
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<tr>
<td>6:</td>
<td>Inadvertent Interchange</td>
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### AREA INTERCHANGE CALCULATION

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<tbody>
<tr>
<td>7: Computed Frequency Deviation</td>
<td>Hz</td>
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<td></td>
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<td></td>
<td></td>
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<tr>
<td>8: Frequency Bias Setting</td>
<td>MW/0.1 Hz (negative value)</td>
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<td></td>
<td></td>
<td></td>
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<td></td>
<td></td>
</tr>
<tr>
<td>9: Bias Obligation</td>
<td>MWh Line 7 x Line 8 x 10.0</td>
<td></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>10: Unilateral Inadvertent Payback</td>
<td>MWh</td>
<td></td>
<td></td>
<td></td>
<td></td>
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</tr>
<tr>
<td>11: Adjusted Area Interchange Error</td>
<td>MWh Line 6 Total – Line 9 – Line 10</td>
<td></td>
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<td></td>
<td></td>
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</tbody>
</table>

### 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 (−).
North American Electric Reliability Council  
Area Interchange Error Survey  
Western Interconnection  

Form AIE 2

1. Date: __________________________________________  
Hr. Ending (PST/PDT): ____________________________  
Control Area: ________________________________  
Region: ________________________________

INTERCHANGE DETAILS (All values in MWh)

2. Control Area or Interconnection

3. Actual Interchange

4. Scheduled Interchange

5. Scheduled Inadvertent Payback

6. Inadvertent Interchange

AREA INTERCHANGE CALCULATION

7. Computed Frequency Deviation

7.5. Computed System Time Error

8. Frequency Bias Setting  
(−)

9. Frequency Bias Obligation

9.5. Time Error Bias Obligation

10. Unilateral Inadvertent Payback

11. Adjusted Area Interchange Error

MWh Line 6 Total – Line 9 – Line 9.5 – Line 10

<table>
<thead>
<tr>
<th></th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
<th>6</th>
<th>Total</th>
<th>Average</th>
</tr>
</thead>
</table>

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 (−).
*s is defined as 1 or 0 as explained on the following page.

AIE–9
January 1, 1992
Training Document Subsections

A. Frequency Response
   - Frequency Response Characteristic
   - Response to Internal and External Generation/Load Imbalances
   - Frequency Bias versus Frequency Response Characteristic (FRC)
   - Effects of a Disturbance on all CONTROL AREAS External to the Contingent CONTROL AREA
   - Effects of a Disturbance on the Contingent CONTROL AREA

B. Survey Procedures
C. Survey Review

This document includes the purpose and description of the Frequency Response Characteristic (FRC) Survey, describes the complete survey procedure including specific instructions to complete the survey form and discusses the use of survey results.

A. Frequency Response

Frequency Response Characteristic Surveys are conducted to determine the frequency response characteristic of a control area. Accurate measurement of system response is difficult unless the frequency deviation resulting from a system disturbance is significant. Therefore, surveys are usually requested when significant frequency deviations occur.

Disturbances can cause the frequency to increase from loss of load or decrease from loss of generation. Frequency Response Surveys may be requested for either event.

1. Frequency Response Characteristic. For any change in generation/load balance in the INTERCONNECTION, a frequency change occurs. Each CONTROL AREA in the INTERCONNECTION will respond to this frequency change through:

   • A load change that is proportional to the frequency change due to the load’s frequency response characteristic,¹ and

   • A generation change that is inverse to the frequency change due to turbine governor action. The net effect of these two actions is the CONTROL AREA’s response to the frequency change, that is, its frequency response characteristic. The combined response of all CONTROL AREAS in the INTERCONNECTION will cause the INTERCONNECTION frequency to settle at some value different from the pre-disturbance value. It will not return frequency to the pre-disturbance value because of the turbine governor droop characteristic. Frequency will remain different until the CONTROL AREA with the generation/load imbalance (referred to as the “Aontingent CONTROL AREA”) corrects that imbalance, thus returning the INTERCONNECTION frequency to its pre-disturbance value.

2. Response to Internal and External Generation/Load Imbalances. Most of a CONTROL AREA’s frequency response will be reflected in a change in its actual net interchange. By

¹Rotating (motor) and inductive loads are the predominating factor. Resistive loads do not change with changing frequency.
monitoring the frequency error (the difference between actual and scheduled frequency) and the
difference between actual and scheduled interchange and by using its response to frequency
deviation, a CONTROL AREA’S automatic generation control (AGC) can determine whether the
imbalance in load and generation is internal or external to its system. If internal, the CONTROL
AREA’S AGC should correct the imbalance. If external, the CONTROL AREA’S AGC should allow
its generator governors to continue responding through its frequency bias contribution until the
contingent CONTROL AREA corrects its imbalance, which should return frequency to its pre-
disturbance value.

3. Frequency Bias versus Frequency Response Characteristic (FRC). The CONTROL AREA
should set its bias to match its FRC. In doing so, the CONTROL AREA’S bias would exactly offset
the tie line flow error \( (N_{IA} - N_{IS}) \) of the ACE that results from governor action following a
frequency deviation on the INTERCONNECTION. The following sections 4 and 5 discuss the
effects of bias on control action and explain the importance of setting the bias equal to the
CONTROL AREA’S FRC. The discussion explains the control action on all CONTROL AREAS
external to the contingent CONTROL AREA (the CONTROL AREA that experienced the sudden
generation/load imbalance) and on the contingent CONTROL AREA itself. While this discussion
deals with loss of generation, it applies equally to loss of load, or any sudden contingency
resulting in a generation/load mismatch. Each CONTROL AREA’S frequency response will vary
with each disturbance because generation and load characteristics change continuously. This
discussion also assumes that the frequency error from 60 Hz was zero (all ACE values were zero)
just prior to the sudden generation/load imbalance.

For an explanation of the ACE equation, refer to the Area Interchange Error Training Document.

4. Effects of a Disturbance on all CONTROL AREAS External to the Contingent CONTROL
AREA. When a loss of generation occurs, an INTERCONNECTION frequency error will occur as
rotating kinetic energy from the generators is expended\(^2\). All CONTROL AREAS’ generator
governors will respond to the frequency error and increase the output of their generators
accordingly. This will cause a change in the CONTROL AREAS’ actual net interchange. In other
words, \( N_{IA} \) will be greater than \( N_{IS} \) for all but the contingent CONTROL AREA, and the result will
be a positive flow out of the non-contingent CONTROL AREAS.

If the CONTROL AREAS were using only tie line flow error (i.e., flat tie control ignoring the
frequency error), this non-zero ACE would cause their AGC to reduce generation until \( N_{IA} \) was
equal to \( N_{IS} \); ACE would then be zero. However, doing this would not help arrest
INTERCONNECTION frequency decline because the control areas would not be helping to
temporarily replace some of the generation deficiency in the INTERCONNECTION. With the tie-
line bias method, the CONTROL AREAS’ AGC should allow their governors to continue
responding to the frequency deviation until the contingent control area replaces the generation it
lost. The resulting tie flow error \( (N_{IA} - N_{IS}) \) will be counted as INADVERTENT INTERCHANGE.

In order for the AGC to allow governor action to continue helping in this way, a frequency bias is
added to the tie flow error in the ACE equation. This bias is equal in magnitude and opposite in
direction to the governor action and should be exactly equal to each CONTROL AREA’S frequency
response characteristic measured in MW/0.1 Hz. Then, when multiplied by the frequency error,
the bias should exactly counteract the tie flow error portion of the ACE calculation.

\(^2\)An amount of kinetic energy proportional to the power (generation) lost will be withdrawn from
the stored energy in the generator rotors throughout the Interconnection. Thus, Interconnection frequency
decreases proportionally.
In other words, bias contribution = $10\beta(f_AB/s)$. ACE will be zero, and AGC will not readjust generation.

The ACE equation now becomes:

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

If the bias setting is greater than the CONTROL AREA’S actual frequency response characteristic, then its AGC will increase generation beyond the governor response, which further helps arrest the frequency decline, but increases INADVERTENT INTERCHANGE. Likewise, if the bias setting is less than the actual FRC, its AGC will reduce generation, reducing the CONTROL AREA’S contribution to arresting the frequency change. In both cases, the control action is unwanted.

5. **Effects of a Disturbance on the Contingent CONTROL AREA.** In the contingent CONTROL AREA where the generation deficiency occurred, most of the replacement power comes from the INTERCONNECTION over its tie lines from the frequency bias contributions of the other CONTROL AREAS in the INTERCONNECTION. A small portion will be made up internally from the contingent CONTROL AREA’S own governor response (bias contribution). In this case, the difference between Ni_A and Ni_S for the contingent CONTROL AREA is much greater than its frequency bias component. Its ACE will be negative, and its AGC will begin to increase generation. *The contingent CONTROL AREA must take appropriate steps to reduce its ACE to zero within ten minutes of the contingency.* (Reference: Operating Criterion II.A.) The energy supplied from the INTERCONNECTION is posted to the contingent CONTROL AREA’S inadvertent balance, and must be paid back.
B. Survey Procedures

Frequency Response Characteristic Surveys will be conducted to compare each CONTROL AREA’s FRC with respect to its bias setting.

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, or in response to specific requests from members of the Subcommittee.

- As soon as possible after the survey period is chosen by the chairman, the chairman or vice chairman shall notify each appropriate Subcommittee member by letter of the survey date and time, the frequency points A, B, and C, frequency deviation, and date for the survey to be returned.
- Each Subcommittee member shall notify each reporting CONTROL AREA within the Region by written request. The Subcommittee member shall provide each CONTROL AREA a copy of the survey form “NERC Frequency Response Characteristic Survey.”
- Each reporting control area shall return one completed copy of the survey form and a copy of its frequency chart.
- Each Subcommittee member shall review the appropriate control area results and send the copies of survey form results to the NERC staff.
- The NERC staff shall combine the control area data into one report and send one copy to each Subcommittee member.
- Each Subcommittee member shall be responsible for reproducing and distributing the summary report within their Region.

2. Instructions for FRC Survey

The table is the Control Area Frequency Response Characteristic Survey form.

A sample frequency chart is shown in Figure 1 with points A, B, and C labeled. Point A represents the interconnected system frequency immediately before the disturbance. Point B represents the interconnected system frequency at the point immediately after the frequency stabilizes due to governor action but before the contingent control area takes corrective AGC action. Point C represents the interconnected system frequency at its maximum deviation due to the loss of rotating kinetic energy from the turbine generators.

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

Line 1: Enter the date and time of survey period (this information is provided by the RESOURCES SUBCOMMITTEE member’s survey request) and the name of the control area.
B. Survey Procedures

Line 2: Enter the net interchange of the control area immediately before the survey period (corresponding to Point A). Sign convention for net power into a CONTROL AREA is negative (−), and net power out of a control area is positive (+).

Line 3: Enter the net interchange of the control area immediately after the survey period (corresponding to Point B). Use the same sign convention as Line 2.

Line 4: Enter the change in net interchange of the CONTROL AREA. Line 4 = Line 3 – Line 2. For a disturbance that causes the frequency to decrease, this value should be positive except for the contingent CONTROL AREA, in which case it is negative.

Line 5: If the control area completing the survey suffered the loss, enter the load or generation lost by the control area. Otherwise, leave this line blank. Sign convention for generation loss is negative (−) and for load loss is positive (+).

Line 6: Enter the control area response. This value is (Line 4 – Line 5).

Line 7: Enter the change in interconnected system frequency as specified in the letter of transmittal.

Line 8: Enter the frequency response characteristic of the CONTROL AREA based on the change in interconnected system frequency. This value is:

\[
FRC = \frac{\text{Line 6}}{(\text{Line 7})10.0}
\]

(The factor of 10.0 is used to change the units to MW/0.1 Hz.) This value approximates the frequency response of the control area for this disturbance.

Line 9: Enter the frequency bias setting of the CONTROL AREA.

Line 10: Enter the CONTROL AREA’s net system load immediately before the disturbance.

Line 11: Enter the CONTROL AREA’s total capacity synchronized to the INTERCONNECTION immediately before the disturbance. Jointly owned units should be reported in their entirety by the CONTROL AREA in which they are located.

Lines 12, 13, and 14:

Enter the frequency values you observed from the frequency chart for Points A, B, and C, respectively.
C. Survey Review

Each NERC RESOURCES SUBCOMMITTEE member shall analyze the survey results of the CONTROL AREAS within their Region. The survey data received on the survey form shall be reviewed for uniformity, completeness, and compliance to the instructions. The NERC Resources Subcommittee will review the total frequency response for the total INTERCONNECTION surveyed to ensure adequate frequency bias exists to maintain the scheduled frequency.
## North American Electric Reliability Council
### Frequency Response Characteristic Survey

**Form FRC 1**

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<th>1. Date</th>
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### AREA FREQUENCY RESPONSE CALCULATION

2: Actual Net Interchange Immediately Before Disturbance (Point A)*

3: Actual Net Interchange Immediately After Disturbance (Point B)*

4: Change in Net Interchange

5: Load (+) or Generation (−) Lost Causing the Disturbance

6: Control Area Response

7: Change in Interconnection Frequency from Point A to Point B

8: Frequency Response Characteristic

### OTHER INFORMATION

9. Frequency Bias Setting

10. Net System Demand Immediately Before Disturbance (Point A)

11. Synchronized Capacity Immediately Before Disturbance (Point A)

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</thead>
<tbody>
<tr>
<td>Hz</td>
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</table>

**Notes:**

Net power delivered out of a control area (over-generation) is positive (+).
Net power received into a control area (under-generation) is negative (−).

*CONTROL AREAS that have a Net Tie Deviation From Schedule Recorder should obtain these values from that device.*
A. Introduction

The purpose of this document is to explain inadvertent interchange (inadvertent) accounting. Included within this document are accounting practices that every control area within the North American Electric Reliability Council shall follow. These practices provide a method for isolating and eliminating the source(s) of accounting errors. They may also be used as an aid in identifying the poor control performance that contributes to inadvertent accumulations.

Additional information concerning inadvertent may be found in the NERC Operating Manual under Operating Policy 1F., Inadvertent Interchange

Simple accounting errors (value or sign) made while recording actual net interchange or scheduled net interchange become operating problems as soon as they become a part of hourly accounting. This occurs because the system dispatcher may be influenced to bilaterally or unilaterally pay back inadvertent or offset a schedule setter to correct a perceived metering error. Viewed from a total interconnected network (Interconnection) perspective, when inadvertent no longer sums to zero due to accounting errors subsequent unilateral pay backs to correct for the “perceived” inadvertent will cause a generation surplus or deficiency on the interconnection. Ultimately this shows up in the form of a continuously recurring time error.

B. Definitions

Adjacent Control Areas: Any control areas within an Interconnection sharing a common tie line or metering point.

Hourly MWh Metered Values: MWh data accumulated (whether by telemetry, telephone, direct meter readings, etc.) on an hourly basis.

Adjustments For Error: Either meter errors, absence of metering data due to communication failure or missing data for whatever cause. The important point is that such adjustments are made between control areas involved in the same manner and at the same times in opposite directions.
C. **Interchange Accounting**

1. **Accounting For Interchange.** Accounting for energy between control areas residing within the same Interconnection is both simple and complicated. In theory, and in accordance to NERC Guides, inadvertent interchange is the difference between actual net interchange and scheduled net interchange over a given period, usually an hour. Mathematically it is the time integral of the deviation of a control area's actual net interchange from its scheduled net interchange:

   \[ NI_I = NI_A - NI_S \]

   Where,

   \( NI_I \) is inadvertent interchange. In accordance with NERC convention, negative values of inadvertent interchange denote a condition of undergeneration and positive values denote overgeneration.

   \( NI_A \) is actual net interchange. It is the algebraic sum of the hourly integrated energy on a control area's tie lines including pseudo-ties for any jointly owned generating units. Actual net interchange is positive for power leaving the system and negative for power entering.

   \( NI_S \) is scheduled net interchange. It is defined as the mutually prearranged net energy on a control area's tie lines including dynamic schedules or fixed schedules for any jointly owned generating units. Scheduled net interchange is positive for power scheduled to be delivered from the system and negative for power scheduled to be received into the system.

2. **Actual Net Interchange Energy Accounting.** Actual net interchange (metered interchange) between two adjacent control areas over a common tie line is accounted for at a specific point in the line. Furthermore, both control areas shall agree on the amount of energy flow through this point, including any pseudo-tie flows for jointly owned generating units that may exist between the two control areas. Therefore, the sum of metered energy accounted by both control areas over this tie line nets to zero. Since this is true for all control areas within the same Interconnection, the algebraic sum of all metered energy within the same Interconnection is also zero.

3. **Scheduled Net Interchange Energy Accounting.** All scheduled net interchange (and schedule changes) shall be agreed upon between the control areas involved prior to implementation in regard to magnitude, rate of change, and common starting time. Dynamic schedules and fixed schedules for jointly owned generating units between control areas should be agreed to on an hour-by-hour basis, and included as scheduled interchange. Since every interchange schedule is agreed to by all delivering and receiving control areas within an Interconnection, the algebraic sum of all scheduled net interchange is also zero.

4. **Inadvertent Interchange Energy Accounting.** As stated previously, inadvertent interchange is the difference between actual net interchange and scheduled net interchange over a given period. Since the algebraic sum of all actual net interchange and the algebraic sum of all scheduled net interchange for any given period is zero within an Interconnection, the sum of all inadvertent interchange is also zero.
D. **Inadvertent Interchange Energy Accounting Practices**

The practices set forth in this section outline the methods and procedures required to reconcile energy accounting and inadvertent interchange balances.

In order for a control area to properly monitor and account for inadvertent interchange, it shall adhere to the NERC Operating Policies.

1. **Accounting Procedures**

   1.1. **On-Peak and Off-Peak Accounting Periods.** Each control area is obligated to maintain its inadvertent interchange accounting within two periods, namely, on-peak and off-peak (refer to Appendix A).

   1.2. **Schedules.** All hourly schedules and schedule changes shall be agreed upon between the control areas involved prior to implementation in regard to magnitude, rate of change, and common starting time.

   1.3. **Dynamic Schedules.** Dynamic schedules integrated on an hourly basis shall be agreed upon by the control areas involved subsequent to the hour, but in such a manner as not to impact inadvertent accounts. This is accomplished by ensuring that the hourly actual and scheduled interchange quantities agree between all delivering and receiving parties.

   1.4. **Daily Accounting.** Each control area shall agree with adjacent control areas on the actual net interchange (MWh) and scheduled net interchange (MWh) at least once each day for on-peak and off-peak periods.

   1.5. **Monthly Accounting.** Having agreed to the on-peak and off-peak period accumulations on a daily basis, adjacent control areas shall verify that the accumulated values for the month balance.

   1.6. **Adjustments for Error.** Adjustments shall be made at least once each month to correct for differences between hourly MWh meter totals and the totals derived from register readings at the tie line meters.

      1.6.1 **Differences.** Adjacent control areas shall agree upon the difference determined above and assign this correction to the proper on-peak and off-peak period at the same times and in equal quantities in the opposite directions.

      1.6.2 **Adjustments.** Any adjustments necessary due to known metering errors, franchised territories, transmission losses or other special circumstances shall be made in the same manner.

2. **Accounting Periods For Control Areas Not Using Daylight Savings Time**

Some control areas (and states) do not recognize Daylight Saving Time. Where this is the case, inadvertent interchange accounting periods must be shifted in order to remain coordinated with the rest of the control areas that do recognize Daylight Saving Time.
During the shift to Daylight Saving Time, control areas not recognizing Daylight Saving Time should change their accounting periods as follows:

2.1. For the Eastern and ERCOT Interconnections

2.1.1. Atlantic Time Zone. If the control area is in the Atlantic Time Zone, then the on-peak hours change from Hour Ending (HE) 0900–HE 2400 AST Monday through Saturday to HE 0800–HE 2300 AST Monday through Saturday. Similarly, the off-peak hours change from HE 0100–HE 0800 AST Monday through Saturday to HE 2400–HE 0700 AST Monday through Saturday.

2.1.2. Eastern Time Zone. If the control area is in the Eastern Time Zone, then the on-peak hours change from Hour Ending (HE) 0800–HE 2300 EST Monday through Saturday to HE 0700–HE 2200 EST Monday through Saturday. Similarly, the off-peak hours change from HE 2400–HE 0700 EST Monday through Saturday to HE 2300–HE 0600 EST Monday through Saturday.

2.1.3. Central Time Zone. If the control area is in the Central Time Zone, then the on-peak hours change from HE 0700–HE 2200 CST Monday through Saturday to HE 0600–HE 2100 CST Monday through Saturday. Similarly, the off-peak hours change from HE 2300–HE 0600 CST Monday through Saturday to HE 2200–HE 0500 CST Monday through Saturday.

2.2. For the Western Interconnection

2.1.1. Central Time Zone. If the control area is in the Central Time Zone, then the on-peak hours change from HE 0900–HE 2400 CST Monday through Saturday to HE 0800–HE 2300 CST Monday through Saturday. Similarly, the off-peak hours change from HE 0100–HE 0800 CST Monday through Saturday to HE 2400–HE 0700 CST Monday through Saturday.

2.1.2. Mountain Time Zone. If the control area is in the Mountain Time Zone, then the on-peak hours change from HE 0800–HE 2300 MST Monday through Saturday to HE 0700–HE 2200 MST Monday through Saturday. Similarly, the off-peak hours change from HE 2400–HE 0700 MST Monday through Saturday to HE 2300–HE 0600 MST Monday through Saturday.

2.1.3. Pacific Time Zone. If the control area is in the Pacific Time Zone, then the on-peak hours change from HE 0700–HE 2200 PST Monday through Saturday to HE 0600–HE 2100 PST Monday through Saturday. Similarly, the off-peak hours change from HE 2300–HE 0600 PST Monday through Saturday to HE 2200–HE 0500 PST Monday through Saturday.
3. Accounting For Inadvertent Interchange Over DC Tie Lines Between Separately Synchronous Interconnections

For the purpose of NERC inadvertent interchange accounting, there shall be no contribution to a control area’s inadvertent accumulation due to a dc tie connecting adjacent control areas operating in separate Interconnections.

4. Summary Of Accounting Rules

4.1. Summation of scheduled net interchange. The summation of all scheduled net interchange within an Interconnection shall total zero for any period of time.

4.2. Summation of actual net interchange. The summation of all actual net interchange within an Interconnection shall total zero for any period of time.

4.3. Summation of inadvertent interchange for Interconnection. The summation of all inadvertent interchange within an Interconnection shall total zero for any period of time.

5. Accounting Examples

Daily, total all actual net interchange accumulated during the on-peak and off-peak periods. Do the same with the scheduled net interchange. By period, subtract the totaled scheduled net interchange from the totaled actual net interchange. This will yield on-peak and off-peak inadvertent accumulations for the day. The addition of these two accumulations is the control area’s inadvertent interchange accumulation for the day. All control areas are required to keep an accurate, continuous record of their current balances of on-peak, off-peak, and (net) inadvertent for the day, month, and accumulative to date.

As an example, the Western Interconnection’s month-end inadvertent interchange report for February 1995 is included on the following page. Every control area in the Interconnection is included. The sum of each period’s inadvertent totals to zero.

An example of an individual control area’s month-end data submittal to its Performance Subcommittee representative is also included.

E. Interchange Accounting Practices for Jointly Owned Generating Units

[Appendix 1A – The Area Control Error Equation, Section B – Jointly Owned Units]

1. Jointly Owned Generating Units. It is assumed that every jointly owned generating unit resides within a host control area. It is also assumed that every owner will treat its share of the unit as generation within its own control area. Recipients may account for their share of unit output by one of three methods. All participants in a jointly owned generating unit must agree with the host control area on which of these methods is to be used:

1.1 Scheduled interchange. The host control area and the recipient control area agree on a pre-determined, fixed schedule. Generally, these schedules are manually altered to adjust
for unplanned operating conditions at the unit, e.g., if the unit unexpectedly trips out of service.

1.2 **Dynamically scheduled interchange.** The host control area and recipient control area share an electronic signal indicating the real-time power transfer from the unit to the recipient. The host control area and recipient control areas see this transfer as a continually changing schedule between the two control areas. It is recommended that after-the-fact adjustments for month-end accumulators or erroneous signals be corrected in future operating periods and not be back-corrected.

1.3 **As a pseudo-tie.** The host control area and the recipient control area share an electronic signal indicating the real-time energy transfer from the unit to the recipient. The host control area and the recipient control area see this transfer as continually changing metered interchange between the two control areas. It is recommended that after-the-fact adjustments for month-end accumulators or erroneous signals be corrected in future operating periods and not be back-corrected.

F. **Interchange Accounting Practices for Regulation Service**

If a control area provides regulation service for another control area, it generally will occur in one of two ways:

1. **Supplemental Regulation.** The control area providing supplemental regulation service will receive a signal representing all or a portion of the other control area’s ACE. Control areas participating in supplemental regulation are not required to make any changes to their accounting systems. Supplemental regulation can be implemented as a dynamic schedule or a pseudo-tie. Both control areas need to use the same method.

2. **Overlap Regulation.** The control area providing overlap regulation service will include all of the other control area’s tie lines and schedules in its (the providing control area’s) AGC equation. Entities participating in overlap regulation are required to notify the control area providing the regulation of all interchange schedules with other control areas before they are implemented. This is necessary to maintain the integrity of central coordinated control. Ultimate responsibility for energy accounting lies solely with the control area providing the overlap regulation service.
## SUMMARY of WESTERN INADVERTENT INTERCHANGE ENERGY thru FEBRUARY 1995 -- Central Standard Time

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INAD-7

May 24, 1994
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|                                | ON-PEAK  | OFF-PEAK  | NET      |
|                                | Previous Accumulation | 181 | -40      |
|                                | Net for Month | 64  | 936      |
|                                | Carried Forward | 117 | 896      |
DATA
## Control Areas

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Friday, May 21, 2004
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### SERC

**Region** | **Control Area** | **Acronym**
--- | --- | ---
| **Number of Control Areas: 22** | | 
Alabama Electric Cooperative, Inc. | AEC | 
Associated Electric Cooperative, Inc. | AECl | 
Batesville Control Area | BCA | 
Carolina Power & Light Company - CPLE | CPL | 
Carolina Power & Light Company - CPLW | CPLW | 
DECA, LLC - Enterprise | DEEM | 
DECA, LLC - Murray 230 kV | DMT | 
DECA, LLC - North Little Rock | DENL | 
DECA, LLC - Sandersville | DESG | 
Dominion Virginia Power | VAP | 
Duke Energy Corporation | DUK | 
Entergy | EES | 
Louisiana Generating, LLC | LAGN | 
Santee Cooper | SC | 
South Carolina Electric & Gas Company | SCEG | 
South Mississippi Electric Power Association | SMEE | 
Southeastern Power Administration | SETH | 
Southeastern Power Administration | SEHA | 
Southeastern Power Administration | SERU | 
Southern Company Services, Inc. | SOC | 
Tennessee Valley Authority ESO | TVA | 
Yadkin, Inc. | YAD | 

### SPP

**Region** | **Control Area** | **Acronym**
--- | --- | ---
| **Number of Control Areas: 18** | | 
Aquila Networks - MPS | MPS | 
Aquila Networks - WPK | WPEK | 
Board of Public Utilities | KACY | 
Central and Southwest | CSWS | 
City of Independence P&L Dept. | INDN | 
Cleco Power LLC | CLEC | 
Empire District Electric Co., The | EDE | 
Grand River Dam Authority | GRDA | 
Kansas City Power & Light, Co | KCPL | 
Lafayette Utilities System | LAFA | 
Louisiana Energy & Power Authority | LEPA | 
McClain | MCLN | 
Oklahoma Gas and Electric | OKGE | 
Southwestern Power Administration | SPA | 
Southwestern Public Service Company | SPS | 
Sunflower Electric Power Corporation | SECI | 
Western Farmers Electric Cooperative | WFEC | 
Western Resources dba Westar Energy | WR |
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**Total Number of Control Areas: 138**
## 2004 CPS2 Bounds

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<th>Bias/Load (%)</th>
<th>Bias/Total Bias (%)</th>
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| FRCC                  |                      |               |                     |          |               |
|-----------------------|                      |               |                     |          |               |
| City of Homestead | 71 | 1 | 1.41 | 0.02 | 7.57 |
| City of Tallahassee | 588 | 9 | 1.53 | 0.14 | 22.70 |
| Florida Municipal Power Pool | 3,300 | 33 | 1.00 | 0.51 | 43.46 |
| Florida Power & Light | 20,222 | 202 | 1.00 | 3.12 | 107.53 |
| Florida Power Corporation | 8,684 | 87 | 1.00 | 1.34 | 70.57 |
| Gainesville Regional Utilities | 467 | 6 | 1.28 | 0.09 | 18.53 |
| JEA | 3,083 | 31 | 1.01 | 0.48 | 42.13 |
| Reedy Creek Improvement District | 187 | 2 | 1.07 | 0.03 | 10.70 |
| Seminole Electric Cooperative | 3,484 | 16 | 0.46 | 0.25 | 30.26 |
| Tampa Electric Company | 4,282 | 43 | 1.00 | 0.66 | 49.61 |
| Utilities Commission, City of New Smyrna Beach | 92 | 1 | 1.09 | 0.02 | 7.57 |
| **FRCC Totals:** | 44,460 | 431 | 0.97 | 6.66 | |

* Indicates Installed Capacity of Generation Only Control Area and Is Not Included In the Estimated Peak Demand of the Region.

** The L10 of a variable bias Control Area is calculated using the average bias as submitted to NERC for traditional Control Areas and by using 1% of installed capacity for Generation Only Control Areas. The actual L10 used for Control Area performance reporting will differ based upon the requirements for each report.
## 2004 CPS2 Bounds

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<th>MAAC</th>
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<th>Freq. Bias (MW/.1Hz)</th>
<th>Bias/Load (%)</th>
<th>Bias/Total Load (%)</th>
<th>L10 (MW)</th>
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<th>Bias/Total Load (%)</th>
<th>L10 (MW)</th>
<th>Variable Bias ?</th>
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<table>
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<th>MAPP</th>
<th>Name</th>
<th>Est. Peak Demand (MW)</th>
<th>Freq. Bias (MW/.1Hz)</th>
<th>Bias/Load (%)</th>
<th>Bias/Total Load (%)</th>
<th>L10 (MW)</th>
<th>Variable Bias ?</th>
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</table>

* Indicates Installed Capacity of Generation Only Control Area and is not included in the estimated peak demand of the region.

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Monday, March 01, 2004
<table>
<thead>
<tr>
<th>NPCC</th>
<th>Est. Peak Demand (MW)</th>
<th>Freq. Bias (MW/.1Hz)</th>
<th>Bias/Load (%)</th>
<th>Bias/Total Bias (%)</th>
<th>L10 (MW)</th>
<th>Variable Bias</th>
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<table>
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<th>SERC</th>
<th>Est. Peak Demand (MW)</th>
<th>Freq. Bias (MW/.1Hz)</th>
<th>Bias/Load (%)</th>
<th>Bias/Total Bias (%)</th>
<th>L10 (MW)</th>
<th>Variable Bias</th>
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</tbody>
</table>

* Indicates Installed Capacity of Generation Only Control Area and Is Not Included In the Estimated Peak Demand of the Region.

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### 2004 CPS2 Bounds

<table>
<thead>
<tr>
<th>SPP</th>
<th>Est. Peak Demand (MW)</th>
<th>Freq. Bias (MW/.1Hz)</th>
<th>Bias/Load (%)</th>
<th>Bias/Total Bias (%)</th>
<th>L10 (MW)</th>
<th>Variable Bias</th>
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**SPP Totals:**
- Est. Peak Demand (MW): 40,267
- Freq. Bias (MW/.1Hz): 458
- Bias/Load (%): 1.14
- L10 (MW): 7.07

### Hydro Quebec Interconnection

<table>
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<th>Est. Peak Demand (MW)</th>
<th>Freq. Bias (MW/.1Hz)</th>
<th>Bias/Load (%)</th>
<th>L10 (MW)</th>
<th>Variable Bias</th>
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<tbody>
<tr>
<td>Hydro-Quebec, TransEnergie</td>
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</table>

**NPCC-HQ Totals:**
- Est. Peak Demand (MW): 34,980
- Freq. Bias (MW/.1Hz): 624
- Bias/Load (%): 1.78
- L10 (MW): 100.00

### ERCOT Interconnection

<table>
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<th>ERCOT</th>
<th>Est. Peak Demand (MW)</th>
<th>Freq. Bias (MW/.1Hz)</th>
<th>Bias/Load (%)</th>
<th>L10 (MW)</th>
<th>Variable Bias</th>
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<tbody>
<tr>
<td>ERCOT ISO</td>
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<td>533 - 604**</td>
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<td>100.00</td>
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**ERCOT Totals:**
- Est. Peak Demand (MW): 59,080
- Freq. Bias (MW/.1Hz): 562
- Bias/Load (%): 0.95
- L10 (MW): 100.00

**ERCOT Interconnection Totals:**
- Est. Peak Demand (MW): 59,080
- Freq. Bias (MW/.1Hz): 562
- Bias/Load (%): 0.95
- L10 (MW): 100.00

---

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### 2004 CPS2 Bounds

<table>
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<tr>
<th></th>
<th>Est. Peak Demand (MW)</th>
<th>Freq. Bias (MW/.1Hz)</th>
<th>Bias/Load (%)</th>
<th>Bias/Total Bias (%)</th>
<th>L10 (MW)</th>
<th>Variable Bias ?</th>
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* Indicates Installed Capacity of Generation Only Control Area and Is Not Included In the Estimated Peak Demand of the Region.

** The L10 of a variable bias Control Area is calculated using the average bias as submitted to NERC for traditional Control Areas and by using 1% of installed capacity for Generation Only Control Areas. The actual L10 used for Control Area performance reporting will differ based upon the requirements for each report.
## 2004 CPS2 Bounds

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* Indicates Installed Capacity of Generation Only Control Area and Is Not Included In the Estimated Peak Demand of the Region.

** The L10 of a variable bias Control Area is calculated using the average bias as submitted to NERC for traditional Control Areas and by using 1% of installed capacity for Generation Only Control Areas. The actual L10 used for Control Area performance reporting will differ based upon the requirements for each report.
Dynamic Transfer Reference Document

Version 1

March 25, 2004
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Overview

The purpose of this document is to provide guidance to the industry on the responsibilities, requirements, and expectations placed upon parties involved in establishing a dynamic transfer. The white paper is needed to bring standardization to the industry regarding implementation and operation of dynamic transfers. The paper may be used to help determine how to design and implement dynamic transfer control schemes to meet the implementation requirements for a specific set of operating conditions, system requirements, Control Area-related jurisdictional responsibilities, and commercial arrangements (to include providing of Control Area services).

There is not a consistent set of guidelines for dynamic transfers and NERC policies do not address the implementation of dynamic transfers. Accordingly, various interpretations exist within the industry on how to implement, operate, and account for dynamic transfers. Common definitions and a minimum set of requirements should ensure the future reliable implementation of dynamic transfers.

The intent of this white paper is to provide guidelines for future implementations of dynamic transfers. To the extent that dynamic transfers are compliant with all applicable NERC policies, it is neither within the scope of this white paper nor the intention of the Dynamic Transfer Task Force to force entities to have to modify any existing dynamic transfers, particularly those used to implement grandfathered contractual arrangements.

Dynamic Transfer is a term that refers to methods by which the control response to loads or generation is assigned, on a real-time basis, from the CONTROL AREA to which such loads or generation are electrically interconnected (Native Control Area) to another CONTROL AREA (Attaining Control Area) on a real-time basis. Depending on desired implementation of system control as well as various contractual, jurisdictional and regulatory responsibilities between the Native and Attaining Control Areas, one of the two methods of the Dynamic Transfer may be employed: 1) Dynamic Schedule, or 2) Pseudo-Tie:

DYNAMIC SCHEDULE. A telemetered reading, or value that is updated in real-time and used as a schedule in the AGC/ACE equation of the affected Control Areas and the integration of which is treated as a schedule for interchange accounting purposes.

PSEUDO-TIE. A telemetered reading, or value that is updated in real time, representative of generation or load assigned dynamically between control areas and used as a tie line flow in the affected control areas’ AGC/ACE equation, but for which no physical CONTROL AREA tie actually exists. To the extent that no associated energy metering equipment exists, the integration of the telemetered real time signal is used as a metered MWh value for interchange accounting purposes.

Integration in the terms above means the value could be mathematically calculated or determined mechanically with a metering device.

The key difference between PSEUDO-TIES and DYNAMIC SCHEDULES from the system control point of view is in how the transfer is implemented in each CONTROL AREA’S ACE equations and in the associated energy accounting processes. By definition, PSEUDO-TIES are accounted for by all parties as ACTUAL INTERCHANGE and DYNAMIC SCHEDULES are accounted for as SCHEDULED INTERCHANGE.

NOTE: In this document, the use of the term CONTROL AREA is intended to be consistent with that defined in the NERC operating policies.
The particular Dynamic Transfer method to be utilized for a specific operating arrangement may be dependent upon on some or all of the following:

- Desired service(s) to be provided
- The capability to capture the dynamic transfer in system models
- Responsibility for forecasting load
- Responsibility for providing unit commitment and maintenance information
- EMS capability

It is the obligation of each CONTROL AREA to fulfill its commitment to the INTERCONNECTION and not burden other CONTROL AREAS in the INTERCONNECTION. The use of a dynamic transfer does not in any way diminish this responsibility.

- Before implementing the dynamic transfer, all parties to the dynamic transfer must agree on all implementation issues.
- Any errors resulting from an improperly implemented or operated dynamic transfer (including inadvertent accumulations) must be resolved between the involved parties and should not be in any way passed to the INTERCONNECTION.
- Dynamic transfers should NOT include any control offsets that are not explicitly compliant with the requirements set forth in NERC policies (e.g., unilateral inadvertent payback, Western Interconnection automatic time error control, etc.).
- Each CONTROL AREA must ensure that the dynamic transfer of load or generation is coordinated with the RELIABILITY COORDINATOR(S) that have responsibility over the Native, Attaining and INTERMEDIARY CONTROL AREAS so that the particular method of dynamic transfer can be considered in the system modeling of the generation or load affected, and necessary data provision requirements are met. [See also, Appendix 4B – Electric System Security Data.]
- Applicable tariff requirements of all involved, or affected, transmission providers and/or Control Areas must be met (this includes proper handling and accounting for energy losses).
- If the dynamic transfer includes a pre-arranged calculated assistance (or distribution of responsibility) between the Native CONTROL AREA and the Attaining CONTROL AREA for recovery from the loss of generation, then both CONTROL AREAS are responsible for ensuring that their respective DCS compliance reporting requirements are met in accordance with NERC Policy 1.
A. Dynamic Schedule

A DYNAMIC SCHEDULE is implemented as an INTERCHANGE TRANSACTION that is modified in real-time to transfer time-varying amounts of power between CONTROL AREAS. A DYNAMIC SCHEDULE typically does not provide for change in Control Area jurisdiction (Native Control Area continues exercising operational jurisdiction over, and provides basic Control Area services to, the dynamically scheduled resources) DYNAMIC SCHEDULES are typically utilized in, but not limited, to the following scenarios:

- Transfer the entire, or a portion of, actual output of a specific generator(s) to another CONTROL AREA as it is generated in real-time,
- enable resources in one CONTROL AREA to provide the real-time power requirements for a load in another CONTROL AREA, or
- enable generators and/or loads in one CONTROL AREA to supply one or more Interconnected Operations Services to generators and/or loads in another CONTROL AREA, AND
- provide a mechanism for reserve sharing.

DYNAMIC SCHEDULES are to be accounted for as INTERCHANGE SCHEDULES by the SOURCE, SINK, and CONTRACT INTERMEDIARY CONTROL AREAS, both in their respective ACE equations and throughout all of their energy accounting processes. 1. Requirement to incorporate into the CICA’s ACE is subject to regional procedures.

All DYNAMIC SCHEDULES used to assign the control of generation, loads or resources from one CONTROL AREA to another must meet the following requirements:

1. Telemetry

1.1. Pursuant to NERC Policy 1, Section E, 4.1, 4.4, 4.5, 4.7, 4.8, and 5, appropriate telemetry must be in place and incorporated by all affected CONTROL AREAS.

2. Transmission Service

2.1. Prior to implementation of the dynamic transfer of load or generation, it is the obligation of each involved CONTROL AREA to ensure that the dynamic transfer is implemented such that the tariff requirements of the applicable TRANSMISSION PROVIDER(S) are met, including applicable ancillary services and provision of losses.

2.2. If transmission service between the SOURCE and SINK CONTROL AREAS is curtailed then the allowable range of the magnitude of the schedules between them, including DYNAMIC SCHEDULES, may have to be curtailed accordingly.

3. System Modeling

3.1. It is the obligation of each CONTROL AREA to ensure that the dynamic transfer of load or generation through a dynamic schedule is coordinated with the RELIABILITY COORDINATOR(S) with responsibility over the Native, Attaining and CONTRACT INTERMEDIARY CONTROL AREAS so that the dynamic schedule can be properly implemented in the system modeling of the affected generation or load, and necessary data provision requirements are met. Coordination must include tagging of the resultant
scheduled interchange for use by other TRANSMISSION PROVIDERS and CONTROL AREAS for system security analysis and calculation of ATC. [See also, Appendix 4B – Electric System Security Data.]

3.2. When a DYNAMIC SCHEDULE is used to serve load within another CONTROL AREA, it is the responsibility of the CONTROL AREA where the load is electrically connected (Native Control Area) to include that load in its CONTROL AREA load forecast and any subsequent reporting as needed. This is necessary, as the system models must adequately capture the projected demand on the system (load forecast), and the projected supply (provided by the electronic tagging system).

4. Dynamic Schedule Coordination and Scheduling

4.1. Implementation of a DYNAMIC SCHEDULE must be through the use of an INTERCHANGE TRANSACTION between CONTROL AREAS. As such, all DYNAMIC SCHEDULES must be implemented in accordance with NERC Policy 3 including the tagging of all Dynamic Schedules.

4.2. Energy exchanged between the SOURCE, SINK and INTERMEDIARY CONTROL AREAS as a dynamic schedule is the metered or calculated (obtained by the Integration of the DYNAMIC SCHEULE signal over the operating hour) energy for the loads and/or resources for the hour. Agreements must be in place, with the applicable transmission providers, to address the physical or financial provision of transmission losses.

4.3. It is the responsibility of the Native Control Area to ensure that agreements are in place defining the responsibility for providing applicable Ancillary/Interconnected Operations Services.

5. Trouble Response

5.1. The Native Control Area, Attaining Control Area, and INTERMEDIARY CONTROL AREAS shall agree before implementation of the DYNAMIC SCHEDULE on a plan for how the CONTROL AREAS will operate during a loss of the DYNAMIC SCHEDULE telemetry signal such that all involved CONTROL AREAS are using the same value. The CONTROL AREAS may agree to hold the last known good value, use an average load profile value, or have one party provide the other with a manual override value at some acceptable frequency of update.

5.2. The Native Control Area, Attaining Control Area and INTERMEDIARY CONTROL AREAS should agree before implementation of the DYNAMIC SCHEDULE upon a plan for how the load will be served during abnormal system conditions including periods of time when the interconnection between them is lost. The Native Control Area, Attaining Control Area and INTERMEDIARY CONTROL AREAS shall also agree before implementation of the DYNAMIC SCHEDULE as to how the generation serving the DYNAMIC SCHEDULE will respond during abnormal system conditions, including periods of time when the interconnection between them is lost.

6. Compliance with NERC Operating Policy

6.1. The implementation of a dynamic transfer may confer upon the Attaining Control Area additional responsibilities for compliance with NERC Operating Policy for the load or generation that has been transferred.
See Appendix C “ACE Equation Modifications for Dynamic Schedule”
B. Pseudo-Tie

PSEUDO-TIES are often employed to assign loads and/or generators from the CONTROL AREA to which they are physically connected into a CONTROL AREA, which has effective operational control of them. Thus, PSEUDO-TIES provide for change of control area jurisdiction from the Native to the Attaining control Area and at the same time make the Attaining Control Area provider of control area services. This methodology is also referred to as “AGC Interchange” or “Non-Contiguous Pool Tie.” In practice, PSEUDO-TIES may be implemented based upon metered or calculated values. All CONTROL AREAS involved account for the power exchange and associated transmission losses as ACTUAL INTERCHANGE between the CONTROL AREAS, both in their ACE equations and throughout all of their energy accounting processes.

All PSEUDO-TIES used to assign generation, loads or resources from the Native Control Area to the Attaining Control Area must meet the following requirements:

1. Telemetry
   1.1. Pursuant to NERC Policy 1, Section E, 4.1, 4.4, 4.5, 4.7, 4.8, and 5, appropriate telemetry must be in place and incorporated by all affected CONTROL AREAS.

2. Transmission Service
   2.1. Prior to implementation of the dynamic transfer of load or generation, it is the obligation of each involved CONTROL AREA to ensure that the dynamic transfer is implemented such that the tariff requirements of the applicable TRANSMISSION PROVIDER(S), including applicable ancillary services and provision of losses, are met.

   2.2. If transmission service between the Native and Attaining Control Areas is curtailed then the allowable range of the magnitude of the PSEUDO-TIES between them must be limited accordingly to these constraints.

3. System Modeling
   3.1. The assignment of load or generation into the control response of another CONTROL AREA must be appropriately captured in the IDC and security analysis system models of other TRANSMISSION PROVIDERS, CONTROL AREAS, and RELIABILITY COORDINATORS. It is the obligation of each CONTROL AREA to ensure that the dynamic transfer of load or generation is coordinated with the RELIABILITY COORDINATOR(S) that have responsibility over the Native, Attaining and CONTRACT INTERMEDIARY CONTROL AREAS so that the method of dynamic transfer can be properly implemented in the system modeling of the generation or load affected, and necessary data provision requirements are met. [See also, Appendix 4B – Electric System Security Data.]

   3.2. It is the responsibility of the Attaining Control Area dynamically transferring load into its effective boundaries through a PSEUDO-TIE to ensure that load forecasts and subsequent CONTROL AREA reporting reflect the load incorporated within its CONTROL AREA boundaries.

---

1 References to the IDC may not apply to ERCOT or WECC.
3.3. If the reliability impact of the PSEUDO-TIE cannot be accurately captured in the IDC and the security analysis system models of other TRANSMISSION PROVIDERS, CONTROL AREAS, and RELIABILITY COORDINATORS, the parties must implement the dynamic transfer either through use of a DYNAMIC SCHEDULE, or through a combined implementation of PSEUDO-TIE and DYNAMIC SCHEDULE where the load or generation within the Native Control Area is separately modeled in the IDC. (See footnote 2.)

4. Pseudo-Ties Coordination and Scheduling

4.1. Subsequent to moving load or resources into an Attaining Control Area through PSEUDO-TIES, all INTERCHANGE TRANSACTIONS or other energy transfers to the loads or from the resources must be coordinated through the operator of the Attaining Control Area as per the requirements of Policy 3.

4.2. The Attaining Control Area assumes responsibility for CONTROL AREA services required by the assigned loads and/or resources. The Attaining Control Area assumes all regulation, contingency reserves and other CONTROL AREA responsibilities for the loads and/or resources in question.

4.3. Energy exchanged between the Native and Attaining Control Areas by the PSEUDO TIE method is accounted for by the associated revenue meter reading for the operating hour (if such meter exists at the dynamically assigned resource or load) or energy calculated by integrating associated telemetered real time signal over the operating hour. Agreements must be in place, with the applicable transmission providers, to address the physical or financial provision of transmission losses.

5. Trouble Response

5.1. The Native Control Area, Attaining Control Area, and INTERMEDIARY CONTROL AREAS shall agree before implementation of the PSEUDO-TIE on a plan for how the CONTROL AREAS will operate during a loss of the PSEUDO-TIE telemetry signal such that all involved CONTROL AREAS are using the same value. The CONTROL AREAS may agree to hold the last known good value, use an average load profile value, or have one party provide the other with a manual override value at some acceptable frequency of update.

5.2. The Native Control Area, Attaining Control Area and INTERMEDIARY CONTROL AREAS should agree before implementation of the PSEUDO-TIE upon a plan for how the load will be served during abnormal system conditions including periods of time when the interconnection between them is lost. The Native Control Area, Attaining Control Area and INTERMEDIARY CONTROL AREAS shall also agree before implementation of the PSEUDO-TIE how the entities will respond during abnormal system conditions, including periods of time when the connection between them is lost.

6. Compliance with NERC Operating Policy

6.1. The implementation of a PSEUDO-TIE may confer upon the Attaining Control Area additional responsibilities for compliance with NERC Operating Policy for the load or generation that has been transferred.

See Appendix D “ACE Equation Modification for Pseudo-Ties”
C. System Modeling

The assignment of load or generation into the control response of another CONTROL AREA must be appropriately captured in the IDC and security analysis system models of other TRANSMISSION PROVIDERS, CONTROL AREAS, and RELIABILITY COORDINATORS. It is the obligation of each CONTROL AREA to assure that the dynamic transfer of load or generation is coordinated with the RELIABILITY COORDINATOR(S) that have responsibility over the Native, Attaining and CONTRACT INTERMEDIARY CONTROL AREAS so that the method of dynamic transfer can be considered in the system modeling of the generation or load affected, and necessary data provision requirements are met. [See also, Appendix 4B – Electric System Security Data]

- It is the responsibility of the Attaining Control Area dynamically transferring load into its effective boundaries through PSEUDO-TIES to ensure that load forecasts and subsequent CONTROL AREA reporting reflect the load incorporated within its CONTROL AREA boundaries.

- If the reliability impact of the PSEUDO-TIE cannot be accurately captured in the IDC and the security analysis system models of other TRANSMISSION PROVIDERS, CONTROL AREAS, and RELIABILITY COORDINATORS, the parties must implement the dynamic transfer either through use of a DYNAMIC SCHEDULE, or through a combined implementation of a PSEUDO-TIE and DYNAMIC SCHEDULE where the load or generation within the Native Control Area is separately modeled in the IDC.
## Assignment of Control Area Obligations

<table>
<thead>
<tr>
<th>Control Area’s Obligation/modeling</th>
<th>Pseudo tie</th>
<th>Dynamic schedule</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gen planning and reporting and outage coordination</td>
<td>Attaining CA</td>
<td>Typically Native Control Area but may be re-assigned (wholly or a portion) to the Attaining CA</td>
</tr>
<tr>
<td>CPS and DCS recovery /reporting and RMS</td>
<td>Attaining CA</td>
<td>Attaining and/or Native CA (depending on agreements)</td>
</tr>
<tr>
<td>Control Area jurisdiction</td>
<td>Attaining CA</td>
<td>Native CA</td>
</tr>
<tr>
<td>Control Area services</td>
<td>Attaining CA</td>
<td>Native CA</td>
</tr>
<tr>
<td>FERC Schedules 3-6 and other ancillary services as required</td>
<td>Attaining CA</td>
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</tr>
<tr>
<td>Ancillary services associated with transmission</td>
<td>Attaining/Native CA (as agreed)</td>
<td>Attaining/Native CA (as agreed)</td>
</tr>
<tr>
<td>FERC Schedules 1-2 and other ancillary services as required</td>
<td>Attaining/Native CA (as agreed)</td>
<td>Attaining/Native CA (as agreed)</td>
</tr>
<tr>
<td>ACE frequency bias calc/setting</td>
<td>The Native and Attaining Control Areas shall adjust the control logic that determines their FREQUENCY BIAS SETTING to account for the FREQUENCY BIAS characteristics of the loads and/or resources being assigned between CONTROL AREAS by the PSEUDO-TIE</td>
<td>The Attaining Control Area should include the load from its DYNAMIC SCHEDULE as a part of its forecast load to set frequency bias requirement. The Native Control Area should change its load used to set frequency bias setting by the same amount in the opposite direction</td>
</tr>
<tr>
<td>Load forecasting and reporting</td>
<td>Attaining CA</td>
<td>Native CA</td>
</tr>
</tbody>
</table>
Appendix A – Proposed Definitions

ATTAINING CONTROL AREA. A CONTROL AREA bringing generation or load into its effective control boundaries through dynamic transfer from the Native Control Area.

DYNAMIC SCHEDULE. A telemetered reading, or value that is updated in real-time and used as a schedule in the AGC/ACE equation of the affected Control Areas and the integration of which is treated as a schedule for interchange accounting purposes.

DYNAMIC TRANSFER. The provision of the real-time monitoring, telemetering, computer software, hardware, communications, engineering, energy accounting (including inadvertent interchange), and administration required to implement a DYNAMIC SCHEDULE or PSEUDO-TIE.

DYNAMIC TRANSFER SIGNAL. The electronic signal used to implement a PSEUDO-TIE or DYNAMIC SCHEDULE.

FREQUENCY RESPONSE. The provision of capacity from IOS RESOURCES that deploys automatically to stabilize frequency following a significant and sustained frequency deviation on the INTERCONNECTION. (IOS Reference Document)

Integration in the terms for Dynamic Schedule and Pseudo-Tie above, means the value could be mathematically calculated or determined mechanically with a metering device.

INTERCONNECTED OPERATIONS SERVICE (IOS). A service (exclusive of basic energy and transmission services) that is required to support the reliable operation of interconnected BULK ELECTRIC SYSTEMS. (IOS Reference Document)

NATIVE CONTROL AREA. A CONTROL AREA from which a portion of its physically interconnected generation and/or load is assigned from its effective control boundaries through dynamic transfer to the Attaining Control Area

PSEUDO-TIE. A telemetered reading, or value that is updated in real-time, representative of generation or load assigned dynamically between control areas and used as a tie line flow in the affected control areas’ AGC/ACE equation, but for which no physical Control Area tie actually exists. To the extent that no associated energy metering equipment exists, the INTEGRATION of the telemetered real time signal is used as a metered MWh value for interchange accounting purposes.

REGULATION. The provision of generation and load response capability, including capacity, energy, and maneuverability, that responds to automatic controls issued by the Balancing Authority. (IOS Reference Document)
Appendix B – Dynamic Transfer Requirements

To implement a dynamic transfer the following entities must:

Requirements – Operating Authorities

1. Dynamic Transfer Signal

**PSEUDO-TIE** – The Native, Attaining and CONTRACT INTERMEDIARY CONTROL AREAS shall each receive the dynamic transfer signals and incorporate it into their AGC systems on the NET ACTUAL INTERCHANGE side of their ACE equation, in the same way as is done with METERED INTERCHANGE.

**DYNAMIC SCHEDULE** – The SOURCE, SINK and CONTRACT INTERMEDIARY CONTROL AREAS shall each receive the dynamic transfer signal and incorporate it into their AGC systems on the NET SCHEDULED INTERCHANGE side of their ACE equation, in the same way as is done with schedules.

2. Performance Requirements

Use of a PSEUDO-TIE or DYNAMIC SCHEDULE does not exempt a CONTROL AREA from complying with the control performance and interchange scheduling requirements of Policies 1 and 3.

3. Coordination of ACE

**PSEUDO-TIE** – The Native and Attaining Control Areas shall adjust the control logic that determines their FREQUENCY BIAS SETTING to account for the FREQUENCY BIAS characteristics of the loads and/or resources being assigned between CONTROL AREAS by the PSEUDO-TIE.  [Policy 1.C., “Frequency Response and Bias”].

**DYNAMIC SCHEDULE** – The Attaining Control Area should include the load from its DYNAMIC SCHEDULE as a part of its forecast load to set frequency bias requirement.  The Native Control Area should change its load used to set frequency bias setting by the same amount in the opposite direction.

4. Frequency Bias Setting Adjustment.

**PSEUDO-TIE** – The Native and Attaining Control Areas shall adjust the control logic that determines their FREQUENCY BIAS SETTING to account for the FREQUENCY BIAS characteristics of the loads and/or resources being assigned between CONTROL AREAS by the PSEUDO-TIE.  [Policy 1.C., “Frequency Response and Bias”].

**DYNAMIC SCHEDULE** – The Attaining Control Area should include the load from its DYNAMIC SCHEDULE as a part of its forecast load to set frequency bias requirement.  The Native Control Area should change its load used to set frequency bias setting by the same amount in the opposite direction.

5. Scheduling of Transmission

Transmission service must be procured per the tariff requirements of the applicable TRANSMISSION PROVIDER(S).
All transmission necessary to deliver the energy must be reserved and scheduled with the Native, Attaining and CONTRACT INTERMEDIARY CONTROL AREAS according to the applicable requirements specified in Policy 3.

6. Coordination of Power Transfers
The Native, Attaining and CONTRACT INTERMEDIARY CONTROL AREAS shall agree upon the allowable characteristics of the power transfers and the method for calculation of the maximum magnitude of the dynamic transfer signal(s) as appropriate.

DYNAMIC SCHEDULES are to be implemented in the ACE equation as scheduled interchange in the direction from the Generation Control Area to the Load Control Area. If the power flows associated with the dynamic schedule were expected to be bi-directional, two separate dynamic schedules would be required (each schedule to be implemented as unidirectional following the “gen-to-load” direction convention).

The CONTROL AREA shall ensure that the applicable limits applied to the particular method of the dynamic transfer meet the requirements of the TRANSMISSION PROVIDER.

7. Metering and Communications
The Native, Attaining and CONTRACT INTERMEDIARY CONTROL AREAS shall agree upon the metering and telecommunications requirements for the PSEUDO-TIES or DYNAMIC SCHEDULE(S). CONTROL AREAS shall comply with these requirements in the implementation of the dynamic transfer(s).

8. Calculation of Actual Energy Transfer
The Native, Attaining and CONTRACT INTERMEDIARY CONTROL AREAS shall agree on the method to be used for calculating the total amount of energy transferred (including losses) through the dynamic transfer on an hourly basis. CONTROL AREAS will check and agree on such hourly, calculated energy transfers and use these checked and agreed quantities in all of their energy accounting.

9. Loss of Dynamic Transfer Signal
Prior to implementation of the dynamic transfer, the involved CONTROL AREAS shall agree on actions and/or procedures to be implemented in an event of loss of the dynamic signal. Such agreed upon actions and/or procedures must be implemented any time the Native, Attaining or CONTRACT INTERMEDIARY CONTROL AREA loses the dynamic transfer signal.

10. Base Case Load Study Case
The use of transmission service for a dynamic transfer shall be modeled in the base case power flow study cases. Such modeling must be done for the dynamic transfer at each end of its range, and for as many other points within its range as required to ensure that the dynamic transfer will not cause reliability problems in real time.

Requirements – Operating Authorities and Load-Serving Entities

11. Telemetry
The entity requesting a PSEUDO-TIE or DYNAMIC SCHEDULE is responsible for ensuring that signal processing and communications equipment required in order to implement that specific
type of dynamic transfer has been made available to each of the parties to the dynamic transfer. All dynamic transfer signals must be received and utilized by the Native, Attaining and CONTRACT INTERMEDIARY CONTROL AREAS. All equipment installed as part of the dynamic transfer should have appropriate associated alarms implemented such that the party using that equipment immediately knows any equipment failure.

12. Supporting Ancillary Services

The entity requesting a dynamic transfer shall schedule, in accordance with tariffs of the applicable transmission provider(s), Ancillary Services necessary to implement the dynamic transfer.

13. Transmission Reservation

Sufficient transmission service, with the tag indicating the appropriate priority, must be reserved throughout the contract path. (Note: Sufficient, in this context, means, “transmission whose availability is commensurate with the energy supplier’s commercial obligations to deliver energy to their customer.”)

14. Transmission Scheduling

Transmission service to enable the dynamic transfer must be reserved consistent with the tariff requirements of the applicable TRANSMISSION PROVIDER(S) throughout the contract path.

15. Transaction Tagging

The entity requesting a dynamic transfer through a DYNAMIC SCHEDULE shall be responsible for submitting an Interchange Transaction Tag for the schedule. [Policy 3.A., “Interchange Transactions’’]
Appendix C – ACE Equation Modifications – Dynamic Schedules

ACE Equation Modifications

Typically:

\[ ACE = (N_{IA} - N_{IS}) - 10F_b (F_A - F_S) - I_{ME} \]

where:

- \( N_{IA} \) = Net Actual Interchange
- \( N_{IS} \) = Net Scheduled Interchange
- \( F_b \) = Control Area Frequency Bias
- \( F_A \) = Actual Frequency
- \( F_S \) = Scheduled Frequency
- \( I_{ME} \) = Meter Error Correction

For a DYNAMIC SCHEDULE the \( N_{IA} \) remains unchanged, but the \( N_{IS} \) term becomes:

\[ N_{IS} = N_{IS} - N_{ISDSGE} + N_{ISDSGI} + N_{ISDSLE} - N_{ISDSLI} \]

where:

- \( N_{IS} \) = Net sum of non-dynamically scheduled transactions
- \( N_{ISDSGE} \) = sum of dynamically scheduled generation external to the CONTROL AREA (ATTAINING CONTROL AREA).
- \( N_{ISDSGI} \) = sum of dynamically scheduled generation internal to the CONTROL AREA (NATIVE CONTROL AREA).
- \( N_{ISDSLE} \) = sum of dynamically scheduled load external to the CONTROL AREA (ATTAINING CONTROL AREA).
- \( N_{ISDSLI} \) = sum of dynamically scheduled load internal to the CONTROL AREA (NATIVE CONTROL AREA).

Consider the example where a 100 MW generator is allocated from a native control area to an attaining control area using a Dynamic Schedule:
Attaining Control Area

NIS (no Dynamic Schedule) = 400MW
NIS (with Dynamic Schedule) = 300MW

Native Control Area

NIS (no Dynamic Transfer) = 700MW
NIS (with Dynamic Transfer) = 800MW

[See also, Appendix 1A Subsection B – “The Area Control Error (ACE) Equation” for examples on sign conventions used in the equations.]
Appendix D – ACE Equation Modifications – Pseudo-Ties

ACE Equation Modifications

Typically:

\[ ACE = (NIA - NIS) - 10F_b (F_A - F_S) - I_{ME} \]

where:

- \( NIA \) = Net Actual Interchange
- \( NIS \) = Net Scheduled Interchange
- \( Fb \) = Control Area Frequency Bias
- \( FA \) = Actual Frequency
- \( FS \) = Scheduled Frequency
- \( IME \) = Meter Error Correction

For PSEUDO-TIE/AGC INTERCHANGE the \( NIS \) remains unchanged, but the \( NIA \) term becomes:

\[ NIA = NI_a - NI_{APTGE} + NI_{APTGI} + NI_{APTL} - NI_{APTLI} \]

where:

- \( NI_a \) = Net sum of tie line flows
- \( NI_{APTGE} \) = sum of AGC INTERCHANGE generation external to the CONTROL AREA (ATTAINING CONTROL AREA).
- \( NI_{APTGI} \) = sum of AGC INTERCHANGE generation internal to the CONTROL AREA (NATIVE CONTROL AREA).
- \( NI_{APTL} \) = sum of AGC INTERCHANGE load external to the CONTROL AREA (ATTAINING CONTROL AREA).
- \( NI_{APTLI} \) = sum of AGC INTERCHANGE load internal to the CONTROL AREA (NATIVE CONTROL AREA).

Consider the example where a 100MW generator is allocated from a Native Control Area to an Attaining Control Area using a Pseudo-Tie:

Attaining Control Area

- \( NIA \) (no Pseudo-Tie) = 300MW
- \( NIA \) (with Pseudo-Tie) = 400MW
Native Control Area

NIA (no Pseudo-Tie) = 800MW

NIA (with Pseudo-Tie) = 700MW

[See also, Appendix 1A Subsection B – “The Area Control Error (ACE) Equation” for examples on sign conventions used in the equations.]
Appendix E – ACE Equation – Supplemental Regulation Service as a Dynamic Schedule

Supplemental Regulation Service is when one Control Area provides all or part of the regulation requirements of another Control Area. The Control Areas implement a Dynamic Schedule incorporating the calculated portion of the ACE signal that has been agreed upon between them. This is accomplished by adding another component to the scheduled interchange component of the ACE equation for both Control Areas. Care should be taken to maintain the proper sign convention to ensure proper control, with the Control Area purchasing regulation service subtracting the Supplemental Regulation Service from their ACE while the Control Area providing the service adds it to theirs.

If the Supplemental Regulation Service includes a calculated assistance between the Native Control Area and the Attaining Control Area for recovery from the loss of generation, then both Control Areas are responsible for assuring that DCS compliance reporting requirements are met in accordance with NERC Policy 1.

Note that all requirements for dynamic scheduling must be observed while providing Supplemental Regulation Service. ACE equation modifications required for Supplemental Regulation Service:

**ACE Equation Modifications**

Typically:

\[ ACE = (NIA - NIS) - 10Fb(F_A - F_S) - IME \]

where:

- \( NIA \) = Net Actual Interchange
- \( NIS \) = Net Scheduled Interchange
- \( Fb \) = Control Area Frequency Bias
- \( FA \) = Actual Frequency
- \( FS \) = Scheduled Frequency
- \( IME \) = Meter Error Correction

For a Dynamic Schedule the \( NIA \) remains unchanged, but the \( NIS \) term becomes:

\[ NIS = NI_s - NI_{SDS\text{GE}} + NI_{SDSGI} + NI_{SDGLE} - NI_{SDSLI} \]

where:

- \( NI_s \) = Net sum of non-dynamically scheduled transactions
- \( NI_{SDS\text{GE}} \) = sum of dynamically scheduled generation external to the control area (Attaining Control Area).
NISDSGI = sum of dynamically scheduled generation internal to the control area (NATIVE CONTROL AREA).

NISDSLI = sum of dynamically scheduled load internal to the CONTROL AREA (NATIVE CONTROL AREA).

For a DYNAMIC SCHEDULE used to implement SUPPLEMENTAL REGULATION SERVICE the NI_A remains unchanged, but the NI_S term becomes:

\[ NI_S = NI_s - NISDSGE + NISDSGI + NI_SDGLE - NISDSLI - NISRSE + NISRSI \]

where:

NI_s = Net sum of non-dynamically scheduled transactions

NISDSGE = sum of dynamically scheduled generation external to the CONTROL AREA (ATTAINING CONTROL AREA).

NISDSGI = sum of dynamically scheduled generation internal to the CONTROL AREA (NATIVE CONTROL AREA).

NISDSLE = sum of dynamically scheduled load external to the CONTROL AREA (ATTAINING CONTROL AREA).

NISRSE = sum of dynamically scheduled SUPPLEMENTAL REGULATION SERVICE external to the CONTROL AREA (CONTROL AREA purchasing the SUPPLEMENTAL REGULATION SERVICE).

NISRSI = sum of dynamically scheduled SUPPLEMENTAL REGULATION SERVICE internal to the control area (CONTROL AREA selling the SUPPLEMENTAL REGULATION SERVICE)
Introduction

Geomagnetic Disturbances (GMDs) are capable of causing serious disruptions to electric power systems, especially in the northern United States and Canada. This Reference Document explains how GMD watches, alerts, and warnings are provided to the Reliability Coordinators and other operating entities in the Eastern, ERCOT, TransEnergie, and Western Interconnections.

The National Oceanic and Atmospheric Administrations Space Environmental Center (SEC – http://www.sec.noaa.gov/today.html), located in Boulder, Colorado, provides a solar disturbance forecasting service. Although SEC is unable to predict precisely when solar flares will occur, it is able to determine when the disturbance is just beginning.

The information from SEC is made available to the Midwest ISO (MISO), St. Paul, Minnesota office, which has been designated to receive and disseminate notifications of possible GMDs to Reliability Coordinators and Control Areas in the Eastern and ERCOT Interconnections. The information from SEC is also made available to Bonneville Power Administration (BPA), which has been designated to receive notifications of possible GMDs and to disseminate such notifications to Reliability Coordinators and other operating entities within the Western Interconnection. The TransEnergie Interconnection receives notifications of possible GMDs from the Solar Terrestrial Dispatch Center.

Terms

The complete Glossary of Solar Terrestrial Terms is located at http://www.sec.noaa.gov/info/glossary.html.

A-Index – A daily index of geomagnetic activity derived as the average of the eight 3-hourly A-indices.

A-Index Watch – An A-Index Watch is issued when the daily Boulder, Colorado A-index is predicted to be greater than 20, 30, 50, or 100, with one day or greater lead-time, in the daily forecasts issued by SEC. A-index watches are issued for valid times corresponding to entire calendar days, based upon the daily analyses and forecasts produced by SEC. They serve as a long lead-time prediction of the expected trend in geomagnetic activity, within the limits of what the 24-hour A-index value can describe.

Ap-Index – An averaged planetary A-Index based on data from a set of specific stations.

Flare – A sudden eruption of energy on the solar disk lasting minutes to hours, from which radiation and particles are emitted.

Geomagnetic Storm – A worldwide disturbance of the earth’s magnetic field, distinct from regular diurnal variations.

K-Index – A 3-hourly quasi-logarithmic local index of geomagnetic activity relative to an assumed quiet-day curve for the recording site. Range is from 0 to 9. The K-index measures the deviation of the most disturbed horizontal component.

K-Index Warning – K-Index Warnings are issued and/or extended for any period with expected values of K equal to or greater than 4. Higher K-Index Warnings supersede lower ones. A more thorough
description of K-Index Warnings is provided at http://www.sec.noaa.gov/alerts/description.html#K. K-Index Warnings are issued by SEC under two conditions:

1. Warning of expected onset of geomagnetic activity, and/or,
2. Warning of expected persistence of geomagnetic activity.

K-Index Alert – K-Index Alerts, for values of K-4 through K-9, are issued on a near real-time criteria, based on thresholds of deflection from quiet-day curve values for geomagnetic field components over synoptic, 3-hour periods. A more thorough description of K-Index Alerts is provided at http://www.sec.noaa.gov/alerts/description.html#K.

**Explanation of Geomagnetic Disturbance Watches, Warnings and Alerts**

The following table defines geomagnetic activity in terms of the A and K Indexes. “A” refers to the 24-hour A-Index observed at a mid-latitude observatory such as Fredericksburg, Virginia, not the planetary A-Index (Ap) that is based on data from a set of specific stations. The K-Indices are, likewise, mid-latitude values.

NOTE: Sudden commencements are indicated by beginning times, given to the nearest minute. Gradual commencements are indicated by beginning times, to the nearest hour.

<table>
<thead>
<tr>
<th>Activity</th>
<th>A and K Indexes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Quiet</td>
<td>A &lt; 7, usually no K-indices &gt; 2</td>
</tr>
<tr>
<td>Unsettled</td>
<td>7 &lt; A &lt; 15, usually no K-indices &gt; 3</td>
</tr>
<tr>
<td>Active</td>
<td>15 &lt; A &lt; 30, a few K-indices of 4</td>
</tr>
<tr>
<td>Minor geomagnetic storm</td>
<td>30 &lt; A &lt; 50, K-indices mostly 4 and 5</td>
</tr>
<tr>
<td>Major geomagnetic storm</td>
<td>50 &lt; A &lt; 100, K-indices mostly 5 and 6</td>
</tr>
<tr>
<td>Severe geomagnetic storm</td>
<td>A &gt; 100, some K-indices 7 or greater</td>
</tr>
</tbody>
</table>

**Minimum Reporting Requirements**

Each Interconnection shall designate an operating entity (e.g. a Reliability Coordinator) to receive geomagnetic disturbance watches, alerts and warnings. All K-7 or higher GMD warnings and alerts shall be routed by established procedures to operating entities within the applicable Interconnection.

**The Geomagnetic Disturbance Phenomenon**

Solar flares cause relatively rapid transient fluctuation in the earth’s magnetic field (geomagnetic field). These transient geomagnetic field variations produce an induced earth-surface-potential (ESP). The ESP can be on the order of five to ten volts per mile, and results in geomagnetically induced currents (GIC). These currents cause abnormal disturbances in communication, pipeline, railroad signal, and power systems that are grounded to the earth at points remote from each other. The periodicity of the GIC varies over a very wide cycle range. Micro-pulsations are superimposed on alternations spanning a very wide band of low frequencies. Some GIC have a fundamental period on the order of minutes, appearing as quasi-dc compared to 60 Hz or higher frequency.
Geomagnetic storms can produce spurious, quasi-dc currents in electric power systems. Power system disturbances due to the geomagnetic storms were noted as early as 1940. Other major power system disturbances due to geomagnetic storms occurred in 1957, 1958, 1968, 1970, 1972, 1974, 1979, 1982, 1983, and 1989.

Studies have reaffirmed that geological conditions override the effect of latitude. The magnitude of the induced earth-surface-potential (ESP) per mile is normally greater with increasing latitude, however, in areas, which are located over a highly resistive igneous rock formation, the ESP forces large quasi-dc current flows over the transmission system rather than through the higher resistivity surface rock.

Geomagnetic storms cause large fluctuations in the earth’s magnetic field and differences in potential between points of ground. It is known that during these storms, geomagnetically induced currents (GIC) are produced in the electric power systems. These GICs enter and exit through grounded neutrals of wye-connected transformers. The GICs can be many times larger than the Root Mean Square (RMS) value of the AC exciting current, resulting in severe half-cycle saturation and increased transformer VAR demands. Problems, which have been detected during solar magnetic disturbances, are:

- Unusual noises and heating in transformers
- Real and reactive power swings
- Elevated neutral amperes in transformers
- Frequency excursions
- Tripping of capacitor banks by neutral ground current
- Harmonic currents
- Hunting of automatic LTC transformers
- Voltage fluctuations
- Communication system problems
- Oscillograph operations
- Operation or non-operation of protective relays
- Negative sequence relays alarmed
This document provides the NERC Control Performance Compliance Survey coordinator with specific instructions on calculating the control performance of the control area and instructions to complete the survey forms contained in the document as CPS Form 1 and 2 and Form DCS.

The control area is required to continuously monitor its control performance and report its compliance results at the end of each month. This training document provides an explanation of the reporting requirements for the NERC Control Performance Standard.

A. Area Control Error

The control area’s Area Control Error (ACE) is the basis for the calculation of control parameters used to evaluate control performance. One part of the NERC Control Performance Standard (CPS) is defined by the control parameter:

$$\frac{ACE_i}{-10B_i} * F_i$$

wherein the subscript 1 indicates one-minute clock averages. This parameter is used to determine a control area’s control performance with respect to the control area’s impact on system frequency. The values of ACE to be used throughout the calculation of the control parameter shall 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 contains 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, WSCC’s automatic time error correction, etc.).

B. Performance Standard

The CPS is composed of two measures. One measure is a statistical measure of ACE variability and its relationship to frequency error. The second measure is a statistical measure designed to limit unacceptably large net unscheduled power flows. These two measures define the NERC Control Performance Standard. The NERC Control Performance Standard is the measure against which all control areas will be evaluated.

The first measure of the CPS survey provides a measure of the control area’s performance. This control performance measure is defined in Section B.1.1.1. The measure is intended to provide the control area
with a frequency-sensitive evaluation of how well the respective area met its demand requirements. The measure is not designed to be a visual indicator that an operator would use to control system generation. Nor is this measure designed to address the issue of unscheduled power flows, or minimization of inadvertent interchange.

The second measure of the CPS survey is designed to bound ACE ten-minute averages and provides an oversight function to limit excessive unscheduled power flows that could result from large ACEs. The measure to limit the magnitude of ACE is described in Section B.1.1.2.

These measurements of control performance apply to all conditions (i.e., both normal and disturbance conditions). The CPS is supplemented by a Disturbance Control Standard that establishes bounds for system recovery. The following discussion expands the definitions of the criteria found in Operating Policy I.E. — Control Performance and defines the respective measurements and associated criteria.

1. Continuous Monitoring Requirements. The NERC Control Performance Standard defines a minimum acceptable control performance that a control area is expected to maintain over all operating conditions.

1.1. Parameters. The Control Performance Standard imposes two requirements.

1.1.1. CPS1. Over a given period, the average of the clock-minute averages of a control area’s [ACE divided by ten times its bias] times the corresponding clock-minute averages of the Interconnection’s frequency error shall be less than the constant on the right-hand side of the following inequality:

\[
AVG_{Period}\left(\frac{ACE_i}{-10B_i}\right) \times \Delta F \leq \varepsilon_1^2 \\
\text{or} \\
\frac{AVG_{Period}\left(\frac{ACE_i}{-10B_i}\right) \times \Delta F}{\varepsilon_1^2} \leq 1
\]

where:

- \(ACE_i\) is the clock-minute average of ACE (as ACE is defined in Section A),
- \(B_i\) is the frequency bias of the control area. For those areas with variable bias, an area should accumulate \(ACE/(–10B)\) through the AGC cycles of a minute, and save the averaged value at the end of the minute as the clock-minute value of \(ACE/(–10B)\),
- \(\varepsilon_1\) 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 a given year. The bound is the same for every control area within an Interconnection,
- \(\Delta F\) 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 control area,
- Period is defined as:
  a) one year for control area evaluation
  b) one month for Resources Subcommittee review
1.1.2. CPS2. Over a clock ten-minute period, the ten-minute averages of a control area’s ACE shall be less than the constant on the right-hand side of the following inequality:

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

where:

\[ L_{10} = 1.65 \epsilon_{10} \sqrt{(-10B_i)(-10B_i)} \]

\( \epsilon_{10} \) is a constant derived from the targeted frequency bound. It is the targeted RMS of ten-minute average frequency error from schedule based on frequency performance over a given year. The bound, \( \epsilon_{10} \), is the same for every control area within an Interconnection.

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%),

\( B_i \) is the frequency bias of the control area, and

\( B_s \) is the sum of the frequency bias settings of the control areas 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:

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

\( B_{\text{minimum}} \) is the area’s minimum allowed bias.

1.2. Targeted Frequency Bounds. The Targeted Frequency Bounds, \( \epsilon_{1} \) and \( \epsilon_{10} \), are based on historic measured frequency error. These bounds embody the targeted frequency characteristics used for developing the Control Performance Standard. Each Interconnection will be assigned its own frequency bounds.

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

1.2.1. NERC Resources Subcommittee (RS) defines a desired frequency profile. This profile will be derived from the frequency experienced over a RS-selected one-year period.

1.2.2. NERC RS collects the 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 from schedule. These values are derived from data samples over a given year. NERC RS calculates the targeted
frequency bounds, $f_1$ and $L_{10}$, to recognize the desired performance of frequency for each Interconnection.

1.3. **Compliance for Control Areas.** A control area that does not comply with CPS is not providing its required regulation service.

1.3.1. If a control area does not comply with the CPS, the control area is not permitted to provide regulation or other services related to control performance for any other control area(s) or other entities. Those services shall be determined by the NERC RS.

1.3.2. A control area failing to comply shall take immediate corrective action and achieve compliance within three months. If necessary, a control area shall buy sufficient supplemental regulation to achieve compliance.

1.4. **Compliance for Control Areas Providing Regulation.** A control area is not permitted to provide regulation or other services related to control performance (as determined by the NERC Resources Subcommittee) for (an)other control area(s) or other entities external to that control area, if the former control area does not comply with the CPS.

1.5. **Compliance for Control Areas Participating in Supplemental Regulation.** A control area providing or receiving supplemental regulation, either through dynamic schedules or pseudo-ties, will continue to be evaluated on the characteristics of its own area control error with the supplemental regulation service included. The for each of the affected control areas will not change.

$$\left[\frac{ACE_i}{-10B_i}\right] \times \Delta F_i$$

1.6. **Compliance for Control Areas Participating in Overlap Regulation.**

1.6.1. **Control Areas Providing Overlap Regulation.** A control area providing overlap regulation shall continue to be evaluated on the characteristics of the combined areas’ ACE. The provider control area must calculate and use the combined limit using the sum of its own frequency bias setting, $B_i$, and the frequency bias setting, $B_j$, of the control area for which it is providing the overlap regulation.

1.6.2. **Control Areas Receiving Overlap Regulation.** A control area receiving overlap regulation service shall not have its control performance evaluated.

2. **Disturbance Conditions.** During a disturbance, controls cannot usually maintain ACE within the criteria for normal load variation. However, an area is expected to activate operating reserve to recover ACE within fifteen minutes. This requires that a disturbance condition be defined. 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. Regions may optionally reduce the 80% threshold, provided that normal operating characteristics are not being considered or misrepresented as contingencies. Normal operating characteristics are excluded because DCS only measures the recovery from sudden, unanticipated losses of supply-side resources.

Normal load and generation excursions (e.g., pumped storage hydro, arc furnace, rolling steel mill, etc.) that influence ACE are not reportable disturbance conditions.

2.1. **Control Area.** A CONTROL AREA shall return its ACE either to zero or to its pre-disturbance ACE level within fifteen minutes following a disturbance. A control area may, at its discretion, measure its compliance based on the ACE measured fifteen
minutes after the disturbance, or based on the maximum ACE recovery measured within the fifteen minutes following the disturbance.

2.2. **Reserve Sharing Group.** The disturbance control compliance for a control area within a Reserve Sharing Group is based on the compliance of the Reserve Sharing Group (according to the compliance method chosen in section 3.2.2. of Policy 1A). A reserve sharing group area may, at its discretion, measure this recovery based on the combined ACE measured fifteen minutes after the disturbance, or on the maximum combined ACE recovery measured within the fifteen minutes following the disturbance.
C. Calculation of Compliance

1. **Control Compliance Rating.** Control area compliance will be determined by examining both CPS parameters. One parameter (CPS1) measures control impact on frequency. This parameter is calculated from a MW-Hz error value computed over a sliding 12-month period. The second parameter (CPS2) is a function of the ten-minute ACE magnitudes over a one-month period. Compliance to the two measures is outlined below:

   Control Compliance Rating = Pass if CPS1 \( \geq 100\% \) and CPS2 \( \geq 90\% \)
   Control Compliance Rating = Fail if CPS1 \( < 100\% \) or CPS2 \( < 90\% \)

1.1. **Control Performance Standard 1 (CPS1).** The frequency-related parameter, CPS1, converts a compliance ratio to a compliance percentage as follows:

   \[
   CPS1 = (2 - CF) \times 100\%
   \]

   The frequency-related Compliance Factor, CF, is a ratio of all one-minute compliance parameters accumulated over 12 months divided by the Target Frequency Bound:

   \[
   CF = \frac{CF_{12\text{-month}}}{(\epsilon_1)^2}
   \]

   where: \( CF_{12\text{-month}} \) is defined in Section C.1.1.1,
   \( \epsilon_1 \) is defined in Section B.1.1.1.

   Note that compliance percentages can be calculated for other bases (month, day, shift hours, etc.) by simply replacing \( CF_{12\text{-month}} \) in the above formula with the appropriate CF value.

1.1.1. **CF_{12\text{-month} Calculation.** The rating index is derived from 12 months of data.

The basic unit of data comes from one-minute averages of ACE, frequency error and frequency bias settings.

1.1.1.1. **Clock-minute average.** A clock-minute average is the average of the reporting control area’s valid measured variable (i.e., for ACE and for frequency error, as well as for the control area’s frequency bias, as defined in section B.1.1.1.) for each sampling cycle during a given clock-minute.

   \[
   \left( \frac{ACE}{-10B} \right)_{\text{clock-minute}} = \left( \frac{\sum ACE_{\text{sampling cycles in clock-minute}}}{n_{\text{sampling cycles in clock-minute}}} \right) - 10B
   \]

   \[
   \Delta F_{\text{clock-minute}} = \frac{\sum \Delta F_{\text{sampling cycles in clock-minute}}}{n_{\text{sampling cycles in clock-minute}}}
   \]

   The control area’s clock-minute Compliance Factor (CF) becomes:
C. Calculation of Compliance

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

1.1.1.2. Hourly Average. Normally, sixty (60) clock-minute averages of the reporting area’s ACE and of the respective Interconnection’s frequency error will be used to compute the respective Hourly Average Compliance parameter.

\[ CF_{\text{clock-hour}} = \frac{\sum CF_{\text{clock-minute}}}{n_{\text{clock-minute samples in hour}}} \]

1.1.1.3. Accumulated Averages. The reporting entity can recalculate and store each of the respective clock-hour averages \( CF_{\text{clock-hour average-month}} \) as well as the respective number of samples for each of the twenty-four (24) hours (one for each clock-hour, i.e., HE 0100, HE 0200, ..., HE 2400).

\[ CF_{\text{clock-hour average-month}} = \frac{\sum_{\text{days-in-month}} [(CF_{\text{clock-hour}})(n_{\text{one-minute samples in clock-hour}})]}{\sum_{\text{days-in month}} [n_{\text{one-minute samples in clock-hour}}]} \]

\[ CF_{\text{month}} = \frac{\sum_{\text{hours-in-day}} [(CF_{\text{clock-hour average-month}})(n_{\text{one-minute samples in clock-hour averages}})]}{\sum_{\text{hours-in day}} [n_{\text{one-minute samples in clock-hour averages}}]} \]

The 12-month Compliance Factor becomes:

\[ CF_{12\text{-month}} = \frac{\sum_{i=1}^{12} (CF_{\text{month}-i})(n_{\text{one-minute samples in month}-i})}{\sum_{i=1}^{12} [n_{\text{one-minute samples in month}-i}]} \]

Note that if data was not collected for all days of the month (or hours in day, or minutes in hour, etc.), then the summations in the above formulas should be for “sample” days (or hours, minutes, etc.).

1.1.2. Sustained Interruption in the Recording of ACE and Frequency Deviation.

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 samples during that one-minute interval be present. Should a sustained interruption in the recording of ACE or Frequency Deviation due to loss of telemetering or computer unavailability result in a one-minute interval not containing at least 50% of samples of both ACE and Frequency Deviation, that one-minute interval shall be excluded from the calculation of CPS1.

At the end of the month, each of the respective hourly averages are used to calculate that month’s Compliance Factor as follows:

### 1.2. Control Performance Standard 2 (CPS2)

The second parameter in the Control Performance Rating relates to a bound on the ten-minute average of ACE. A compliance percentage is calculated as follows:

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

The Violations\textsubscript{month} are a count of the number of periods that \( ACE_{\text{clock-ten-minutes}} \) exceeded \( L_{10} \). \( ACE_{\text{clock-ten-minutes}} \) is the sum of valid ACE samples within a clock-ten-minute period divided by the number of valid samples.

\[
\text{Violation}_{\text{clock-ten-minutes}} = 0 \text{ if } \frac{\sum ACE}{n_{\text{samples in 10-minutes}}} \leq L_{10}
\]

\[
= 1 \text{ if } \frac{\sum ACE}{n_{\text{samples in 10-minutes}}} > L_{10}
\]

Each area shall report the total number of Violations and Unavailable Periods for the month. \( L_{10} \) is defined in Section B.1.1.2.

#### 1.2.1. Determination of Total Periods\textsubscript{month} and Violations\textsubscript{month}

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

Each 24-hour period beginning at 0000 and ending at 2400 contains 144 discrete ten-minute periods (one more or less due to Daylight Saving Time). 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.

An incident of non-compliance is recorded for any ten-minute period where the absolute value of average ACE is greater than \( L_{10} \). November 21, 2002
C. Calculation of Compliance

1.2.2. Condition that Impacts the Calculation of Total Periods_{month} and Violations_{month}. A condition may arise which may impact the normal calculation of Total Periods_{month} and Violations_{month}. This condition is a sustained interruption in the recording of ACE.

1.2.2.1. Interruption in the Recording of ACE. 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. Should half or more of the ACE data be unavailable due to loss of telemetering or computer unavailability, that ten-minute interval is omitted from the calculation of CPS2.

1.3. Data Reporting. The control area is responsible for submitting the Control Performance Standard survey each month. In addition (for post-reporting analysis by the Regional Resources Subcommittee representative), the control area is responsible for retaining sufficient CF and other pertinent data (see Appendix 1H).

2. Disturbance Control Standard. A control area or reserve sharing group must calculate and report compliance with the Disturbance Control Standard for all disturbances greater than or equal to 80% of the magnitude of the control area’s or of the reserve sharing group’s most severe single contingency loss. Regional Reliability Councils may, at their discretion, require a lower reporting threshold. Disturbance Control Standard is measured as the percentage recovery, R_i

For loss of generation:

if \( ACE_A < 0 \)

then

\[
R_i = \frac{MW_{Loss} - \max(0, ACE_A - ACE_M)}{MW_{Loss}} \times 100\%
\]

if \( ACE_A \geq 0 \)

then

\[
R_i = \frac{MW_{Loss} - \max(0, - ACE_M)}{MW_{Loss}} \times 100\%
\]

where: \( MW_{LOSS} \) is the MW size of the disturbance as measured at the beginning of the loss,

\( ACE_A \) is the pre-disturbance ACE,
ACE\textsubscript{M} is the maximum algebraic value of ACE measured within the fifteen minutes following
the disturbance event. A control area or reserve sharing group may, at their discretion, set ACE\textsubscript{M} = \text{ACE}\!_{15\text{ min}}, and

ACE\textsubscript{m} is the minimum algebraic value of ACE measured within the fifteen minutes following
the disturbance event. A control area or reserve sharing group may, at their discretion, set ACE\textsubscript{m} = \text{ACE}\!_{15\text{ min}}.

2.1. Determination of MW\textsubscript{LOSS}.

Record the MW\textsubscript{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.

2.2. Determination of ACE\textsubscript{A}.

Base the value for ACE\textsubscript{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\textsubscript{A} = -25 MW.

2.3. Determination of ACE\textsubscript{M} or ACE\textsubscript{m}.

ACE\textsubscript{M} is the maximum value of ACE measured within fifteen minutes following a given
disturbance. At the discretion of the control area or of the Reserve Sharing Group,
compliance may be based on the ACE measured fifteen minutes following the
disturbance, i.e., ACE\textsubscript{M} = \text{ACE}\!_{15\text{ min}}.

ACE\textsubscript{m} is the minimum value of ACE measured within fifteen minutes following a given
disturbance. At the discretion of the control area or of the Reserve Sharing Group,
compliance may be based on the ACE measured fifteen minutes following the
disturbance, i.e., ACE\textsubscript{m} = \text{ACE}\!_{15\text{ min}}.

3. Examples.

Below is an example of the calculations required 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.
Let’s assume this area has a bias, B = -60\text{MW}/0.1 Hz.

On Day 1, at the beginning of HE 0100, the area must calculate \text{CF}_{\text{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.

<table>
<thead>
<tr>
<th>HE 0100:</th>
<th>Minute 1</th>
<th>Minute 2</th>
<th>...</th>
<th>Minute 60</th>
<th>Sum</th>
<th>\text{CF}_{\text{clock-hour}} = \Sigma(\text{CF})/n</th>
</tr>
</thead>
<tbody>
<tr>
<td>ACE!/10B</td>
<td>(Hz)</td>
<td>-20/-10(-60)</td>
<td>10/-10(-60)</td>
<td>...</td>
<td>40/-10(-60)</td>
<td></td>
</tr>
<tr>
<td>\Delta F</td>
<td>(Hz)</td>
<td>0.005</td>
<td>-0.005</td>
<td>...</td>
<td>0.005</td>
<td></td>
</tr>
<tr>
<td>\text{CF}_{\text{clock-minute}} = (ACE!/10B \times \Delta F) n</td>
<td>(Hz\textsuperscript{2})</td>
<td>-0.000167</td>
<td>-0.00083</td>
<td>...</td>
<td>-0.000333</td>
<td>0.00525</td>
</tr>
<tr>
<td>(mHz\textsuperscript{2})</td>
<td>1</td>
<td>-166.667</td>
<td>-83.333</td>
<td>...</td>
<td>333.333</td>
<td>5250.0</td>
</tr>
<tr>
<td>n (# of samples)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Note that \( n \) (# of samples) is based on the number of samples over the hour. Since CPS1 requires 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 hour-periods of the day. As the days of the month continue, the 24 hour-period \( CF_{\text{clock-hour average-month}} \) values are averaged as shown below: At the end of the month, a \( CF_{\text{month}} \) can be calculated.

<table>
<thead>
<tr>
<th>Hour</th>
<th>Day 1</th>
<th>Day 2</th>
<th>...</th>
<th>Day 31</th>
<th>Sum</th>
<th>( CF_{\text{clock-hour average-month}} = \frac{\sum(CF \times n)}{\sum(n)} )</th>
</tr>
</thead>
<tbody>
<tr>
<td>HE 0100</td>
<td>CF_{\text{clock-hour}}</td>
<td>87.5</td>
<td>93.5</td>
<td>...</td>
<td>92.0</td>
<td>1842</td>
</tr>
<tr>
<td></td>
<td>n (# of samples)</td>
<td>60</td>
<td>59</td>
<td>...</td>
<td>57</td>
<td>166,742</td>
</tr>
<tr>
<td></td>
<td>CF_{\text{clock-hour}} \times n</td>
<td>5250</td>
<td>5516.5</td>
<td>...</td>
<td>5244</td>
<td></td>
</tr>
<tr>
<td>HE 0200</td>
<td>CF_{\text{clock-hour}}</td>
<td>90.0</td>
<td>85.0</td>
<td>...</td>
<td>89.5</td>
<td>1830</td>
</tr>
<tr>
<td></td>
<td>n</td>
<td>58</td>
<td>60</td>
<td>...</td>
<td>60</td>
<td>160,170</td>
</tr>
<tr>
<td></td>
<td>CF_{\text{clock-hour}} \times n</td>
<td>5220</td>
<td>5100</td>
<td>...</td>
<td>5370</td>
<td></td>
</tr>
<tr>
<td>...</td>
<td>...</td>
<td>...</td>
<td>...</td>
<td>...</td>
<td>...</td>
<td>...</td>
</tr>
<tr>
<td>...</td>
<td>...</td>
<td>...</td>
<td>...</td>
<td>...</td>
<td>...</td>
<td>...</td>
</tr>
<tr>
<td>HE 2400</td>
<td>CF_{\text{clock-hour}}</td>
<td>89.0</td>
<td>92.0</td>
<td>...</td>
<td>89.0</td>
<td>1830</td>
</tr>
<tr>
<td></td>
<td>n</td>
<td>60</td>
<td>59</td>
<td>...</td>
<td>59</td>
<td>163,787</td>
</tr>
<tr>
<td></td>
<td>CF_{\text{clock-hour}} \times n</td>
<td>5340</td>
<td>5428</td>
<td>...</td>
<td>5251</td>
<td></td>
</tr>
</tbody>
</table>

Total \( n \) 
Total \( CF_{\text{clock-hour average-month}} \times n \) 

\( CF_{\text{month}} = \frac{\sum(CF_{\text{clock-hour average-month}} \times n)}{\sum(n)} = 88.9 \)

A rolling \( CF_{12\text{-month}} \) can be calculated using the \( CF_{\text{month}} \) values.

<table>
<thead>
<tr>
<th>Month</th>
<th>1</th>
<th>2</th>
<th>...</th>
<th>12</th>
<th>Sum</th>
<th>( CF_{12\text{-month}} = \frac{\sum(CF_{\text{month}} \times n)}{\sum(n)} )</th>
</tr>
</thead>
<tbody>
<tr>
<td>( CF_{\text{month}} )</td>
<td>88.9</td>
<td>93.3</td>
<td>...</td>
<td>91.7</td>
<td>515,030</td>
<td>91.3</td>
</tr>
<tr>
<td>( n )</td>
<td>44,208</td>
<td>42,072</td>
<td>...</td>
<td>42,875</td>
<td></td>
<td></td>
</tr>
<tr>
<td>( CF_{\text{month}} \times n )</td>
<td>3,930,888</td>
<td>3,925,345</td>
<td>...</td>
<td>3,931,655</td>
<td>47,022,239</td>
<td></td>
</tr>
</tbody>
</table>

Assuming this area has an \( \varepsilon_1 \) of 10 MHz, then its CPS1 compliance percentage would be calculated as follows (as described in section C.1.1):

\[
CF = \frac{CF_{12\text{-month}}}{(\varepsilon_1)^2}
\]

\[
= \frac{91.3}{(10)^2}
\]
C. Calculation of Compliance

\[
\frac{91.3}{100} = 0.913
\]

\[
CPS1 = (2 - CF) \times 100
\]

\[
= (2 - 0.913) \times 100 = 1.087 \times 100 = 108.7\%
\]

which is a “passing” grade (CPS1 must be greater than or equal to 100)

\begin{figure}
\centering
\includegraphics[width=\textwidth]{figure1.png}
\caption{CPS2-L\textsubscript{10} Compliance & Disturbance Control Standard, 2 Disturbance Examples}
\end{figure}

Figure 1 demonstrates various examples of L\textsubscript{10} compliance (CPS2 Standard) and a disturbance condition (Disturbance Control Standard). Note that Figure 1 is separated into six distinct, cyclic ten-minute periods. The absolute value of the algebraic mean of the ACE during each period, referred to as \(d_a\), is compared to L\textsubscript{10} (10 MW for this system) to determine a violation. 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 L\textsubscript{10} 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).
Note the pattern of the disturbance condition, which began at 0110. 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).

![Graph showing Disturbance Control Standard violation.]

**Figure 2 – L₁₀ Compliance Examples**

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 span a consecutive, uninterrupted period longer than five minutes, this period is eliminated from further CPS Standard 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 L₁₀ 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 intervals.
D. Survey Procedures

Performance Standard surveys will be conducted monthly to analyze each control area’s level of compliance with the CPS1 and CPS2 Control Performance Standards. The surveys provide a relative measure of each control area’s performance.

1. Issuance of Survey. Monthly averages are to be completed after the end of each month.

   1.1. Each control area shall return one completed copy of CPS Form 1, “NERC Control Performance Standard Survey — All Interconnections” to the Resources Subcommittee member representing the Region by the tenth working day of the month following the month reported.

2. Instructions for Control Area Survey. Using data derived from digital processing of the ACE signal, a representative from each control area will complete CPS Form 1, “NERC Control Performance Standard Survey — All Interconnections.”

   2.1. Hourly Table.

   CPS1 Report the clock-hour average compliance factor (CF) for each of the 24-hour periods and the total number of samples in each hourly average (as described in section C.1.1.1.3).

   CPS2 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.

   2.2. CPS1, CPS2 Standard Summary.

   CPS1 \( \text{CF}_{\text{month}} \) Report the monthly compliance factor and enter in this cell using the formulas and procedures described in Sections C.1.1.1.3.

   CPS1 \( \text{CF}_{12-\text{month}} \) Report the rolling 12-month compliance factor and enter in this cell using the formulas and procedures described in Sections C.1.1.1.

   CPS1 (%) Calculate the CPS1 percentage compliance and enter in this cell using the formulas and procedures described in Sections C.1.1.

   CPS2 TOTAL Sum the clock-hour average compliance factors, the number of samples, the number of violations, and unavailable ten-minute intervals recorded on the hourly tables and enter the sums on this row for each column.

   CPS2 (%) Calculate the CPS2 percentage compliance and enter in this row using the formulas and procedures described in Sections C.1.2.
3. **Instructions for Regional and NERC Surveys.** From a review of the control areas’ surveys, each Regional Survey Coordinator or RS member will complete CPS Form 2, “NERC Control Performance Standard — Regional Summary.”

3.1. Review CPS Form 1 data received from each control area in the Region for uniformity, completeness, and compliance to the instructions. Iterate with control area survey coordinators where necessary.

3.2. 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 control areas.

3.3. Forward a copy of the completed CPS Form 1 and 2 to the NERC staff.

3.4. The NERC staff will combine the Regional reports into a single summary report and send one copy to each RS member.

3.5. Each RS member is responsible for sending the summary report to the utilities in the Region.

4. **Disturbance Control Standard.**

Each Control Area or Reserve Sharing Group shall report its Disturbance Control Standard compliance quarterly. The completed Disturbance Control Standard survey shall be supplied to NERC by the 20th day following the end of the respective quarter. Where reserve sharing groups exist, the Regional Reliability Council shall decide either to report these on a control area basis or on a reserve sharing group basis. If a reserve sharing group has dynamic membership, then it will be required for the Region to convert the disturbance reporting for the group to a control area basis before reporting to NERC. If a control area basis is selected, each control area reports the reserve sharing group’s performance only for disturbances occurring in their area.

4.1. **Reportable Disturbance.** The definition of a reportable disturbance shall be provided by the respective Regional Reliability Councils. The definition shall include events that cause an ACE change greater than or equal to 80% of a control area’s or reserve sharing group’s most severe contingency. The definition of a reportable disturbance must be specified in the operating Policy adopted by each Regional Reliability Council. This definition may not be retroactively adjusted in response to observed performance.

4.1.1. **Most Severe Single Contingency.** A control area’s most severe single contingency is defined as the magnitude of the single most credible event that would cause the greatest change in the control area’s ACE or as defined by the respective Regional Council.

4.2. **Excludable Disturbances and Average Percent Recovery.** The control areas or reserve sharing group shall report both the number of reportable disturbances that occur in the given quarter, and the average percent recovery for that quarter. The control area must also report the excludable disturbances that occurred in the quarter and the average percent recovery for those excluded events.

4.2.1. **Excludable Disturbance.** An excludable disturbance is a disturbance whose magnitude was greater than the magnitude of the control area’s most severe single contingency.

4.2.2. **Average Percent Recovery.** The average percent recovery is the arithmetic average of all the calculated $R_i$’s from reportable disturbances during the given quarter. Average percent recovery is similarly calculated for excludable disturbances. (See Section C.2 for calculation of $R_i$.)

Version 2  PS–15  Approved by Operating Committee: November 21, 2002
4.3. **Contingency Reserve Adjustment Factor.** The quarterly Contingency Reserve Adjustment factor shall include only those reportable disturbances with magnitudes less than or equal to the magnitude of the respective control area’s most severe contingency.

4.3.1. **Contingency Reserve Adjustment factor.** The factor is defined as follows:

When \( n_{\text{Quarter}} \geq 0 \), then

\[
CRA_{\text{Quarter}} = 200 - \left[ \frac{\sum R_i}{n_{\text{Quarter}}} \right]
\]

When \( n_{\text{Quarter}} = 0 \), then \( CRA_{\text{Quarter}} = 100 \)

where \( n_{\text{Quarter}} \) is the number of reportable disturbances experienced during the reporting quarter.

\( i = \) reportable disturbances.

\( R_i \) is defined in section C.2.

4.3.2. **Calculation Precision.** The Adjustment Factor shall be rounded off to two decimal places.

4.3.3. **Exemptions.** Requests for exemptions for single events that cause multiple reportable disturbances (e.g. hurricanes, earthquakes, islanding, etc.) shall be submitted to the NERC Director of Compliance. Until the exemption is approved or denied, the control area or reserve sharing group shall consider the request denied.

4.4. **Contingency Reserve Adjustment Period.** Control areas shall 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 remains in effect for three months.

4.5. **Instructions for Disturbance Control Standard Survey.** Each control area or Reserve Sharing Group shall report its Disturbance Control Standard compliance quarterly on Form DCS “NERC Disturbance Control Standard Survey.”

4.5.1. Mail a copy of the completed Form DCS to the NERC staff.

4.5.2. The NERC staff will combine the Regional reports into a single summary report and send one copy to each Subcommittee member.

4.5.3. Each Subcommittee member is responsible for sending the summary report to the utilities in the Region.
## NERC Control Performance Standard Survey
### All Interconnections

**CPS**

**Form 1**

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**Year -**  
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**CPS2**  
**Month -**  0  

**Notes:**

Version 2  
Approved by Operating Committee:  
November 21, 2002
## NERC Control Performance Standard Survey – Regional Summary

### CPS Form 2

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# NERC Disturbance Control Standard Report

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Control Area/RSG:

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*1 When reporting as a Reserve Sharing Group (RSG), submit data for the entire group only and list the Control Areas comprising the RSG.

*2 APR indicates the Average Percent Recovery.

*3 Not a performance measure. For informational purposes only.

*4 (200 - a), please round to the nearest whole percentage.

### Notes/Comments:

A Control Area or Reserve Sharing Group must increase their Contingency Reserve Requirement by the Craf. CRR changes are implemented one month after the end of a reporting quarter and remain in effect for three months.
Flowgate Administration Reference Document

Version 1

Reference Document Subsections

A. General
B. Guidelines for Permanent Flowgates
C. Flowgate Administration

A. General

Purpose

The Flowgate Administration Reference Document explains how RELIABILITY COORDINATORS can add, modify, and remove flowgates from the Interchange Distribution Calculator (IDC). The procedures included in this document follow:

- Ensure that Reliability Authorities have the flowgate data that they need to manage system security.
- Ensure that market participants receive timely information about flowgate changes that they need to assess impacts on Interchange Transactions.
- Address administrative authorities, criteria, and processes for:
  - Adding and deleting “permanent” Reliability Flowgates
  - Modifying Reliability Flowgates in the Book of Flowgates
  - Defining “temporary” Reliability Flowgates
  - Expiring “temporary” Reliability Flowgates
  - Adding “temporary” Reliability Flowgates to the Book of Flowgates
  - Modifying Informational Flowgates
  - Modifying Market Redispatch Flowgates

Terms

Flowgate. A single or group of transmission elements intended to model MW flow impact relating to transmission limitations and transmission service usage. Within the IDC, Transfer Distribution Factors (see PTDFs and OTDFs as defined below) are calculated to approximate MW flow impact on the flowgate caused by point-to-point power transfers.

Flowgate Categories:

Temporary Flowgate. A flowgate created by a RELIABILITY COORDINATOR within the IDC to monitor or mitigate a Constraint for which a PERMANENT FLOWGATE has not been identified. TEMPORARY FLOWGATES expire when each new IDC base case is updated. IDC base cases are normally updated on a monthly basis.
**Permanent Flowgate.** A flowgate approved by Reliability Authority Working Group and listed in the Book of Flowgates. PERMANENT FLOWGATES remain in the IDC unless removed from the Book of Flowgates and deleted from the IDC.

**Flowgate Types:** A flowgate may be classified as one or more of the following types

**Informational Flowgate Type:** A flowgate that the RELIABILITY COORDINATOR can establish for monitoring purposes only. An INFORMATIONAL FLOWGATE does not qualify for Transmission Loading Relief (TLR) usage and should be reviewed periodically.

**Reliability PTDF Flowgate Type:** A RELIABILITY PTDF FLOWGATE is represented by the PTDF of its defined transmission element(s). The defined transmission element(s) can be the monitored element(s) or the contingent element(s). This type of flowgate qualifies for TLR usage under NERC Policy 9, “Security Coordinator Procedures.”

**Reliability OTDF Flowgate Type:** A RELIABILITY OTDF FLOWGATE is another type of Reliability Flowgate. It is represented by the OTDF on the Monitored Element(s) with the simulated outage of the critical contingency. This type of flowgate also qualifies for TLR usage under NERC Policy 9.

**Commercial Flowgate Type:** COMMERCIAL FLOWGATES contain transmission elements on which transmission service has been or is expected to be sold. Some RELIABILITY COORDINATORS and Transmission Providers use COMMERCIAL FLOWGATES in ATC calculations. A COMMERCIAL FLOWGATE status alone does not qualify for TLR usage. RELIABILITY COORDINATORS and Distribution Factor Work Group are not responsible for approving, modeling, and maintaining COMMERCIAL FLOWGATES and therefore the administrative process described in this document does not apply to COMMERCIAL FLOWGATES.

**MRD Flowgate Type:** A flowgate for which the Market Redispatch (MRD) procedure may be used to provide the equivalent relief by a TLR to mitigate a constraint. MRD Flowgates are listed on the NERC web site along with their real-time flows. An MRD FLOWGATE is necessarily a Reliability Flowgate.

**Responsibilities and Authorities**

The **Operating Reliability Subcommittee (ORS)** is responsible for:

- Reviewing all changes to the Book of Flowgates at each of its regularly scheduled meetings.
- Resolving disputes resulting from the implementation of Section B, “Guidelines for Permanent Flowgates,” or Section C, “Flowgate Administration,” in this reference document.

The **Reliability Coordinator Working Group (RCWG)** is responsible for:

- Authorizing all changes to the Book of Flowgates on a monthly basis.
- Providing semi-annual reports on flowgate changes to the ORS.

Individual **RELIABILITY COORDINATORS** are responsible for:

- Authorizing the use of TEMPORARY FLOWGATES
• Modeling TEMPORARY FLOWGATES within IDC

• Recommending conversion of TEMPORARY FLOWGATES to PERMANENT FLOWGATES

• Reviewing and updating periodically its PERMANENT FLOWGATES

• Authorizing the removal of PERMANENT FLOWGATES

The Distribution Factor Working Group (DFWG) is responsible for:

• Performing the on-going function of administering the Book of Flowgates under the direction of RCWG. Administration includes but is not limited to the following:

  1. Tracking the relationship between TEMPORARY and PERMANENT FLOWGATES for historical purposes.

  2. Reviewing flowgate data including the transmission element, which define PERMANENT FLOWGATES.

  3. Reviewing flowgate data including transmission elements that define TEMPORARY FLOWGATES used for TLR greater than TLR Level 1.

• Authorizing Book of Flowgates changes that can be unanimously agreed upon. If DFWG cannot unanimously agree, or if they see reasons for RAWG discussions, DFWG will forward the flowgate review to RAWG with its recommendations.

• Provide quarterly update to the RAWG on the Book of Flowgates changes highlighting key changes in PERMANENT FLOWGATES.

• Modeling the basic set of permanent Book of Flowgates changes as approved by RAWG.

• Maintaining and being the “owner” of the Book of Flowgates.

• Developing a posted flowgate review process for evaluating flowgates.

The NERC staff is responsible for:

• Posting the basic set of flowgates on the NERC web site, and posting IDC messages regarding flowgate changes and TEMPORARY FLOWGATE additions. IDC message posting is expected to be an automated process.
B. Guidelines for Permanent Flowgates

A Permanent Flowgate must meet at least one of the following requirements to be in the Book of Flowgates:

1. A TLR has been called for the flowgate at least once during the past two years, or
2. A TLR greater than TLR Level 1 has been called for on the Temporary Flowgate at least once during the past two years and the Temporary Flowgate was created multiple times during the past two years, or
3. The flow on the flowgate has exceeded a reasonably high percentage (i.e. 90%) of its applicable rating or Operating Security Limit (OSL) at least once during the past three years, or
4. The flow on the flowgate is expected to exceed a reasonably high percentage (i.e. 90%) of its applicable rating or the OSL in the coming year
5. DFWG or RCWG has determined that the flowgate should remain in the Book of Flowgates, or the RELIABILITY COORDINATOR recommends and presents the rationale to RCWG that a flowgate be included or retained in the Book of Flowgates.

Permanent Flowgates will not be removed from the Book of Flowgates or the IDC database unless requested by the responsible RELIABILITY COORDINATOR.
C. Flowgate Administration

The Flowgate Administration process is shown in the flowchart below.

- By Reliability Coordinator
- Need to create or modify
- By DFWG
- Temporary FG created in IDC
- Inform DFWG by DFWG FG process
- DFWG Review
- DFWG Approve?
- Yes
- RC provides additional information
- RCWG Review
- RCWG Approve?
- Yes
- ORS:
  - Reviews changes to BoF
  - Resolves disputes
- No
- Update BoF and post
- DFWG records revision
- Notify IDC provider
- Notify RC via IDC
- No
- No
Permanent Flowgates

1. ORS has final approval for the basic set of flowgates taking into account recommendations from RCWG and DFWG.

2. DFWG assists in preparing information for RCWG review and maintains records showing when flowgate decisions were made.

3. Responsible RELIABILITY COORDINATOR or its DFWG representative authorizes changes to the PERMANENT FLOWGATES through submittal to DFWG.

4. DFWG will either unanimously approve flowgates or forward flowgates to RAWG with recommendations.

5. After the flowgate approval, DFWG and IDC service provider will model the flowgate changes.

6. NERC staff will post the basic set of flowgates with a link provided via the NERC web site at crc.nerc.com.

Temporary Flowgates

1. RELIABILITY COORDINATORS along with the Transmission Providers they represent will determine the need for TEMPORARY FLOWGATES. TEMPORARY FLOWGATES can be created directly within IDC and may become available for potential TLR use within 20 minutes to one hour after they are entered into IDC. TEMPORARY FLOWGATES can be deleted at any time, and they automatically expire when each new IDC base case is updated.

2. Information regarding TEMPORARY FLOWGATE additions, modifications, or deletions is communicated to the RELIABILITY COORDINATORS via the IDC service provider. Whenever a flowgate is added, deleted, or changed, the IDC service provider will send a message to DFWG with a copy to a NERC listserver. NERC staff will publicly post the message on the NERC crc.nerc.com web page. Permanent Book of Flowgates changes will be posted separately.

3. TEMPORARY FLOWGATES will automatically expire when a new IDC base case is updated. IDC base cases are normally updated on a monthly basis. IDC model updating process schedule will be posted on the NERC web site, as it becomes known.

4. TEMPORARY FLOWGATES, which are used for TLR greater that Level 1, should go through a DFWG review. Individual RELIABILITY COORDINATORS may recommend converting a TEMPORARY FLOWGATE into a PERMANENT FLOWGATE by following Step 3 in the PERMANENT FLOWGATES section above.

Informational Flowgates

1. RELIABILITY COORDINATORS may establish an INFORMATIONAL FLOWGATE to help them monitor power flows over certain interfaces.

2. The RELIABILITY COORDINATOR establishing the INFORMATIONAL FLOWGATE will review the flowgate periodically, and remove the flowgate if no longer needed.
3. INFORMATIONAL FLOWGATES are included in the Book of Flowgates that is posted on the NERC web site.

4. INFORMATIONAL FLOWGATES may be converted to Reliability Flowgates by going through the formal recommendation process.

**MRD Flowgates**

1. The NERC Congestion Management Subcommittee (CMS) determines a list of MRD Flowgates to support the NERC MRD Procedure.

2. The DFWG or NERC staff, upon request by the CMS, notifies the IDC service provider to model changes to the MRD Flowgates for Generation Shift Factor calculation.

3. MRD Flowgates are included in the Book of Flowgates that is posted on the NERC web site.

**DFWG Flowgate Review**

RELIABILITY COORDINATORS may request the DFWG to review and revise the list of PERMANENT FLOWGATES in accordance with the guidelines detailed in Section B. A standardized approach should be used for reviewing all flowgates. The Book of Flowgates will be kept up to date so that it is consistent with the latest IDC base case. DFWG will generally not review TEMPORARY FLOWGATES unless:

- They are used for a TLR greater than Level 1.
- A flowgate is repeatedly created as a Temporary Flowgate.
- A request is made to convert a Temporary Flowgate to a Permanent Flowgate.

INFORMATIONAL FLOWGATES are not to be used for TLR. The review for INFORMATIONAL FLOWGATES may differ from that of a Reliability Flowgate. DFWG review of Reliability Flowgates for thermal purposes may differ from the review of Reliability Flowgates used for voltage or dynamic stability purposes.

Flowgate review may require the responsible RELIABILITY COORDINATOR to provide additional flowgate detail as determined by DFWG.
Reference Document

Interconnected Operations Services

Prepared by the
Interconnected Operations Services Subcommittee

Version 1.1 with Proposed Revisions
Incorporating Functional Model Definitions

March 21, 2002
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Section 1. Overview

1.1 Scope and Purpose

This Interconnected Operations Services (IOS) Reference Document was developed by the Interconnected Operations Services Subcommittee in response to a directive from the NERC Operating Committee in November 2000. Version 1.0 of the IOS Reference Document was approved by the Operating Committee in March 2001. Version 1.1 incorporates terms defined in the NERC Functional Model, as approved by the NERC Board of Trustees on June 12, 2001 and as revised on January 20, 2002.

This IOS Reference Document:

- Defines and describes the characteristics of INTERCONNECTED OPERATIONS SERVICES (IOS)
- Describes the necessity of IOS as ‘reliability building blocks’ provided by generators (and sometimes loads) for the purpose of maintaining BULK ELECTRIC SYSTEM reliability.
- Explains the relationship between OPERATING AUTHORITIES and IOS SUPPLIERS in the provision of IOS.
- Provides sample standards that could be used to define the possible obligations of OPERATING AUTHORITIES and IOS SUPPLIERS in the provision of IOS.
- Describes sample methods for performance measurement in the provision of IOS.
- Describes sample methods for the certification of IOS RESOURCES.

1.2 Definition of Terms

The definitions of IOS described in this IOS Reference Document are as follows:

**REGULATION.** The provision of generation and load response capability, including capacity, energy, and MANEUVERABILITY, that responds to automatic controls issued by the BALANCING AUTHORITY.

**LOAD FOLLOWING.** The provision of generation and load response capability, including capacity, energy, and MANEUVERABILITY, that is dispatched within a scheduling period by the BALANCING AUTHORITY.

**CONTINGENCY RESERVE.** The provision of capacity deployed by the BALANCING AUTHORITY to reduce AREA CONTROL ERROR to meet the Disturbance Control Standard (DCS) and other NERC and Regional Reliability Council contingency requirements. CONTINGENCY RESERVES are composed of CONTINGENCY RESERVE–SPINNING and CONTINGENCY RESERVE–SUPPLEMENTAL.

**REACTIVE POWER SUPPLY FROM GENERATION SOURCES.** The provision of reactive capacity, reactive energy, and responsiveness from IOS RESOURCES, available to control voltages and support operation of the BULK ELECTRIC SYSTEM.

**FREQUENCY RESPONSE.** The provision of capacity from IOS RESOURCES that deploys automatically to stabilize frequency following a significant and sustained frequency deviation on the INTERCONNECTION.

**SYSTEM BLACK START CAPABILITY.** The provision of generating equipment that, following a system
blackout, is able to: 1) start without an outside electrical supply; and 2) energize a defined portion of the transmission system. **SYSTEM BLACK START CAPABILITY** serves to provide an initial startup supply source for other system capacity as one part of a broader restoration process to re-energize the transmission system.

The six IOS above are a core set of IOS, but are not necessarily an exhaustive list of IOS. Other **BULK ELECTRIC SYSTEM** reliability services provided by generators or loads could potentially be defined as IOS.

The following related terms are used in this IOS Reference Document:

**BALANCING AREA.** An electrical system bounded by interconnection (tie-line) metering and telemetry. It controls generation (and controllable loads) directly to maintain its interchange schedule with other BALANCING AREAS and contributes to frequency regulation of the INTERCONNECTION.

**BALANCING AUTHORITY.** An entity that: integrates resource plans ahead of time, and maintains load-interchange-generation balance within its metered boundary and supports system frequency in real time.

**BULK ELECTRIC SYSTEM.** The aggregate of electric generating plants, transmission lines, and related equipment. The term may refer to those facilities within one electric utility, or within a group of utilities in which the transmission facilities are interconnected.

**CONTINGENCY RESERVE – SPINNING.** The portion of CONTINGENCY RESERVE provided from IOS RESOURCES consisting of:

- Generation synchronized to the system and fully available to serve load within $T_{DCS}$ minutes of the contingency event; or
- Load fully removable from the system within $T_{DCS}$ minutes of the contingency event.

**CONTINGENCY RESERVE – SUPPLEMENTAL.** The portion of CONTINGENCY RESERVE provided from IOS RESOURCES consisting of:

- Generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within $T_{DCS}$ minutes of the contingency event; or
- Load fully removable from the system within $T_{DCS}$ minutes of the contingency event.

**DEPLOY.** To authorize the present and future status and loading of resources. Variations of the word used in this IOS Reference Document include DEPLOYMENT and DEPLOYED.

**DYNAMIC TRANSFER.** The provision of the real-time monitoring, telemetering, computer software, hardware, communications, engineering, energy accounting (including inadvertent interchange), and administration required to electronically move all or a portion of the real energy services associated with a generator or load out of one BALANCING AREA into another.

**INTERCONNECTED OPERATIONS SERVICE (IOS).** A service (exclusive of basic energy and transmission services) that is required to support the reliable operation of interconnected BULK ELECTRIC SYSTEMS.

**INTERCONNECTION.** Any one of the three major electric system networks in North America: Eastern, Western, and ERCOT.

**IOS SUPPLIER.** An entity that offers to provide, or provides, one or more IOS.
**IOS RESOURCE.** The physical element(s) of the electric system, which is (are) capable of providing an IOS. Examples of an IOS RESOURCE may include one or more generating units, or a portion thereof, and controllable loads.

**LOAD-SERVING ENTITY.** An entity that: Secures energy and transmission (and related generation services) to serve the end user.

**MANEUVERABILITY.** The ability of an IOS RESOURCE to change its real- or reactive-power output over time. MANEUVERABILITY is characterized by the ramp rate (e.g., MW/minute) of the IOS RESOURCE and, for REGULATION, its acceleration rate (e.g., MW/minute$^2$).

**OPERATING AUTHORITY**. An entity that:
1. Has ultimate accountability for a defined portion of the BULK ELECTRIC SYSTEM to meet one or more of three reliability objectives – generation/demand balance, transmission security, and/or emergency preparedness; and
2. Is accountable to NERC and one or more Regional Reliability Councils for complying with NERC and Regional Policies; and
3. Has the authority to control or direct the operation of generating resources, transmission facilities, or loads, to meet these Policies.

**OPERATING RESERVE.** That capability above firm system demand required to provide REGULATION, load forecasting error, equipment forced and scheduled outages, and other capacity requirements.

### 1.3 IOS Are Building Blocks of Reliability

IOS are the elemental ‘reliability building blocks’ from generation (and sometimes load) necessary to maintain BULK ELECTRIC SYSTEM reliability. These ‘reliability building blocks’ have historically been provided by integrated utilities, configured as CONTROL AREAS, using internally owned resources. In contrast, in many areas of North American today, the introduction of competitive electricity markets has resulted in restructuring to separate transmission and generation functions, as well as other traditionally integrated functions. Increasingly, some of the entities responsible for reliability of BULK ELECTRIC SYSTEMS do not own all of the resources necessary for reliability but must obtain these resources, in particular generator-provided services, through a market process or through commercial arrangements.

This IOS Reference Document identifies six basic reliability services from generation (and sometimes load) that must be provided, regardless of regulatory environment, market structure, or organizational framework, to ensure BULK ELECTRIC SYSTEM reliability. These functions are the raw materials that OPERATING AUTHORITIES must assemble for deployment on a regional and interconnection basis to achieve BULK ELECTRIC SYSTEM reliability.

The IOS presented in this paper were chosen as such because their unique physical characteristics lend themselves to separate measurement methods and reliability criteria. These IOS can be combined in various ways to support commercial relationships – simply because a function is an IOS should not naturally lead to the conclusion that the marketplace should buy and sell that specific IOS separately.

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1 Examples of OPERATING AUTHORITIES, as used in the IOS Reference Document, include the following authorities defined in the NERC Functional Model: RELIABILITY AUTHORITY, BALANCING AUTHORITY, TRANSMISSION OPERATOR, TRANSMISSION SERVICE PROVIDER, and INTERCHANGE AUTHORITY. The IOS Reference Document uses the term OPERATING AUTHORITY when the reference generally applies to more than one functional authority. A specific functional authority is identified when the reference applies only to that authority.
Figure 1 illustrates the relationship between the IOS and reliability objectives. Some of the ‘reliability building blocks’ from generation are used to achieve generation and load balance, which is fundamental to maintaining a stable BULK ELECTRIC SYSTEM and INTERCONNECTION frequency within defined limits. These generation and demand balancing IOS are REGULATION, LOAD FOLLOWING, and CONTINGENCY RESERVE.

Other IOS are used to maintain a secure transmission network. REACTIVE SUPPLY FROM GENERATION SOURCES and FREQUENCY RESPONSE are examples of IOS for system security.

Finally, IOS can be used for emergency preparedness and restoration, such as the IOS SYSTEM BLACK START CAPABILITY.

![Figure 1 – IOS as Reliability Building Blocks](image-url)
Section 2. Description of IOS

2.1 Generation and Demand Balancing IOS

BALANCING AUTHORITY Obligations

In their simplest form, generation and demand balancing IOS are capacity and the ability to raise and lower output or demand in response to control signals or instructions under normal and post-contingency conditions. Generators, controllable loads, or storage devices may provide these capabilities. Energy may also be delivered by a resource as a byproduct of providing the balancing capability.

The BALANCING AUTHORITY aggregates and deploys resources providing these services to meet the BALANCING AREA generation and demand balancing obligations, defined by control performance standards in NERC Operating Policy 1. These resources may supply a diverse mix of IOS, since balancing occurs in different time horizons and under both pre- and post-contingency conditions.

Section E of NERC Operating Policy 1 requires that a BALANCING AREA meet the following criteria:

- Control Performance Standard 1 (CPS1). Over a year, the average of the clock-minute averages of a BALANCING AREA’s ACE divided by –10B (B is the BALANCING AREA frequency bias) times the corresponding clock-minute averages of the INTERCONNECTION’S frequency error shall be less than a specific limit;
- Control Performance Standard 2 (CPS2). The ten-minute average ACE must be within a specific limit \( L_{10} \) at least 90% of the time within each month; and
- Disturbance Control Standard (DCS). For reportable disturbances, the ACE must return either to zero or to its pre-disturbance level within a specified disturbance recovery time (defined in IOS Reference Document as \( T_{DCS} \) minutes) following the start of a disturbance.

Operating Reserves

Policy 1 also requires a BALANCING AUTHORITY to provide a level of OPERATING RESERVES sufficient to account for such factors as forecasting errors, generation and transmission equipment unavailability, system equipment forced outage rates, maintenance schedules, regulating requirements, and load diversity. Policy 1 states that OPERATING RESERVES consist of REGULATION and CONTINGENCY RESERVES, and that OPERATING RESERVES can be used for the reasons listed above. OPERATING RESERVES may be comprised of: (1) available capacity from resources providing REGULATION and LOAD FOLLOWING services, (2) CONTINGENCY RESERVES, (3) available FREQUENCY RESPONSE capacity, and (4) load-serving reserves or backup supply.

Load-serving reserves are the responsibility of a LOAD-SERVING ENTITY. They are designed to account for errors in forecasting, anticipated and unanticipated generation/resource and transmission outages, and maintenance schedules that impact the delivery of energy to the LOAD-SERVING ENTITY. These reserves support the reliability of individual LOAD-SERVING ENTITIES, rather than the interconnected BULK

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2 NERC is in the process of developing a new standard title “Balance Resources and Demand” that incorporates CPS1, CPS2, and DCS as measures. The IOS Reference Document refers to the standards as they are currently defined in NERC Operating Policy 1.

3 The disturbance recovery time is defined in the IOS Reference Document as a variable \( T_{DCS} \) to recognize that the specified recovery time stated in Policy 1 may change.
ELECTRIC SYSTEMS. As a result, they are not an IOS and are not addressed in this IOS Reference Document.

Overview of Resource and Demand Balancing IOS

Table 1 summarizes the IOS necessary to provide resource and demand balancing services and shows the reliability objective associated with each.

<table>
<thead>
<tr>
<th>IOS</th>
<th>Reliability Objective</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Normal operating state</td>
</tr>
<tr>
<td>REGULATION</td>
<td>Follow minute-to-minute differences between resources and demand.</td>
</tr>
<tr>
<td>LOAD FOLLOWING</td>
<td>Follow resource and demand imbalances occurring within a scheduling period.</td>
</tr>
<tr>
<td>FREQUENCY RESPONSE⁴</td>
<td>Arrest deviation from scheduled frequency.</td>
</tr>
<tr>
<td>CONTINGENCY RESERVES</td>
<td>Restore resource and demand balance, usually after a contingency.</td>
</tr>
<tr>
<td>SPINNING</td>
<td>Restore resource and demand balance after a contingency.</td>
</tr>
<tr>
<td>SUPPLEMENTAL</td>
<td></td>
</tr>
</tbody>
</table>

Figure 2 compares the use and deployment period of the resource and demand balancing IOS.

<table>
<thead>
<tr>
<th>DEPLOYMENT Period</th>
<th>REGULATION</th>
<th>LOAD FOLLOWING</th>
</tr>
</thead>
<tbody>
<tr>
<td>Continuous</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Post Contingency</td>
<td></td>
<td></td>
</tr>
<tr>
<td>FREQUENCY RESPONSE</td>
<td></td>
<td></td>
</tr>
<tr>
<td>CONTINGENCY RESERVE - SPINNING</td>
<td></td>
<td></td>
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<tr>
<td>CONTINGENCY RESERVE - NON-SPINNING</td>
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</tr>
</tbody>
</table>

Figure 2 – Deployment Period for Resource and Demand Balancing IOS

Description of REGULATION AND LOAD FOLLOWING

REGULATION and LOAD FOLLOWING require similar capabilities and are addressed together in this IOS Reference Document. A major difference is that LOAD FOLLOWING resources are deployed over a longer period.

⁴In this IOS Reference Document, FREQUENCY RESPONSE is treated as an INTERCONNECTION security function, rather than a generation and demand balancing function. It is shown in Table 2 and Figure 2 only for the purpose of showing the deployment times relative to those of the resource and demand balancing IOS.
time horizon and over a generally wider range of output than resources providing REGULATION. The LOAD FOLLOWING burden imposed by individual loads tends to be highly correlated while the REGULATION burden tends to be largely uncorrelated.

REGULATION provides for resource and demand balancing in a time frame of minutes. The BALANCING AUTHORITY continuously determines the required changes (up and down) to the real power output of regulating resources to correct ACE to within CPS bounds.

LOAD FOLLOWING addresses longer-term changes in demand within scheduling periods. LOAD FOLLOWING resources, under automatic or manual control, chase (and to an extent anticipate) the longer-term variations within a scheduling period. Figure 3 distinguishes the time horizons of REGULATION AND LOAD FOLLOWING IOS.

![Figure 3 – REGULATION and LOAD FOLLOWING](image)
Description of CONTINGENCY RESERVE

In addition to committing and controlling resources to ensure continuous balance between resources and demand, NERC Policy 1 requires a BALANCING AUTHORITY to return resources and demand to a balanced state (or at least to the same level of imbalance as the pre-contingency state) within ten minutes following a contingency. CONTINGENCY RESERVE provides standby capability to meet this requirement.

Following a contingency, FREQUENCY RESPONSE will immediately begin to arrest the frequency deviation across the INTERCONNECTION. Within the affected BALANCING AREA, resources providing REGULATION will begin to adjust outputs within seconds in response to signals from the BALANCING AREA’s AGC. In addition, the BALANCING AUTHORITY may deploy, if necessary, CONTINGENCY RESERVE – SPINNING and SUPPLEMENTAL. These reserves are used to restore the pre-contingency resource and demand balance, FREQUENCY RESPONSE capacity, and REGULATION capacity. In all cases, the CONTINGENCY RESERVE must be sufficiently activated so that within $T_{DCS}$ (or less) the pre-contingency resource/demand balance and FREQUENCY RESPONSE capacity are restored. Delivery of these reserves must be sustainable for the minimum reserve deployment period.

The time line below in Figure 4 graphically shows the operating relationship between FREQUENCY RESPONSE, CONTINGENCY RESERVE and an individual LOAD-SERVING ENTITY’S reserve or backup supply.

![Figure 4 – Operating Reserve Timeline](image)

Coordinated post-contingency operating plans are necessary to ensure BALANCING AUTHORITIES are able to deploy and restore CONTINGENCY RESERVE in a timely manner. These plans must outline the reserve obligations of BALANCING AUTHORITIES, other OPERATING AUTHORITIES, and LOAD-SERVING ENTITIES. These arrangements should delineate when and how schedules will be curtailed, which BALANCING AUTHORITY is responsible to deploy CONTINGENCY RESERVE, and when and how replacement schedules, if any, will be implemented.

Transmission Losses
Although the previous discussion focused on the mismatch between resources and demand due to randomly varying loads as well as control and scheduling errors, the losses associated with use of the transmission system must also be recognized. Real power losses are actually another type of demand and, if not compensated for, can cause a deficiency in reserves and system frequency degradation, thus threatening system reliability.

All electrical flows impact system losses. This includes transmission customer uses, native load uses, parallel flows, and other uses. All scheduled users of the transmission system are responsible for providing losses associated with their use of the system. The BALANCING AUTHORITY is responsible to balance total system demand, including losses.

The difference in real-time between actual system losses and resources scheduled to supply system losses is provided by REGULATION and LOAD FOLLOWING. For this reason, the IOS Reference Document does not treat losses as a separate IOS. Instead losses are handled in the market, through scheduling processes, in accordance with transmission tariffs and contracts. Any differences between scheduled and actual losses are addressed through REGULATION and LOAD FOLLOWING, or possibly through energy imbalance measures, if a transmission customer is delivering energy to compensate for losses.

### Energy Imbalance

Energy and scheduling imbalances are measures of how well a transmission customer is meeting its balancing obligations at a specific point or points on the system. Such imbalances are calculated as the difference between actual and scheduled energy at a point of receipt or point of delivery over a scheduling period.

The provision of resource and demand balancing in a pre-contingency state for a transmission customer is done through the use of scheduled delivery of resources to serve the transmission customer’s load, along with the provision of REGULATION and LOAD FOLLOWING.

Although existing transmission tariffs may treat energy imbalance as a service, the IOS Reference Document considers energy imbalance, including scheduling imbalances with generators, as energy mismatch measurements. Energy imbalance is a measure of historical performance averaged over a time period. IOS are capabilities that are deployed in the present and future to meet reliability objectives. Both energy imbalance and IOS can be measured, and can have reliability criteria and economic terms. However, energy imbalance only describes past performance, while IOS are services that may be deployed now and in the future for reliability purposes.

#### 2.2 Bulk Electric System Security IOS

System security refers to the ability of BULK ELECTRIC SYSTEMS to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

Two fundamental capabilities needed to maintain BULK ELECTRIC SYSTEM security are the ability to:

1. Maintain system voltages within limits to maintain INTERCONNECTION reliability under normal and emergency conditions. This is accomplished by coordinating the following

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5 Refer to Operating Policy 2 B and Planning Policy I D for Control Area standards related to voltage control.
minimum components of transmission system voltage control:

- Load power factor correction;
- Transmission reactive compensation (capacitors, reactors, static var compensators, etc.);
- Generator interconnection requirements with the transmission provider (relay and control, power factor, voltage, etc.);
- OPERATING AUTHORITY coordination; and
- REACTIVE POWER SUPPLY FROM GENERATION SOURCES (IOS)

2. Automatically and rapidly arrest frequency excursions due to contingencies on BULK ELECTRIC SYSTEMS. This capability constitutes the FREQUENCY RESPONSE IOS.

REACTIVE POWER SUPPLY FROM GENERATION SOURCES

REACTIVE POWER SUPPLY FROM GENERATION SOURCES comprises the following essential capabilities from generators (and possibly some loads): reactive capacity, reactive energy, dynamic and fast-acting responsiveness through the provision and operation of an Automatic Voltage Regulator (AVR), and the ability to follow a voltage schedule. REACTIVE POWER SUPPLY FROM GENERATION SOURCES is used by the OPERATING AUTHORITY to maintain system voltages within established limits, under both pre- and post-contingency conditions, and thereby avoid voltage instability or system collapse.

Interconnection Requirements – Reactive

In addition to the use of this generation-based IOS, the OPERATING AUTHORITY maintains transmission security through the coordinated use of static reactive supply devices throughout the system, and may develop and impose reactive criteria on LOAD-SERVING ENTITIES. Requirements for the non-generator components are addressed in NERC, Regional Reliability Council, and local standards and interconnection requirements.

As an example, minimum interconnection requirements include NERC Planning Standard III C S1, which states: “All synchronous generators connected to the interconnected transmission systems shall be operated with their excitation system in the automatic voltage control mode unless approved otherwise by the transmission system operator.” The intent is that there be no supplementary excitation control (reactive power or power factor control) that limits emergency reactive power output to less than reactive power capability.

Generator power factor and voltage regulation standards can be a condition of interconnection to satisfy area or local system voltage conditions. Voltage regulating capacity and capabilities that are provided to meet minimum interconnection requirements do not imply that those generators are qualified IOS SUPPLIERS.

FREQUENCY RESPONSE

FREQUENCY RESPONSE is the capability to change, with no manual intervention, an IOS RESOURCE’s real power output in direct response to a deviation from scheduled frequency.

The need for FREQUENCY RESPONSE extends beyond the boundaries of a BALANCING AREA to meet the reliability needs of the INTERCONNECTION. Hence it is aligned with a transmission security objective rather than the resource and demand balancing objective. FREQUENCY RESPONSE is not required to meet the BALANCING AREA needs related to DCS. CONTINGENCY RESERVE is used for that purpose.
FREQUENCY RESPONSE is achieved through an immediate governor response to a significant change in INTERCONNECTION frequency. The cumulative effect of the governor response within the INTERCONNECTION provides an INTERCONNECTION-wide response to a frequency deviation (i.e., all BALANCING AREAS will “see” a frequency change and contribute their frequency response in proportion to the frequency change). This governor action arrests the frequency deviation and allows other slower responding control actions to effectively restore system frequency and affected BALANCING AREA’s ACE.

2.3 Emergency Preparedness

Emergency preparedness refers to the measures taken to prepare for the rare occasions when all or a major portion of a BULK ELECTRIC SYSTEM or INTERCONNECTION is forced out of service. When this occurs, the capability must exist to restore normal operations as quickly as possible. This is called system restoration. System restoration requires:

- **SYSTEM BLACK START CAPABILITY** – Generating units that can start themselves without an external electricity source and can then energize transmission lines and restart other generating units;
- Non-black start generating units that can quickly return to service after offsite power has been restored to the station and can then participate in further restoration efforts;
- Transmission system equipment, controls, and communications (including ones that can operate without grid power), and field personnel to monitor and restore the electrical system after a blackout;
- System control equipment and communications (including ones that can operate without grid power); and
- Personnel to plan for and direct the restoration operations after such a blackout.

The IOS Reference Document deals only with the first of these five aspects of system restoration, as it is a critical reliability service that must be provided by generation resources. Other NERC Planning and Operating Standards address other elements of this service. NERC Planning Standard 4A, System Black Start Capability, states that: “Following the complete loss of system generation (blackout), it will be necessary to establish initial generation that can supply a source of electric power to other system generation and begin system restoration.” These initiating generators are referred to as **SYSTEM BLACK START CAPABILITY**.

NERC Operating Policy 6 D, Operations Planning – System Restoration, requires: Each OPERATING AUTHORITY and Region shall develop and periodically update a logical plan to reestablish its electric system in a stable and orderly manner in the event of a partial or total shutdown of the system. For further reference, see Policy 5 E, Emergency Operations-System Restoration.
Section 3. Sample IOS Standards

3.1 Sample General Requirements

Introduction

Section 3.1 provides a sample of general requirements that may be applicable for all IOS. These sample general requirements establish a framework of responsibilities for:

- Development of IOS specifications and metrics for certification and performance evaluation.
- The provision of IOS, including planning, aggregation, and deployment.
- Monitoring and verification of IOS.

Specific sample standards for each IOS are provided in the remaining parts of Section 3. The sample standards throughout Section 3 are grouped into two main subheadings according to the type of entity to which the standards may apply: OPERATING AUTHORITY or IOS SUPPLIER.

The sample standards in the IOS Reference Document stipulate that the required amounts of each IOS are contingent upon the characteristics of the regional or local BULK ELECTRIC SYSTEMS. Such specific regional or local requirements should be developed through a process that is a) open to and inclusive of all market participants, and b) in accordance with the prevailing regional processes for standards development.

The sample IOS SUPPLIER requirements are intended to apply to all IOS RESOURCES regardless of ownership.

Sample General Requirements – OPERATING AUTHORITY

The statements below are provided for information only and do not infer mandatory requirements or a description of industry practices.

1. **Provision of IOS.** The OPERATING AUTHORITY shall assure sufficient IOS are arranged, provided, and deployed to meet NERC, Regional Reliability Council, and local planning and operating standards.

2. **Specify IOS Requirements.** The OPERATING AUTHORITY shall determine IOS requirements through an open and inclusive process that is consistent with regulatory requirements, is coordinated at a regional level, includes market stakeholders, and allows for dispute resolution. Regional and local IOS requirements include but are not limited to:

   2.1. The quantity, response time, duration, location and other criteria for each IOS as necessary to meet NERC, Regional Reliability Council, and local planning and operating standards.

   2.2. Written procedures for the arrangement, provision, and deployment of IOS.

   2.3. Metering requirements, consistent with established industry practices, for IOS RESOURCES.
2.4. Voice and data communication requirements associated with provision and delivery of IOS.

2.5. Transmission service requirements for delivery of each IOS.

3. Changing System Conditions. IOS requirements and procedures shall be adapted as necessary to maintain system reliability in response to current or expected system conditions.

4. Publication of IOS Requirements. The OPERATING AUTHORITY shall maintain publicly available documents specifying IOS requirements and procedures.

5. Performance Verification. The OPERATING AUTHORITY shall monitor the actual performance of IOS RESOURCES under normal and/or disturbance conditions to verify the IOS RESOURCE meets published performance criteria.

Sample General Requirements – IOS SUPPLIER

The statements below are provided for information only and do not infer mandatory requirements or a description of industry practices.

7. IOS RESOURCE Capabilities. An IOS SUPPLIER shall provide IOS RESOURCES which are:

7.1. Able to deliver the stated IOS capabilities to the BULK ELECTRIC SYSTEM.

7.2. Responsive to the instructions and controls of the OPERATING AUTHORITY, as specified for each IOS and consistent with previously agreed upon terms and conditions between the IOS SUPPLIER and OPERATING AUTHORITY.

8. IOS RESOURCE Certification. The capabilities of IOS RESOURCES shall be certified according to the defined minimum criteria. (See IOS Reference Document Section 4.3 for certification criteria.)

9. Metering. An IOS SUPPLIER shall provide and maintain metering to measure IOS capabilities and performance, as specified by published IOS requirements.

10. Voice and Data Communications. An IOS SUPPLIER shall provide and maintain voice and data communications, as specified by published IOS requirements, to enable:

10.1. IOS RESOURCES to respond to the instructions or controls of the OPERATING AUTHORITY.

10.2. OPERATING AUTHORITIES to monitor the capabilities and verify the performance of IOS RESOURCES.

11. Provision of IOS. An IOS SUPPLIER shall, as soon as practicable, notify the OPERATING AUTHORITY of any changes in the capability to provide the service or meet stated obligations.

12. Performance Verification. Upon request, an IOS SUPPLIER shall provide information to the OPERATING AUTHORITY necessary to verify performance, in accordance with published IOS requirements and procedures. All IOS SUPPLIERS, including OPERATING AUTHORITIES, which are
IOS SUPPLIERS, shall maintain and provide verifiable data for certification purposes.

13. **Concurrent Commitment of IOS Resources.** An IOS SUPPLIER may make concurrent commitments of an IOS RESOURCE’s capability to provide IOS (for example providing recallable energy and CONTINGENCY RESERVE – SUPPLEMENTAL), if the following conditions are met:

13.1. The practice is disclosed, in advance, to the OPERATING AUTHORITY(IES) involved; and

13.2. The arrangements do not conflict with meeting the IOS SUPPLIER’s obligations, nor the provision requirements of each concurrently committed IOS. For example, the same capacity for CONTINGENCY RESERVE may not be concurrently used for REGULATION.

### 3.2 Sample REGULATION and LOAD FOLLOWING Requirements

**Sample Requirements – BALANCING AUTHORITY**

The statements below are provided for information only and do not infer mandatory requirements or a description of industry practices.

1. **Written Requirements.** The BALANCING AUTHORITY shall determine the IOS requirements for REGULATION and LOAD FOLLOWING in accordance with Requirement 2 of Section 3.1 – Operating Authority Sample Requirements. These requirements may include the amount, location, and response capabilities of IOS RESOURCES.

2. **Provision.** The BALANCING AUTHORITY shall assure sufficient REGULATION and LOAD FOLLOWING capabilities are arranged, provided, and deployed to meet NERC, applicable Regional Reliability Council, and local planning and operating standards.

3. **Deployment.** The BALANCING AUTHORITY shall direct the current and future loading of the portion of IOS RESOURCES providing REGULATION or LOAD FOLLOWING. Loading refers to the energy delivery of the IOS RESOURCE, within the operating constraints committed by the IOS SUPPLIER.

4. **IOS SUPPLIER Performance Monitoring.** The BALANCING AUTHORITY shall monitor the REGULATION and LOAD FOLLOWING performance of IOS SUPPLIERS. The BALANCING AUTHORITY shall maintain records of IOS SUPPLIER performance and data used to calculate performance.
Sample Requirements – IOS SUPPLIER

The statements below are provided for information only and do not infer mandatory requirements or a description of industry practices.

5. **Declaration of REGULATION Response Capability.** An IOS SUPPLIER that has agreed to provide REGULATION shall declare to the BALANCING AUTHORITY the IOS RESOURCE’s:

   5.1. Maximum and minimum outputs that define the REGULATION range of the IOS RESOURCE.

   5.2. MANEUVERABILITY characteristics including ramp up and ramp down limit, minimum time between requests for control changes, and maximum and minimum acceleration.

6. **Declaration of LOAD FOLLOWING Response Capability.** An IOS SUPPLIER providing LOAD FOLLOWING shall declare to the BALANCING AUTHORITY the IOS RESOURCE’s:

   6.1. Maximum and minimum outputs that define the LOAD FOLLOWING range of the IOS RESOURCE.

   6.2. The ramp rate and acceleration of the IOS RESOURCE.

   6.3. The minimum time period between requests for load changes.

7. **REGULATION Response.** An IOS RESOURCE that is offered to provide REGULATION shall automatically change the real power output in response to the controls supplied by the BALANCING AUTHORITY, subject to the agreed upon REGULATION capabilities of the IOS RESOURCE.

8. **LOAD FOLLOWING Response.** An IOS RESOURCE that is offered to provide LOAD FOLLOWING shall increase or decrease its real power output in response to instructions from the BALANCING AUTHORITY, subject to the agreed upon LOAD FOLLOWING capabilities of the IOS RESOURCE.

9. **Metering and Communication.** An IOS SUPPLIER offering to provide REGULATION or LOAD FOLLOWING shall meet the following minimum metering and communication requirements:

   9.1. The IOS RESOURCE shall have a BALANCING AUTHORITY approved data communication service between the IOS RESOURCE control interface and the BALANCING AREA.

   9.2. The IOS RESOURCE shall have a BALANCING AUTHORITY approved voice communication service to provide both primary and alternate voice communication between the BALANCING AUTHORITY and the operator controlling the IOS RESOURCE.
9.3. The IOS SUPPLIER shall provide to the BALANCING AUTHORITY real-time telemetry of the real power output of each IOS RESOURCE. The update frequency for REGULATION and LOAD FOLLOWING shall be in accordance with the requirements and guides in Operating Policy 1. The availability and reliability of the telecommunications shall comply with Operating Policy 7.

10. REGULATION and LOAD FOLLOWING IOS RESOURCES Outside of the BALANCING AREA. IOS SUPPLIERS providing REGULATION or LOAD FOLLOWING from IOS RESOURCES located in a BALANCING AREA other than the BALANCING AREA in which the load is physically connected, shall be controlled by a DYNAMIC TRANSFER.
3.3. Sample CONTINGENCY RESERVE Requirements

Sample Requirements – BALANCING Authority

The statements below are provided for information only and do not infer mandatory requirements or a description of industry practices.

1. **Written Requirements.** The BALANCING AUTHORITY shall determine the IOS requirements for CONTINGENCY RESERVE – SPINNING, and CONTINGENCY RESERVE – SUPPLEMENTAL in accordance with Requirement 2 of Section 3.1 – Operating Authority Sample Requirements. These requirements may include the amount, location, and response characteristics, allowed overshoot, and the portion of CONTINGENCY RESERVE that must be SPINNING or SUPPLEMENTAL.

2. **Provision.** The BALANCING AUTHORITY shall assure sufficient capabilities for CONTINGENCY RESERVE – SPINNING and SUPPLEMENTAL are arranged, provided, and deployed to meet NERC, applicable Regional Reliability Council, and local operating requirements.

3. **CONTINGENCY RESERVE Dispersion.** CONTINGENCY RESERVES dispersion shall consider the effective use of capacity in an emergency, time required to be effective, transmission limitations, and local area requirements.

4. **Deployment of CONTINGENCY RESERVE – SPINNING AND SUPPLEMENTAL.** The BALANCING AUTHORITY shall direct the loading of IOS RESOURCES that provide CONTINGENCY RESERVE – SPINNING and SUPPLEMENTAL. The BALANCING AUTHORITY shall ensure deployment capability within the required recovery time from disturbance conditions (T_{DCS}) specified in Operating Policy 1. The BALANCING AUTHORITY shall ensure deployment of CONTINGENCY RESERVE is sustainable for a minimum of 30 minutes following the contingency event.

5. **Verification of Performance.** The BALANCING AUTHORITY shall verify that all IOS RESOURCES requested to provide CONTINGENCY RESERVE – SPINNING, and SUPPLEMENTAL do so according to established performance criteria, including reaching the requested amount of real power output within and for the specified time limits.

6. **Restoration of CONTINGENCY RESERVE.** The BALANCING AUTHORITY shall develop clear operating plans and procedures to assure the timely deployment and restoration of CONTINGENCY RESERVE. These plans and procedures shall specify how CONTINGENCY RESERVE shall be restored, for example, how and when schedules are curtailed, replaced, or initiated.

Sample Requirements – IOS SUPPLIER

The statements below are provided for information only and do not infer mandatory requirements or a description of industry practices.

7. **Declaration of CONTINGENCY RESERVE Capability.** An IOS SUPPLIER that has agreed to provide CONTINGENCY RESERVE shall declare to the BALANCING AUTHORITY the IOS RESOURCE’s capabilities.

8. **IOS RESOURCE Response.** An IOS RESOURCE offered to provide CONTINGENCY RESERVES shall be:
8.1. Responsive to the instructions and/or variable scheduled output supplied by the BALANCING AUTHORITY.

8.2. Continuously synchronized to the system, when providing CONTINGENCY RESERVES – SPINNING SERVICE.

8.3. Available for redeployment after the pre-arranged elapsed time as specified by the IOS SUPPLIER.

9. **Provision of CONTINGENCY RESERVES.** In response to the instructions of the BALANCING AUTHORITY, and subject to the declared capabilities of the IOS RESOURCE, the IOS RESOURCE shall:

9.1. Provide between 100% and the allowed overshoot of the stated amount (MW) of CONTINGENCY RESERVE – SPINNING within \( T_{DCS} - X \) minutes of a call by the BALANCING AUTHORITY requesting CONTINGENCY RESERVE. \( X \) is the number of minutes agreed to in advance by the BALANCING AUTHORITY and IOS SUPPLIER that allows for the BALANCING AUTHORITY to respond to a contingency and call for deployment of CONTINGENCY RESERVE.

9.2. Maintain between 100% and the allowed overshoot of the stated amount (MW) of CONTINGENCY RESERVE – SPINNING for at least 15 minutes subsequent to \( T_{DCS} - X \).

9.3. Return to the non-contingency scheduled output (or consumption) +/- 10% of the requested amount of CONTINGENCY RESERVE, within ten minutes of instructions from the BALANCING AUTHORITY to do so. Alternatives to the +/- 10% bandwidth and the ten minute period may be established by the BALANCING AUTHORITY through an open process defined in Requirement 2 - Section 3.1 – OPERATING AUTHORITY Requirements.

10. **Maintaining Reserve Capacity.** An IOS SUPPLIER shall maintain the capacity committed to provide CONTINGENCY RESERVE throughout the commitment period.

11. **Metering and Communication.** An IOS SUPPLIER offering to provide CONTINGENCY RESERVE shall meet the following minimum metering and communication requirements:

11.1. The IOS SUPPLIER shall provide to the BALANCING AUTHORITY real-time telemetry of the real power output of each IOS RESOURCE providing CONTINGENCY RESERVE.

11.2. The IOS RESOURCE shall have a BALANCING AUTHORITY approved data communication service between the IOS RESOURCE control interface and the BALANCING AREA.

11.3. The IOS RESOURCE shall have a BALANCING AUTHORITY approved voice communication service to provide both primary and alternate voice communication between the BALANCING AUTHORITY and the operator controlling the IOS RESOURCE.
3.4 Sample REACTIVE POWER SUPPLY FROM GENERATION SOURCES

Requirements

Sample Requirements – OPERATING AUTHORITY

The statements below are provided for information only and do not infer mandatory requirements or a description of industry practices.

1. Voltage Schedule Coordination. The OPERATING AUTHORITY shall establish, and update as necessary, voltage schedules at points of integration of REACTIVE POWER SUPPLY FROM GENERATION SOURCES, to maintain system voltages within established limits and to avoid burdening neighboring systems. The OPERATING AUTHORITY shall communicate to the IOS SUPPLIER the desired voltage at the point of integration.

2. Reactive Reserves. The OPERATING AUTHORITY shall acquire, deploy, and continuously maintain reactive reserves from IOS RESOURCES, both leading and lagging, adequate to meet contingencies.

3. Telemetry. The OPERATING AUTHORITY shall monitor by telemetry the following data:

3.1. Transmission voltages.

3.2. Unit or IOS RESOURCE reactive power output.

3.3. Unit or IOS RESOURCE Automatic Voltage Regulator (AVR) status for units greater than 100 MW (and smaller units where an identified need exists).

4. NERC Planning Standards. The OPERATING AUTHORITY shall comply with NERC Planning Standards applicable to reactive power capability. These standards require that generation owners and OPERATING AUTHORITIES plan and test reactive power capability.

Sample Requirements – IOS SUPPLIER

The statements below are provided for information only and do not infer mandatory requirements or a description of industry practices.

5. Automatic Voltage Regulator. An IOS RESOURCE shall operate with the unit’s AVR in use during the schedule period in which REACTIVE POWER SUPPLY FROM GENERATION SOURCES is provided, unless specifically directed to operate in manual mode by the OPERATING AUTHORITY, or a need to operate in manual mode is identified for emergency reasons by the IOS SUPPLIER. When the IOS SUPPLIER changes the mode, the IOS SUPPLIER shall promptly inform the OPERATING AUTHORITY.

6. Response to Voltage or Reactive Power Schedule Changes. IOS RESOURCES shall meet, within established tolerances, and respond to changes in the voltage or reactive power schedule established by the OPERATING AUTHORITY, subject to the stated IOS RESOURCE reactive and real power operating characteristic limits and voltage limits.
7. **Reactive Capacity.** IOS RESOURCES shall maintain stated reactive capacity, both leading and lagging. An IOS RESOURCE’s stated lagging reactive capacity shall be supplied without interruption or degradation when subject to sudden and large voltage drops.

8. **Telemetry.** IOS RESOURCES shall provide electronic transfer of real-time information to the OPERATING AUTHORITY:

   8.1. Voltages at the IOS RESOURCE point of delivery to the OPERATING AUTHORITY.

   8.2. IOS RESOURCE reactive power output, and

   8.3. IOS RESOURCE AVR status for units of greater than 100 MW of nameplate capacity (and smaller units where an identified need exists).

### 3.5 Sample FREQUENCY RESPONSE Requirements

**Sample Requirements – BALANCING AUTHORITY**

The statements below are provided for information only and do not infer mandatory requirements or a description of industry practices.

1. **Written Requirements.** The BALANCING AUTHORITY shall determine the IOS requirements for FREQUENCY RESPONSE in accordance with Requirement 2 of Section 3.1 – Operating Authority Sample Requirements. These requirements may include the amount, location, and response characteristics.

2. **Provision.** The BALANCING AUTHORITY shall assure sufficient capabilities for FREQUENCY RESPONSE are arranged, provided, and deployed to meet NERC, applicable Regional Reliability Council, and local operating requirements.

3. **Verification of Performance.** The BALANCING AUTHORITY shall verify that all IOS RESOURCES contracted to provide FREQUENCY RESPONSE do so according to established performance criteria, including reaching the requested amount of real power output within and for the specified time limits.
Sample Requirements – IOS SUPPLIER

The statements below are provided for information only and do not infer mandatory requirements or a description of industry practices.

4. Declaration of FREQUENCY RESPONSE Capability. Prior to providing FREQUENCY RESPONSE, the IOS SUPPLIER shall declare the FREQUENCY RESPONSE capabilities of the IOS RESOURCES.

5. Governor. An IOS RESOURCE providing FREQUENCY RESPONSE capability shall maintain an operable governor system and shall be responsive to system frequency deviations.

6. Maintaining FREQUENCY RESPONSE Capacity. An IOS SUPPLIER shall maintain the governor response capability to provide FREQUENCY RESPONSE throughout the commitment period.

7. Metering and Communication. An IOS SUPPLIER offering to provide FREQUENCY RESPONSE shall have frequency metering and generation output metering sufficient to determine on an after the fact basis that the generator delivered the response required.

3.6 SYSTEM BLACK START CAPABILITY

Sample Requirements – OPERATING AUTHORITY

The statements below are provided for information only and do not infer mandatory requirements or a description of industry practices.

1. Restoration Plans. The OPERATING AUTHORITY shall verify that restoration plans meet NERC, applicable Regional Reliability Council, and local requirements, and provide for adequate SYSTEM BLACK START CAPABILITY.

2. System Black Start Requirements. The OPERATING AUTHORITY shall determine the overall required amount and locations of SYSTEM BLACK START CAPABILITY in a system restoration plan for the coordinated re-energization of the transmission network following a total or partial system blackout.

3. Training and Drills. The OPERATING AUTHORITY shall include IOS RESOURCES providing SYSTEM BLACK START CAPABILITY in the conduct of system-wide training, and drills, as necessary to prepare a coordinated response to a partial or total system blackout condition.

4. Provision of SYSTEM BLACK START CAPABILITY. The OPERATING AUTHORITY shall ensure IOS RESOURCES for SYSTEM BLACK START CAPABILITY are arranged, provided, and deployed as necessary to reenergize the transmission network following a total or partial system blackout.

5. Testing and Verification. The OPERATING AUTHORITY shall schedule random testing or simulation, or both, to verify SYSTEM BLACK START CAPABILITY is operable according to the restoration plan. Testing and verification will be in accordance with established certification criteria. These tests and/or simulations shall ensure that the SYSTEM BLACK START CAPABILITY resources and the transmission system are configured such that the SYSTEM BLACK START CAPABILITY resources are able to energize the appropriate portions of the transmission system, and supply restoration power to the generator(s) or load(s), as required by the restoration plan.
The **SYSTEM BLACK START CAPABILITY** resources must provide frequency and voltage within prescribed limits during line energization and remote load pickup.

### 6. Performance Verification

The **OPERATING AUTHORITY** shall verify the actual performance of **SYSTEM BLACK START CAPABILITY** resources in the event actual system blackout conditions occur.

### Sample Requirements – IOS SUPPLIER

The statements below are provided for information only and do not infer mandatory requirements or a description of industry practices.

### 7. IOS RESOURCE Capabilities

An **IOS SUPPLIER** of **SYSTEM BLACK START CAPABILITY** shall provide the following:

- **7.1.** Capability to start a self-starting unit within a time specified, from an initial dead station and auxiliary bus condition. Alternately, a **SYSTEM BLACK START CAPABILITY** resource may be a generating unit that is able to a) safely withstand the sudden and unplanned loss of synchronization with the **BULK ELECTRIC SYSTEM** and b) maintain generating capacity for a specified period of time.

- **7.2.** Capability of re-energizing, within a time specified, the plant auxiliaries necessary to start one or more additional units, if the **SYSTEM BLACK START CAPABILITY** unit is planned as a cranking source for one or more of these additional units.

- **7.3.** Capability of picking up external load within a specified time.

- **7.4.** Stated MW capacity of the **SYSTEM BLACK START CAPABILITY** unit or units.

- **7.5.** Capability of running the **SYSTEM BLACK START CAPABILITY** unit at stated MW capacity for a specified time from when the unit is started.

- **7.6.** Frequency measurement at the **SYSTEM BLACK START CAPABILITY** unit to support the system restoration plan.

- **7.7.** Frequency responsive capability to sustain scheduled frequency and remain stable during load pickup coordinated by the **OPERATING AUTHORITY** in accordance with the restoration plan.

- **7.8.** Reactive supply and voltage control capability to maintain system voltage within emergency voltage limits over a range from no external load to full external load.

- **7.9.** Participation in training and restoration drills coordinated by the **OPERATING AUTHORITY**.

- **7.10.** Provision of voice and data communications with the **OPERATING AUTHORITY**, capable of operating without an external AC power supply for a specified time.
Section 4. Methods for IOS Performance Measurement and Certification

4.1 Introduction

This Section offers metrics for measuring the performance of IOS RESOURCES and certifying IOS-related capabilities. The metrics focus on the key parameters needed for reliability and test or measure these characteristics as precisely and efficiently as possible. The metrics described are examples of measures. Other measures may be valid and appropriate to achieve the same reliability objectives.

Performance measures assess the real-time delivery of a service by an IOS SUPPLIER. By design, the extent of the certification tests is inversely related to the ease of measuring real-time performance. For example, the certification test for the REGULATION is quite simple because REGULATION is delivered on a continuous basis. On the other hand, the certification test for the SYSTEM BLACK START CAPABILITY is more extensive because this service is rarely delivered, and, therefore, cannot routinely be measured. IOS that are deployed only occasionally (e.g., CONTINGENCY RESERVE) have a certification test that is more extensive than REGULATION but simpler than that for SYSTEM BLACK START CAPABILITY.

Performance measures can be monitored at the IOS SUPPLIER (i.e., aggregated) level. This allows the IOS SUPPLIER to meet performance requirements in a flexible manner while holding the IOS SUPPLIER accountable for the aggregate performance of its individual IOS RESOURCES. Certification requirements also potentially allow for a group or portfolio of physical assets to be certified in aggregate. However, if the IOS RESOURCES that comprise the portfolio are modified to the extent that the certified capabilities are affected, then re-certification should be necessary.

The performance metrics presented in this IOS Reference Document were developed to meet three criteria:

- Support reliability objectives of the OPERATING AUTHORITY (e.g., meet Policy 1 requirements for CPS and DCS);
- Be technically justified; and
- Operate well in a variety of regulatory frameworks and market structures and conditions.

Each performance metric includes three components. The measure (e.g., area control error) identifies the characteristic to be measured (analogous to miles per hour for a highway speed limit). The criteria bound the measure (e.g., CPS1 and 2 for area control error or 65 miles per hour for a speed limit). Finally, the metric may include conditions under which the measurements apply (e.g., the Policy 1 DCS measure applies only after a major contingency occurs or speed limits differ between rural freeways and urban roads). The criteria numbers are proposed as a starting point, and will likely need to be changed with experience.

4.2 Performance Measurement Methods

REGULATION and LOAD FOLLOWING Sample Performance Measures

IOS RESOURCES providing REGULATION and LOAD FOLLOWING service deliver capacity, MANEUVERABILITY, and energy to the BALANCING AUTHORITY. The measurement methods described below are intended to determine if sufficient capacity, maneuverability, and energy have been delivered
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to maintain reliability.

The deviation between the output instructed by the BALANCING AUTHORITY, subject to the declared capabilities of the IOS RESOURCE, and the actual output of the IOS RESOURCE is defined as the SUPPLIER CONTROL ERROR (SCE). Each IOS SCE must be bounded within the SCPS1 and SCPS2 criteria as defined below.

Figure 5 below demonstrates the concept of Supplier Control Error as the deviation between instructed output, subject to declared capabilities, and actual output.

Figure 5 – Supplier Control Error: Deviation between Schedule and Actual Output
Figure 6 demonstrates one method for the determination of the scheduled output of a resource.

![Diagram of Figure 6 - Determination of IOS RESOURCE Schedule]

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**Sample IOS Standards**

Version 1.1 Incorporating Functional Model Definitions
March 21, 2002
Figure 7 provides one method for the calculation of SUPPLIER CONTROL ERROR (SCE).

Calculation of Supplier Control Error for Each Unit Performing Load Following and Regulation. This cycle occurs at a predefined time interval. (WPS uses 4 seconds)

**Initial:**
- $Ra = 0$
- $PF = 0$
- Set $J$

**Data:**
- $Pa = $ EMS value

Was Unit on Auto Control?  
$PF > 0$

If Yes, then:
- $SCE = Pa - Ps$
- Accumulate one minute averages of $SCE$ and $PF$
- $Ps = Pa$

**Data:**
- $PF = $ EMS value

Is Unit on Auto Control?  
$PF > 0$

If Yes, then:
- Calculate variable schedule $Ps$ (separate diagram).

End of Current Minute?

Yes
- Calculate one-minute average of $SCE$ and $PF$ and archive.
- Update ten-minute averages of $SCE$ and $PF$. If end of current ten-minute period, archive $|SCE_{10}|$ and calculate SCPS2 limit.

No

Legend
- $Pa$: Power Actual
- $Ps$: Power Scheduled
- $PF$: Unit Participation Factor
- $Ra$: Ramp Rate Actual
- $SCE$: Supplier Control Error
- SCPS: Supplier Control Performance Standard
- J: Jerk Rate

Figure 7 – Determination of Supplier Control Error
Consider that the control signal given to the IOS RESOURCE, subject to the stated capabilities of the IOS RESOURCE, constitute an agreed upon variable schedule. Deviation of actual output from this schedule is the measure of performance (the Supplier Control Error SCE). Compliance is measured with three criteria:

- SCPS1 (an analogy to Policy 1 CPS1)
- Covariance (SCE/pf,ACE) ≤ Limit
- Average (SCE) = 0
- SCPS2 (an analogy to Policy 1 CPS2)

Let us consider, in general terms, the SCPS2 criterion. This criterion requires that the IOS RESOURCE match its actual output to its schedule within a predefined bandwidth for 90% of all measurement periods (10-minute average). In equation form this criterion is described as follows:

\[
SCPS2 = \left( \frac{\text{Number of Compliant Periods}}{\text{Total Number of Periods}} \right) \geq 0.90
\]

\[
\text{Compliant Period when } |SCE_{i10}| \leq L_{10} \star \sqrt{\frac{\text{Participation Factor}}{\sum_i \sqrt{\text{Participation Factor}_i}}}
\]

where: \(|SCE_{i10}|\) is the 10-minute average of SCE

Participation Factor = Response Rate/(Sum of all Response Rates)

\(L_{10}\) is the control area’s CPS2 bound

By requiring the IOS RESOURCE to produce output within a bandwidth around the variable schedule, the SCPS2 criterion measures capacity and maneuverability. Unfortunately, the SCPS2 criterion alone is insufficient. An IOS RESOURCE could consistently produce at the bottom of the bandwidth. This would violate the “energy” attribute of the service. In addition, the IOS RESOURCE could systematically time its errors within the bandwidth to the detriment of reliability: overproducing during times of plenty and under producing during times of shortage. To address these two shortcomings of SCPS2, another criterion is required.

Let us consider, in general terms, the SCPS1 criterion. This criterion requires that the IOS RESOURCE match its actual output to its schedule such that (1) in the long run the scheduled energy equals the actual energy and (2) the timing of the error with respect the control area ACE or the Frequency Error is sufficiently favorable to maintain reliability. In equation form the criteria are described as follows:

\[
\text{Avg}_{\text{month}} (SCE_1) \approx 0
\]

And:

\[
SCF = \text{AVG}(\text{month}) \left[ \frac{SCE_1}{\text{Participation Factor}} \right] \star \left[ \frac{\Delta F_1}{(-10 \star \text{Bias} \star e^2_1)} \right]
\]
or:

\[
SCF = AVG(month) \left[ \left( \frac{SCE_1}{\text{ParticipationFactor}} \right) \ast \left( \frac{ACE_1}{\gamma_1^2} \right) \right]
\]

With:

\[
SCPS1 = (2 - SCF)
\]

where:  
- \( SCE_1 \) is the one minute average Supplier Control Error  
- \( \text{Participation Factor} = \frac{\text{Response Rate}}{\text{Sum of all Response Rates}} \)  
- \( \Delta F \) is the one-minute average frequency error  
- \( \text{Bias} \) is the control area bias  
- \( \varepsilon_1 \) is NERC Policy 1 CPS1 limit  
- \( ACE_1 \) is the control area’s one-minute average area control error  
- \( \gamma_1 \) is the IOS SUPPLIER limit determined by NERC. This value uniquely modifies \( \varepsilon_1 \) for each control area depending on its correlation between \( ACE \) and \( \Delta F \).  

(Note: the specific limit for SCPS1 score is not set forth in this document. Limits between 180% and 200% have been proposed.)

The IOS RESOURCE that is compliant with SCPS1 and SCPS2 operates within a bandwidth, delivers the correct amount of energy, and does not time its errors in a manner detrimental to reliability. This assures that the service attributes of capacity, maneuverability, and energy have been adequately delivered.

Figures 8 and 9 demonstrate the SCPS1 and SCPS2 performance evaluation of 15 units on a sample system.
Figure 8 – Sample Regulation SCPS1 Performance Measures for IOS Resources

Figure 9 - Sample Regulation SCPS2 Performance Measures for IOS Resources
From this information, one may also determine the Regulation participation of individual IOS Resources, as shown in Figure 10.

![Regulation Participation by Unit](image)

**Figure 10 – Sample Determination of Regulation Participation**

Additionally, this information allows one to determine the contribution of Supplier performance to the Control Area’s CPS1 score, shown in Figure 11.

![Allocation of Control Area Performance](image)

**Figure 11 – Sample Determination of Regulation Participation**
CONTINGENCY RESERVE Sample Performance Measures

In response to the instructions of the BALANCING AUTHORITY, and subject to the declared capabilities of the IOS RESOURCE, the IOS RESOURCE shall provide at least 100%, and not greater than 120%, of the stated real power (MW) amount within \((T_{DCS} - X)\) minutes of the receipt of the instructions. The variable “X” is the OPERATING AUTHORITY notification delay. Furthermore, the IOS RESOURCE shall maintain between 100% and 120% of the stated real power (MW) amount for the 20 minutes (or for the CONTINGENCY RESERVE deployment period) following \(T_{DCS}\). Finally, the IOS RESOURCE shall go to within 90% to 110% of its post-contingency scheduled output, subject to the declared capabilities of the IOS RESOURCE, within 10 minutes following instructions from the OPERATING AUTHORITY.

For each IOS RESOURCE providing CONTINGENCY RESERVES, the BALANCING AUTHORITY shall measure and record for the entire duration of the CONTINGENCY RESERVE deployment the one-minute averages of real power output and the instructed output, subject to the declared capabilities of the IOS RESOURCE.

The expected performance criteria are that the IOS RESOURCE loads, sustains, and unloads the stated CONTINGENCY RESERVE amount in MW, within the allowed band-width of 100% to 120%, in the time periods stated in the standard:

- Loads instructed CONTINGENCY RESERVES within \((T_{DCS} - X)\) minutes,
- Sustains instructed CONTINGENCY RESERVES for the 20 minutes following \((T_{DCS} - X)\) minute loading window, and
- Unloads instructed CONTINGENCY RESERVES within 10 minutes of instruction to unload and goes to within 90% to 110% of post-contingency scheduled output, subject to stated capabilities of the IOS RESOURCE.

REACTIVE POWER SUPPLY FROM GENERATION SOURCES Sample Performance Measures

IOS RESOURCES shall meet, within established tolerances, and respond to changes in the voltage or reactive power schedule established by the OPERATING AUTHORITY, subject to the stated IOS RESOURCE reactive and real power operating characteristic limits and voltage limits.

An IOS RESOURCE shall operate with the unit’s AVR in use during the schedule period in which REACTIVE POWER SUPPLY FROM GENERATION SOURCES is provided, unless specifically directed to operate in manual mode by the OPERATING AUTHORITY, or a need to operate in manual mode is identified for emergency reasons by the IOS SUPPLIER.

IOS RESOURCES shall maintain stated reactive capacity, both leading and lagging. An IOS RESOURCE’s stated lagging reactive capacity shall be supplied without interruption or degradation when subject to sudden and large voltage drops.

When an IOS RESOURCE is controlling to a voltage set point under steady state conditions, the IOS RESOURCE Voltage Schedule Error \((V_{\text{ACTUAL}} - V_{\text{SCHEDULE}})\) shall be measured and reported quarterly by the OPERATING AUTHORITY once per each 10-minute period during all scheduling periods in which the IOS RESOURCE is providing the service. 98% of Voltage Schedule Errors Reported in a quarter are within the Voltage Tolerance \((\pm 2\% \text{ of Scheduled})\), subject to the stated capabilities of IOS RESOURCE.

When an IOS RESOURCE is controlling to reactive power output under steady state conditions, the IOS RESOURCE Reactive Power Output Error \((VAR_{\text{ACTUAL}} - VAR_{\text{SCHEDULE}})\) shall be measured and reported quarterly by the OPERATING AUTHORITY once per each 10-minute period during all scheduling periods in
which the IOS RESOURCE is providing the service. 95% of Reactive Power Output Errors Reported in a quarter are within the Reactive Tolerance (± 10% of Scheduled), subject to the stated capabilities of IOS RESOURCE.

The status of the AVR shall be reported quarterly by the IOS SUPPLIER to the OPERATING AUTHORITY for the entirety of all scheduling periods in which the IOS RESOURCE is providing the service. AVR is on and operating automatically at least 98% of the time in which the IOS RESOURCE is providing the service. Percentage is calculated as: (Time AVR is on While Providing IOS) / (Total Time Providing IOS) X 100%.

FREQUENCY RESPONSE Sample Performance Measures

In response to the deviations in system frequency, and subject to the declared capabilities of the IOS RESOURCE such as dead-band and droop, the IOS RESOURCE shall increase or decrease its output according to its stated response characteristic.

For all frequency deviations exceeding the NERC frequency excursion values (Policy 1 epsilon values times an Interconnection-specific factor), the OPERATING AUTHORITY shall measure and record scan rate (e.g. AGC scan rate) values of real power output for the IOS RESOURCE providing FREQUENCY RESPONSE. The OPERATING AUTHORITY shall measure and record the MW data beginning one minute prior to the start of the frequency excursion event until one minute after the start of the frequency excursion event. Compliance is measured by comparing the actual response to the declared frequency response capability.

SYSTEM BLACK START CAPABILITY Sample Performance Measures

The IOS SUPPLIER shall maintain certified SYSTEM BLACK START CAPABILITY IOS RESOURCES, with the declared capacity and capabilities of the IOS RESOURCES, continuously during all periods in which SYSTEM BLACK START CAPABILITY is provided. During a system restoration emergency, the IOS SUPPLIER shall respond to the instructions of the OPERATING AUTHORITY, subject to the declared capacity and capabilities of the SYSTEM BLACK START CAPABILITY IOS RESOURCES.

The following performance measures may be monitored during an emergency: During emergency activation and in response to instructions of the OPERATING AUTHORITY, the IOS RESOURCE:

- Is able to start and synchronize to the power system within the agreed upon time; and
- Is able to provide full declared real and reactive power capabilities.

4.3 Certification Methods

Introduction to Certification Methods

Certification is a means to demonstrate the capability of an IOS Resource to deliver an IOS. Certification increases reliability since it offers assurances to all industry participants that promised capabilities can be deployed and utilized when needed for reliability reasons. In practice, the cost and effort of a certification program needs to be balanced against the reliability impact should the promised capabilities not be delivered when requested, and the probability of delivery shortfalls.

REGULATION and LOAD FOLLOWING may be continuously measured. Therefore no certification requirements are suggested beyond the general certification requirements for all IOS.
This section contains sample certification methods for CONTINGENCY RESERVE, REACTIVE POWER SUPPLY FROM GENERATION SOURCES, FREQUENCY RESPONSE, and SYSTEM BLACK START CAPABILITIES.

OPERATING AUTHORITY Sample IOS Program Certification

The following certification requirements of the OPERATING AUTHORITY should be verified annually through self-assessment and every three years by an entity external to the OPERATING AUTHORITY.

Documentation should be verified to show that the OPERATING AUTHORITY has developed and is maintaining and executing a program to specify and provide IOS in accordance with each OPERATING AUTHORITY requirement in Section 3 of the IOS Reference Document. The following minimum elements should be considered in the review of documentation of the OPERATING AUTHORITY’s IOS program:

1. A detailed plan and procedures to assure sufficient IOS are arranged, provided, and deployed to meet NERC, Regional Reliability Council, and local planning and operating standards.
2. Detailed specifications of the OPERATING AUTHORITY’s requirements for IOS, which have been determined through an open and inclusive process that is consistent with regulatory requirements, is coordinated at a regional level, includes market stakeholders, and allows for dispute resolution. The specifications shall include, but are not limited to:
   2.1. The quantity, response time, duration, location and other criteria for each IOS.
   2.2. Written procedures for the arrangement, provision, and deployment of IOS.
   2.3. Metering requirements.
   2.4. Voice and data communication requirements associated with provision and deployment of IOS.
   2.5. Specification of the transmission service requirements for delivery of each IOS.
3. Procedures for adapting the IOS requirements to maintain system reliability in response to current or expected system conditions.
4. Publication of IOS requirements in publicly available documents that specify the OPERATING AUTHORITY’s IOS requirements and procedures.
5. Procedures for monitoring the actual performance of IOS RESOURCES under normal and/or disturbance conditions to verify the IOS RESOURCE meets published performance criteria.

General Certification – Sample Criteria

The following are sample certification requirements that could apply to all IOS. These requirements would be evaluated by audit or other means of verification.

1. Metering – An IOS SUPPLIER shall provide and maintain metering to measure IOS capabilities and performance, as specified by published IOS requirements.
2. Voice and Data Communications – An IOS SUPPLIER shall provide and maintain voice and data communications, as specified by published IOS requirements, to enable:
2.1. IOS RESOURCES to respond to the instructions or controls of the OPERATING AUTHORITY.

2.2. OPERATING AUTHORITIES to monitor the capabilities and verify the performance of IOS RESOURCES.

CONTINGENCY RESERVE Certification Method

The following is a sample certification test for CONTINGENCY RESERVE – SPINNING and SUPPLEMENTAL:

1. A test for CONTINGENCY RESERVE – SPINNING or SUPPLEMENTAL shall be performed during a continuous 8-hour window agreed upon by the IOS SUPPLIER and the BALANCING AUTHORITY.

2. The BALANCING AUTHORITY shall confirm the date and time of the test with the IOS RESOURCE using both the primary and alternate voice circuits to validate the voice circuits.

3. At any time during the eight-hour window, selected by the BALANCING AUTHORITY, and not previously disclosed to the IOS SUPPLIER, the BALANCING AUTHORITY shall send a signal to the IOS RESOURCE requesting it to provide its declared amount of CONTINGENCY RESERVE – SPINNING OR SUPPLEMENTAL.

4. The IOS RESOURCE output shall be measured as clock-minute average outputs for a) the clock-minute prior to the instructions being received from the BALANCING AUTHORITY; b) the clock-minute following receipt of instructions from the BALANCING AUTHORITY and continuing for $T_{DCS} - X$ minutes (where $T_{DCS}$ is the number of minutes allowed by the Policy 1 Disturbance Control Standard for recovery from a major outage and $X$ is the previously agreed upon time that the BALANCING AUTHORITY requires to identify the need to deploy the reserves and to notify the IOS RESOURCE); c) and for each of the subsequent 19 clock-minutes. All measurements shall be between 100% to $Y\%$ of the declared amount of CONTINGENCY RESERVE, where $Y$ is an INTERCONNECTION-specific factor.

REACTIVE POWER SUPPLY FROM GENERATION SOURCES Certification

The following is a sample certification test for REACTIVE POWER SUPPLY FROM GENERATION SOURCES:

1. The IOS RESOURCE shall perform the unit automatic voltage regulator (AVR) tests, and supply IOS RESOURCE AVR data as required by the NERC Planning Standards “System Modeling Data Requirements, Generation Equipment.” Sections 2B, Measurement 4, and 2B, Measurement 6. The AVR tests will be performed upon initial certification, and periodically at an OPERATING AUTHORITY set time interval no more often than once every five years. The AVR tests are run at a time mutually agreed upon in advance by the IOS SUPPLIER and the OPERATING AUTHORITY.

2. The IOS RESOURCE must verify and maintain its stated reactive capacity, as required by the NERC Planning Standards “System Modeling Data Requirements, Generation Equipment.” Sections 2.B, Measurement 3. This reactive capacity certification test will verify the IOS RESOURCE reactive capacity. The reactive capacity test will be performed upon initial certification, and periodically at an OPERATING AUTHORITY set time interval no more often than once every five years. The reactive capacity test is run at a time mutually agreed upon in advance by the IOS SUPPLIER and the OPERATING AUTHORITY. The test results, as described in 2.B, Measurement 3, shall be communicated to the OPERATING AUTHORITY.
FREQUENCY RESPONSE Certification

The following is a sample certification test for FREQUENCY RESPONSE:

1. The BALANCING AUTHORITY shall confirm the date and time of the test with the IOS RESOURCE. The FREQUENCY RESPONSE test should be performed at a time that is mutually agreed upon by the IOS SUPPLIER and BALANCING AUTHORITY.

2. Because it is impractical to move INTERCONNECTION frequency for test purposes, it is necessary to use simulated frequency excursions outside the allowed deadband to perform a certification test of the IOS RESOURCE. A test frequency signal will be provided to the IOS RESOURCE and the IOS RESOURCE’S response will be measured. The frequency value of the test signal will be calculated to require the full response amount (MW) being certified, based on the IOS RESOURCE’S deadband and droop characteristic. The pre-contingency output (or consumption) of the IOS RESOURCE shall be calculated as the average power recorded for the clock minute prior to the injection of the test frequency signal. After each frequency test signal is injected, the test measurements shall include the MW output (or consumption) ten seconds after the frequency change and the average for each clock-minute from ten seconds through ten minutes following each frequency change. To pass the test, the measured values must differ from the pre-contingency output (or consumption) within the bounds listed in the FREQUENCY RESPONSE criteria.

3. It may be necessary to construct alternative tests for IOS RESOURCES that cannot produce (or consume) real power while connected to a test frequency source. In this case, output (or consumption) may be calculated based upon measured performance of that portion of the system that can be tested (throttle valve position, for example). Testing requirements should be negotiated between the IOS SUPPLIER and the BALANCING AUTHORITY.

SYSTEM BLACK START CAPABILITY Certification

The following sample SYSTEM BLACK START CAPABILITY certification tests are divided into three parts, depending on the frequency of testing required.

**Basic Starting Test** – The basic ability of the IOS RESOURCE to start itself, without support from the grid, should be tested at least once every three years. The test is run during a one-week period mutually agreed upon in advance by the IOS SUPPLIER and OPERATING AUTHORITY. The test itself does not require one week, but may be called by the OPERATING AUTHORITY any time during the week.

1. The OPERATING AUTHORITY shall confirm the dates of the test with the IOS SUPPLIER.

2. At a time during the one-week test window, selected by the OPERATING AUTHORITY, and not previously disclosed to the IOS RESOURCE:

   2.1. The IOS RESOURCE, including all auxiliary loads, will be isolated from the power system;

   2.2. Within the agreed upon time of being directed to do so by the OPERATING AUTHORITY, the IOS RESOURCE will start without assistance from the system; and

   2.3. The IOS RESOURCE must remain stable (both frequency and voltage) while supplying only its own auxiliary loads or loads in the immediate area for at least 30 minutes.
Line Energizing Test – The ability of the IOS RESOURCE to energize transmission will be tested when conditions permit (during transmission maintenance, for example) but at least once every three years. Tests will be conducted at a time mutually agreed upon by the IOS SUPPLIER and the OPERATING AUTHORITY. If an actual Line Energizing Test is impractical or presents a condition that may pose an undesired risk of load service interruption, these tests may be conducted by steady state and dynamic computer simulation. It should be noted, however, that impediments to system restoration may occur that are not fully modeled in simulations.

1. Sufficient transmission will be de-energized such that when it is picked up by the IOS RESOURCE it demonstrates the IOS RESOURCE’S ability to energize enough transmission to deliver required output to the generator or load that the restoration plan calls for this IOS RESOURCE to supply. The OPERATING AUTHORITY shall be responsible for transmission connections and operations that are compatible with the capabilities of the IOS RESOURCE.

2. Conduct a Basic Starting Test.

3. The CONTROL AREA will direct the IOS RESOURCE to energize the previously de-energized transmission, while monitoring frequency and voltages at both ends of the line. Alternatively, if the OPERATING AUTHORITY agrees, the transmission line can be connected to the IOS RESOURCE before starting, allowing the resource to energize the line as it comes up to speed. This avoids the energizing surge.

4. The IOS RESOURCE must remain stable (both frequency and voltage) while supplying only its own auxiliary loads or external loads and controlling voltage at the remote end of the transmission line for at least 30 minutes.

Load Carrying Test – The ability of the IOS RESOURCE to remain stable and to control voltage and frequency while supplying restoration power to the generator or load that the restoration plan calls for this IOS RESOURCE to supply shall be tested as conditions permit, but at least once every six years. If an actual Load Carrying Test is impractical or presents a condition that may pose an undesired risk of load service interruption, these tests may be conducted by steady state and dynamic computer simulation. It should be noted, however, that impediments to system restoration may occur that are not fully modeled in simulations.

1. Conduct a Basic Starting Test.

2. Conduct a Line Energizing Test.

3. The OPERATING AUTHORITY will direct picking up sufficient load at the remote end of the isolated transmission system to demonstrate the IOS RESOURCE’S capability to supply the required load identified in the restoration plan, while maintaining voltage and frequency for at least 30 minutes.
Interchange Reference Document

Reference Document Subsections
A. The Relationship between Interchange Transactions and Interchange Schedules
B. Interchange Schedules within a Multi-Party Regional Agreement or Transmission Tariff
C. Implementing Interchange Schedules

A. The Relationship between Interchange Transactions and Interchange Schedules

Policy 3.A explains the process for arranging and implementing INTERCHANGE TRANSACTIONS. Policy 3.B explains the procedures for assessing and confirming INTERCHANGE TRANSACTIONS and implementing INTERCHANGE SCHEDULES. The flowchart on the right explains the process by which INTERCHANGE TRANSACTIONS become INTERCHANGE SCHEDULES. Some of these functions are handled by the tagging system used in the INTERCONNECTION. Refer to the “E-tag Reference Document” and the “ERCOT Tagging Reference Document” for further details.

PURCHASING-SELLING ENTITIES “arrange” INTERCHANGE TRANSACTIONS – that is, they buy or sell energy and capacity and record the transaction by forwarding the required data via an INTERCHANGE TRANSACTION “tag” to the appropriate CONTROL AREA(S).

CONTROL AREAS assess and “approve” or “deny” INTERCHANGE TRANSACTIONS based on reliability criteria and arrangements for INTERCONNECTED OPERATIONS SERVICES and transmission rights. Transmission Providers assess the impact of providing the requested transmission service when the service is approved. To “implement” the INTERCHANGE TRANSACTION, all affected CONTROL AREAS 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 CONTROL AREAS A, B, C, and D. (Refer to Figure 1 on the right and table below. For simplicity, we are ignoring losses.)

Interchange Transaction 1 (IT1)
CONTROL AREA A is the SOURCE CONTROL AREA for INTERCHANGE TRANSACTION 1 (IT1) and CONTROL AREA B is the SINK CONTROL AREA. To make IT1 occur, CONTROL AREA A implements an INTERCHANGE SCHEDULE with CONTROL AREA B (S_{AB-IT1}). In this case, the SOURCE CONTROL AREA A is the SENDING CONTROL AREA, and the SINK CONTROL AREA B is the RECEIVING CONTROL AREA.

Interchange Transaction 2 (IT2)
CONTROL AREA A is also the SOURCE CONTROL AREA for INTERCHANGE TRANSACTION 2 (IT2). CONTROL AREA D is the SINK CONTROL AREA for this INTERCHANGE TRANSACTION. B and C are INTERMEDIATE CONTROL AREAS. The resulting INTERCHANGE SCHEDULES are from SENDING CONTROL AREA A to RECEIVING CONTROL AREA B (S_{AB-IT2}), SENDING CONTROL AREA B to RECEIVING CONTROL AREA C (S_{BC-IT2}), and SENDING CONTROL AREA C to RECEIVING CONTROL AREA D (S_{CD-IT2}).
Interchange Transaction 3 (IT3)
CONTROL AREA C is the SOURCE CONTROL AREA for INTERCHANGE TRANSACTION 3 (IT3) and
CONTROL AREA A is the SINK CONTROL AREA. B is the INTERMEDIARY CONTROL AREA. To make IT3
occur, SENDING CONTROL AREA C implements an INTERCHANGE SCHEDULE with RECEIVING CONTROL
AREA B (S\textsubscript{CB-IT3}) and SENDING CONTROL AREA B to RECEIVING CONTROL AREA A (S\textsubscript{BA-IT3}).

Net Schedules
CONTROL AREAS A and B can calculate a NET INTERCHANGE SCHEDULE between these two CONTROL
AREAS by adding S\textsubscript{AB-IT1} and S\textsubscript{AB-IT2} and S\textsubscript{BA-IT3}. Control Areas B and C can calculate a NET INTERCHANGE SCHEDULE between these two CONTROL AREAS by adding S\textsubscript{BC-IT2} and S\textsubscript{CB-IT3}.
The NET SCHEDULED INTERCHANGE for A is S\textsubscript{AB-IT1} + S\textsubscript{AB-IT2} + S\textsubscript{BA-IT3}. The NET SCHEDULED INTERCHANGE for B is S\textsubscript{AB-IT1} + S\textsubscript{AB-IT2} + S\textsubscript{BA-IT3} + S\textsubscript{BC-IT2} + S\textsubscript{CB-IT3}.

Relationship Between Control Areas, Interchange Schedules, and Interchange Transactions

<table>
<thead>
<tr>
<th>Control Area</th>
<th>Sink Control Area for:</th>
<th>Source Control Area for:</th>
<th>Sending Control Area for:</th>
<th>Receiving Control Area for:</th>
<th>Net Interchange Schedules</th>
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<tr>
<td>A</td>
<td>IT3</td>
<td>IT1, IT2</td>
<td>IT1, IT2</td>
<td>IT3</td>
<td>S\textsubscript{AB-IT1} + S\textsubscript{AB-IT2} + S\textsubscript{BA-IT3}</td>
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<td>B</td>
<td>IT1</td>
<td>IT2, IT3</td>
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<td>S\textsubscript{AB-IT1} + S\textsubscript{AB-IT2} + S\textsubscript{BA-IT3}</td>
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<tr>
<td>C</td>
<td>IT3</td>
<td>IT2, IT3</td>
<td>IT2</td>
<td></td>
<td>S\textsubscript{BC-IT2} + S\textsubscript{CB-IT3}</td>
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<tr>
<td>D</td>
<td>IT2</td>
<td></td>
<td>IT2</td>
<td></td>
<td>S\textsubscript{CD-IT2}</td>
</tr>
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</table>

Match
B. Interchange Schedules within a Multi-Party Regional Agreement or Transmission Tariff

If CONTROL AREAS A, B, C, and D are parties to a transmission agreement or tariff, such as a Regional agreement or ISO, then there is no need for the INTERCHANGE SCHEDULES from B to C or C to D as in the previous example. In this case, all four CONTROL AREAS are considered ADJACENT CONTROL AREAS and can schedule directly with each other. (See Figure 2 on the right).

Interchange Transaction 1

CONTROL AREA A is the SOURCE CONTROL AREA for INTERCHANGE TRANSACTION 1 (IT1) and CONTROL AREA B is the SINK CONTROL AREA. To make IT1 occur, CONTROL AREA A implements an INTERCHANGE SCHEDULE with CONTROL AREA B (S\text{AB-IT1}). In this case, the SOURCE CONTROL AREA A is the SENDING CONTROL AREA, and the SINK CONTROL AREA B is the RECEIVING CONTROL AREA and these two control areas are adjacent to each other.

Interchange Transaction 2

CONTROL AREA A is also the SOURCE CONTROL AREA for INTERCHANGE TRANSACTION 2 (IT2). CONTROL AREA D is the SINK CONTROL AREA for this INTERCHANGE TRANSACTION. The resulting INTERCHANGE SCHEDULE is directly from SOURCE (SENDING) CONTROL AREA A to SINK (RECEIVING) CONTROL AREA D (S\text{AD-IT2}).

Interchange Transaction 3

CONTROL AREA C is the SOURCE (SENDING) CONTROL AREA for INTERCHANGE TRANSACTION 3 (IT3) and CONTROL AREA A is the SINK (RECEIVING) CONTROL AREA. To make IT3 occur, SENDING CONTROL AREA C implements an INTERCHANGE SCHEDULE directly with SINK (RECEIVING) CONTROL AREA A (S\text{CA-IT3}).

Net Schedules

There are only three NET INTERCHANGE SCHEDULES:

S\text{AB} = IT1, S\text{AD} = IT2, and S\text{CA} = IT3

The NET SCHEDULED INTERCHANGE for A is S\text{AB-IT1} + S\text{CA-IT3} + S\text{AD-IT2}. For B is S\text{AB-IT1}. For C is S\text{CA-IT3}, For D is S\text{AD-IT2}.

Relationship between Control Areas, Interchange Schedules, and Interchange Transactions

<table>
<thead>
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<td>S\text{AD-IT2}</td>
</tr>
</tbody>
</table>

Figure 2 - Interchange Schedules within a Multi-Party agreement or tariff
C. Implementing Interchange Schedules

1. **Confirming Interchange Schedules.** Interchange Schedules are confirmed between Adjacent Control Areas. The RECEIVING CONTROL AREAS are responsible for initiating contact with the SENDING CONTROL AREAS; however, it is also permissible for the SENDING CONTROL AREA to initiate contact with the RECEIVING CONTROL AREA.

   Figure 3 on the right shows the confirmation “chain.”

2. **Ramp rates.** When the SENDING CONTROL AREA and RECEIVING CONTROL AREA implement an INTERCHANGE SCHEDULE between each other, they must begin their generation adjustments at the same time using the same ramp rates. A mismatch of these parameters will cause a frequency error in the INTERCONNECTION.

3. **Starting and ending times.** Interchange SCHEDULES usually start and end on the clock hour. However, PURCHASING-SELLING ENTITIES may wish to begin or end an INTERCHANGE TRANSACTION at other times, and the CONTROL AREAS should try to accommodate the resulting off-hour INTERCHANGE SCHEDULES if possible.

4. **Interchange accounting.** All CONTROL AREAS must account for their INTERCHANGE SCHEDULES the same way to enable them to confirm their NET INTERCHANGE SCHEDULES each day with their ADJACENT CONTROL AREAS as required in Policy 1F, “Inadvertent Interchange.” NERC requires “block” INTERCHANGE SCHEDULE accounting, which assumes, for energy accounting purposes, that the beginning and ending ramps have zero duration. 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.

5. **Time zones.** Finally, because INTERCHANGE TRANSACTIONS often cross two or more time zones, NERC requires that all electronic INTERCHANGE SCHEDULE communications be in Central Standard Time throughout the year. (Daylight Saving Time will not be used because 1) it creates 23- and 25-hour days during the transition, 2) the transition itself does not occur uniformly across the time zones, and 3) not all areas observe DST.)
6. Curtailing, Canceling, or Terminating Interchange Transactions

6.1. Curtailing Interchange Transactions

6.1.1. Notifying the Sink Control Area.
When a CONTROL AREA or TRANSMISSION PROVIDER must curtail an INTERCHANGE TRANSACTION, it begins the process by contacting its SECURITY COORDINATOR and the SINK CONTROL AREA. When a SECURITY COORDINATOR curtails an INTERCHANGE TRANSACTION, it contacts all other SECURITY COORDINATORS. Then the SECURITY COORDINATOR of the SINK CONTROL AREA notifies the SINK CONTROL AREA, the SOURCE CONTROL AREA, and the originating PURCHASE-SELLING ENTITY, and any DC Tie Operator on the scheduling path of the curtailment.

6.1.2. Notifying other entities. Once the SINK CONTROL AREA has been notified, it contacts the originating PURCHASE-SELLING ENTITY and SOURCE CONTROL AREA directly, confirms the curtailment and the resulting change in their INTERCHANGE SCHEDULES. The SINK CONTROL AREA then contacts the INTERMEDIARY CONTROL AREAS and TRANSMISSION PROVIDERS on the SCHEDULING PATH as well as the PURCHASING-SELLING ENTITY who submitted the tag (this is accomplished via the requirement that CONTROL AREAS, TRANSMISSION PROVIDERS, and PURCHASE-SELLING ENTITY’S have full-time E-Tag monitoring). Following this notification, if the SOURCE CONTROL AREA and SINK CONTROL AREA are not adjacent, they begin implementing the INTERCHANGE SCHEDULE adjustments with their ADJACENT CONTROL AREAS.

6.2. Canceling or Terminating Interchange Transactions. When a PURCHASING-SELLING ENTITY must cancel an INTERCHANGE TRANSACTION before it begins, or terminates one that is in progress, the PURCHASING-SELLING ENTITY shall contact the SINK CONTROL AREA to which it submitted the INTERCHANGE TRANSACTION tag. The SINK CONTROL AREA shall then directly contact its SECURITY COORDINATOR, all CONTROL AREAS, and TRANSMISSION PROVIDERS on the SCHEDULING PATH. Additional details of INTERCHANGE TRANSACTION curtailment are found in Section 3D, “Interchange Transaction Cancellation and Curtailment,” and Policy 9, “Security Coordinator Procedures.”
Parallel Flow Calculation Procedure
Reference Document
Version 1, Draft 1

[See also Appendix 9C1, “NERC TLR Procedure – Eastern Interconnection,” Section F., “Transaction Contribution Factor”]

Subsections
A. Introduction
B. Basic Principles
C. Calculation Method
D. Calculation Procedure
E. Sample Calculation

A. Introduction

This Reference Document explains how to calculate the contribution of Network Integration Transmission Service and Native Load on a TRANSMISSION CONSTRAINT under TLR Level 5 (5a or 5b).

The provision of Point-to-Point (PTP) transmission service as well as Network Integration (NI) Transmission Service and service to Native Load (NL) results in parallel flows on the transmission network of other TRANSMISSION PROVIDERS. When a transmission facility becomes constrained, NERC Policy 9C, Appendix 9C1, calls for curtailment of INTERCHANGE TRANSACTIONS to allow INTERCHANGE TRANSACTIONS of higher priority to be scheduled (a process called “Reallocation”) or to provide transmission loading relief. An INTERCHANGE TRANSACTION is considered for REALLOCATION or CURTAILMENT if its TRANSFER DISTRIBUTION FACTOR exceeds the TLR CURTAILMENT THRESHOLD, which is typically 5% for MONITORED TRANSMISSION FACILITIES. In compliance with the Pro Forma tariffs filed with FERC by TRANSMISSION PROVIDERS, INTERCHANGE TRANSACTIONS using non-firm Point-to-Point TRANSMISSION SERVICE are curtailed first (TLR Level 3a and 3b), followed by transmission reconfiguration (TLR Level 4), and then the curtailment of INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission Service (TLR Level 5a and 5b). The NERC TLR Procedure requires that the curtailment of Firm Point-to-Point Transmission Service be accompanied by the comparable curtailment of Network Integration Transmission Service and service to Native Load to the degree that these three Transmission Services contribute to the CONSTRAINT.

To ensure the comparable curtailment of these three transmission services as part of TLR Level 5a or 5b, the NERC Parallel Flow Task Force (PFTF) has developed a method that allocates appropriate relief amounts to all firm PTP and NI/NL services in a comparable manner. A methodology, called the Per Generator Method Without Counter Flow, or simply the Per Generator Method, has been devised by the PFTF to calculate the portion of parallel flows on any CONSTRAINED FACILITY due to NI/NL service of each CONTROL AREA (CA). The Per Generator Method has been presented to the Security Coordinator Subcommittee (SCS) and the Market Interface Committee (MIC) and both committees have approved the methodology.

The Interchange Distribution Calculator Working Group (IDCWG) has determined that the IDC tool could not be upgraded by the summer 2000 to automatically calculate the parallel flow contributions from NI/NL service. The SCS then directed the Distribution Factor Task Force (DFTF) to develop an interim procedure to implement the Per Generator Method as an integral part of TLR Level 5 for the summer of Year 2000. A description of this interim procedure is summarized in this reference manual.
B. Basic Principles

The basic principles for curtaining Interchange Transactions using Firm Point-to-Point TRANSMISSION SERVICE curtailment based on NERC Policy 9C, Appendix 9C1, are given below:

1. All firm transmission services, including PTP and NI/NL services, that contribute 5% (the CURTAILMENT THRESHOLD) or more to the flow on any CONSTRAINED FACILITY must be curtailed on a pro rata basis.

2. For Firm PTP transmission services, the 5% is based on TRANSFER DISTRIBUTION FACTORS (TDFs). For NI/NL transmission services, the 5% is based on generator-to-load distribution factors (GLDFs). The GLDF on a specific CONSTRAINED FACILITY for a given generator within a CONTROL AREA is defined as the generator’s contribution to the flow on that flowgate when supplying the load of that CONTROL AREA.

3. The Per Generator Method assigns the amount of CONSTRAINED FACILITY relief that must be achieved by each CONTROL AREA NI/NL service. It does not specify how the reduction will be achieved.

4. The Per Generator Method places an obligation on all CONTROL AREAS in the Eastern Interconnection to achieve the amount of CONSTRAINED FACILITY relief assigned to them.

5. The implementation of the Per Generator Method must be based on transmission and generation information that is readily available.

C. Calculation Method

The calculation method is based on the Generation Shift Factors (GSFs) of an area’s assigned generation and the Load Shift Factors (LSFs) of its native load, relative to the system swing bus. The GSFs are calculated from a single bus location in the base case. The LSFs are defined as a general scaling of the native load within each control area. The Generator to Load Distribution Factor (GLDF) is calculated as the GSF minus the LSF. Using the present NERC CURTAILMENT THRESHOLD of 5%, the reporting method looks for generation assigned to native load for which the Generation to Load Distribution Factor (GLDF) is greater than 5%. In cases where the Flowgate is considered limiting in the To → From direction, the sign of the GLDF is reversed.

Generators are included where the sum of the generator PMAXs for a bus is greater than 20 MW, including off-line units (e.g., three 9MW generators add up to greater than 20 MW on a bus). Smaller generators that do not meet this criterion are not included. In the calculation process, all tested generators are listed as in-service and their MVA base is set to the PMAX value. SDX information is then applied for generator outages and deratings as applicable. This process may adjust the output of generators that are not intended to participate for an area. In such cases, the generation MVA base value should be adjusted (Percent = 0%) so that those units do not participate. All participation adjustments should be justifiable upon inquiry.

The original MVA base from the seasonal IDC case is not used because it is zero for many non-participating generators, such as nuclear units. The unit output in the case (PGEN) is not used because it may be turned on to a default 1 MW in some instances. The PGEN is not considered a good indicator of the unit’s capability. The unit maximum capability (PMAX) is considered a good indicator of the unit ability to contribute.

A set of generation ownership data matches the generators to their Native Load areas. By default, the generator ownership data lists each unit as being 100% contributing to the Native Load calculations of the
control area in which it is contained. There may be situations where the ownership would be less than 100%. Examples include: 1) a merchant generator who has tagged TRANSACTIONS; 2) a generator included multiple times for case modeling situations; or 3) a jointly-owned unit. Jointly-owned units may have multiple ownership listings to account for the multiple assigned areas. The joint ownership should be less than or equal to 100%.

Unit ownership can go beyond CONTROL AREA bus ownership. Units assigned to serve native load do not need to reside in the native load control area. However, units outside the native load control area should not be assigned when it is expected that those units will have tags associated with their transfers. Although the Native Load calculation has the ability to handle these ownership situations, the CONTROL AREAS and SECURITY COORDINATORS must supply the data or the default ownership will apply.

For each generator assigned to a CONTROL AREA'S Native Load, the amount of energy flowing on the CONSTRAINED FACILITY is calculated for the generator-to-Native Load transfer. The reporting is limited to those units that have a GLDF greater than or equal to 5%. The amount of transfer is based on the unit’s maximum capability as listed in the base case (PMAX), and a comparison of Native Load level and the available generation assigned to the CONTROL AREA. The available assigned generation does not include small units that do not meet the 20 MW cutoff. When the available generation exceeds the load level, it is assumed that not all the generation is participating, and therefore, the PMAX values are scaled down by the load to generation ratio. If available, excess generation that is sold is expected to be tagged. If available assigned generation is less than the native load level, it is assumed that the area may be importing, and therefore the affected units are not scaled (scaling=1.00). Imports are assumed to be tagged.

**Summary**

If Available Assigned Generation > Native Load, Then Scale Down Pmax

If Available Assigned Generation < Native Load, Then Do not Scale Down Pmax

The amount of Energy on the Flowgate (EOF) that the native load area is responsible for is given as:

$$EOF_{area} = \sum EOF_{gen \text{ assigned to area}}$$

The Energy on the Flowgate (EOF) for a specific assigned generator with a GLDF > 5% is given as:

$$EOF_{assigned \ gen} = (GLDF)(P_{\text{MAX adjusted for SDX}})(\text{Percent}_{\text{Assigned/100}})(\text{Scaling}_{\text{Area}})$$
D. Calculation Procedure

**SDX data requirements**
The factor calculation process uses available SDX data to update the current IDC seasonal case. Daily SDX data for transmission outages, generation outages and de-ratings, and daily load levels are applied to the calculation process. The SDX case updates are validated against tables to verify they match the seasonal case branch and generator lists. This is done to avoid process errors and to prevent the accidental insertion on new case data.

Transmission outages are applied by increasing the impedance to “9999” for out-of-service branches. The impedance adjustment is considered equivalent to the branch outage method, and it is preferred since it does not create islanding. Open transmission branches can also be placed back in-service based on SDX data.

Generator outages and de-ratings reported in SDX data are also applied to the case. The IDC seasonal case is initially adjusted such that the MVA base for all tested units is set to the PMAX value. By further adjusting the MVA base value, SDX generation data is then applied to the case to outage or de-rate units.

Daily SDX load levels are applied to the case. This information is used to update each control area’s scaling factor. When daily load levels are not available through SDX, the seasonal value will be used as the default. The seasonal value is usually larger than the daily value.

The seasonal case is considered a solvable case. The applied daily SDX data makes the prepared daily case unsolvable. However, for factor calculation, a solved case is not required. Only a valid transmission topology is required.

Phase shifters are modeled as fixed angle. This is judged to be adequate for the present. However, in the relatively near future (when the MECS-IMO PARs are placed in service), ability to handle fixed MW operation will be needed.

**Posting of Contribution Factors**
The factors will be calculated by MAIN on a daily basis. The factors will be calculated some time after 1300 CST (or CDT) and will be posted before 1400 PM CST. This time was chosen because SDX data updates are required daily by 1300. The SDX data will be captured for those transmission and generation listings which cross 1401 CST.

A morning calculation may be performed to show the preliminary daily results. This run may be performed about 0800 CST. Specific midday re-runs may be requested by contacting MAIN. A message will be sent to the NERC DFTF after any new report postings. All reports will have a time stamp indicating when they were created. The reports will be posted on the MAIN web site at [http://www.maininc.org/firmcurt/index.htm](http://www.maininc.org/firmcurt/index.htm). This site is password protected for transmission use only. SECURITY COORDINATORS are expected to be given access to the reports via the SCIS system. Contact MAIN staff if access to the reports is needed. Reports are listed for each reliability flowgate. There is also a summary for each CONTROL AREA. Depending upon browser settings, the page may need to be reloaded/refreshed to view updated reports.
E. Sample Calculation

An example of calculating firm transaction curtailments is provided in this section, assuming that the constrained flowgate is #3006 (Eau Claire-Arpin 345 kV circuit). The GLDFs for this flowgate are presented in Attachment 1. In this example, a total Firm PTP contribution of 708.85 MW is assumed to be given by the IDC.

From Attachment 1, the NI/NL contributions of all CONTROL AREAS that impact the CONSTRAINED FACILITY are listed below:

\[
\begin{align*}
\text{ALTE} & = 27.0 \text{ MW} \\
\text{ALTW} & = 41.1 \text{ MW} \\
\text{NSP} & = 33.1 \text{ MW} \\
\text{WPS} & = 26.2 \text{ MW}
\end{align*}
\]

Total NL & NI contribution = 127.4 MW

Total Firm (PTP & NI/NL) contribution = 127.4 MW + 708.85 MW = 836.25 MW

NL & NI portion of total Firm contribution = 127.4/836.25 = 15.2%

PTP portion of total Firm contribution = 708.85/836.25 = 84.47%

Allocation of relief of the CONSTRAINED FACILITY to each CONTROL AREA with impactive NI/NL contribution is given below:

\[
\begin{align*}
\text{ALTE} & = \frac{27.0}{127.4} \times 0.152 = 3.2\% \\
\text{ALTW} & = \frac{41.1}{127.4} \times 0.152 = 4.9\% \\
\text{NSP} & = \frac{33.1}{127.4} \times 0.152 = 3.9\% \\
\text{WPS} & = \frac{26.2}{127.4} \times 0.152 = 3.1\%
\end{align*}
\]

Assume that 50 MW of relief is needed. Then those CONTROL AREAS that impact NI/NL contribution and Firm PTP service are responsible for the providing the following amounts of flowgate relief:

Relief provided by removing Firm PTP = 0.845 x 50 = 42.25 MW

Relief provided by removing NL & NS contributions ALTE = 0.032 x 50 = 1.60 MW

Relief provided by removing NL & NS contributions ALTW = 0.049 x 50 = 2.45 MW

Relief provided by removing NL & NS contributions NSP = 0.039 x 50 = 1.95 MW

Relief provided by removing NL & NS contributions WPS = 0.031 x 50 = 1.55 MW
### Native Load Responsibilities

**Flowgate #:** 3006  **Flowgate Name:** EAU CLAIRE-ARPIN 345 KV

<table>
<thead>
<tr>
<th>Common Name</th>
<th>Generator Reference System</th>
<th>Generator Shift Factor (GSF)</th>
<th>Percent Assigned</th>
<th>GLDF Gen to Load Factor</th>
<th>Pmax (MW)</th>
<th>Energy on Flowgate</th>
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<tr>
<td>ALTE #364</td>
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<td>0.298</td>
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<td>55.0</td>
<td>5.0</td>
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</tr>
</tbody>
</table>
A. System Data Exchange (SDX) – Eastern Interconnection Only

The SDX is the NERC approved method for the submittal of operational planning horizon data that is required in NERC Policy 9 Subsection A – Next Day Operations Planning Process, Requirement 1. This data is shared throughout the interconnection(s) for use in ATC calculations and the NERC TLR application, the Interchange Distribution Calculator (IDC) and power system studies. The data is required to be submitted hourly for each Control Area and received by the SDX system by 20 minutes prior to the reporting hour. Updates to these data may be submitted more frequently. Additional data submittals are required per the guidelines below. It is the intent of the SDX to provide the most current power system data to the NERC and Reliability power system applications that rely on the data for accurate calculations.

Data Considerations

The information type and format that must be adhered to in an SDX submittal is defined in the NERC SDX Data Specification. It is required that the following criteria also be followed when issuing an SDX data submittal.

1. All generation status changes for generation summing to 20 MW or higher on a bus must be reported for each Control Area.
   1.1. Generation elements must be submitted in the PSSE bus name format and be contained in the most recent IDC application model. The most recent IDC model can be found at the NERC Distribution Factor Working Group (DFWG) website.
   1.2. This data improves the accuracy of the calculations in the IDC and ATC applications with special emphasis given to the Network Integration (NI) transmission service and service to Native Load (NL) responsibility calculation in the IDC.
   1.3. Additional generation data may be submitted at the Reliability Coordinators desire. The SDX format and application will not prohibit the submittal of generation of all levels that is contained in the IDC model.

2. All transmission status changes 100 kV or higher must be reported for each Control Area.
   2.1. Transmission elements must be submitted in the PSSE bus name format of the most recent IDC application model. The most recent model can be found at the NERC Distribution Factor Working Group (DFWG) website.
   2.2. This requirement improves the accuracy of the calculations in the IDC and ATC applications.
   2.3. Additional transmission data may be submitted at the Reliability Coordinators desire. The SDX format and application will not prohibit the submittal of transmission of all kV levels that is contained in the IDC model.
3. **The “Daily”, “Hourly”, “Weekly” and “Monthly” loads along with the “Generation” and “Transmission” status changes must be updated as a minimum for each Control Area, as indicated below.**

3.1. The “Daily” table, which will be updated daily, will contain seven days of daily peak data beginning with current day. The peak hour of the day will also be specified. This data is required by all Reliability Coordinators to promote coordination in the interconnection.

3.2. The data for the “Hourly” table, which will be updated hourly, will be provided for each hour from current hour until midnight tomorrow (i.e. 25-48 hours). But the hourly data set can contain more than 25-48 hours if the RC so desires.

3.3. The “Weekly” table, which will be updated weekly, will contain four weeks of peak data beginning with the current week. The data should be submitted using the Monday of each week as the weekly identifier.

3.4. The “Monthly” table, which will be updated monthly, will contain 12 months of peak data beginning with the current month. The data should be submitted using day one of the month as the monthly identifier.

3.5. Generation and Transmission status changes, as indicated in the preceding sections, will be updated hourly.

This requirement improves the accuracy of the calculations in the IDC and ATC applications and reliability studies in the interconnection.

4. **The Phase Shifter Tap Setting section of the file will be used to allow those entities with phase shifters to communicate the current tap settings. This information will be used by the NERC IDC to more accurately model phase shifters and their impact on the power system.**

4.1. This section is optional to those entities that do not have phase shifter devices and/or are not utilizing the IDC PAR modeling capability.

4.2. Tap positions should be communicated in or as close to real time as possible. An effective method would be a direct connection through the ICCP, ISN to the SDX and/or IDC application.

5. **The Three Winding Transformer section of the file is used to communicate SDX information for three winding transformers. Due to the industry modeling of these devices it is necessary to use this section to communicate the transformer data rather than using the transmission section of the file.**

5.1. If the transformer is modeled using the three winding transformer capability of PSSE Version 28 or higher this section must be used to communicate the needed SDX information about them.

6. **The Element Group section of the file is used to communicate SDX information about multiple power system elements using one name or identifier.**

6.1. The element groups must be set up in the NERC SDX application database prior to using this section of the file. The SDX application will recognize the element group and communicate the appropriate element information to the NERC IDC.
6.2. Element groups are typically used to help the SDX user outage several power system elements at one time (i.e. Bus outages, transformer/generation combinations etc.)

6.3. Refer to the NERC SDX application at [http://sdx.mcg.nerc.com](http://sdx.mcg.nerc.com) for element group set up.

7. The SDX uses several status codes to represent the state of a power system element. These status codes are inserted into the SDX data file in the “Status” field for each power system element section. If the “Status” field does not contain one of the following status codes it will create an error for the entry.

7.1. Each SDX user is Required to select one of the four following status indicators for each power system SDX entry:

Note: A SDX element will automatically be placed back to the base case status when the element entry is removed from the file submittal or the entry expires.

7.1.1. “O” – Out Of Service for the time stated

- The NERC IDC application will take the element out of service for the time stated.

7.1.2. “I” – In-Service for the time stated

- The NERC IDC application will place the element in service for the time stated.
- It is not necessary to use this status each time an element is put back in service from an outage state. The status is meant to indicate a change in normal status for an element (i.e. normally offline transmission and/or generation that is put in service for a specified time).

7.1.3. “P” – Partially Limited and Derated to a level less than its maximum.

- The NERC IDC Application will not recognize Partially Limited units for its calculations.
- This data is very crucial to other Power System studies and the MW entry should indicate the available MW output of the unit.

7.1.4. “F” – Forced Out of Service for the time stated

- This will cause the NERC IDC to take the element out of service for calculations.
- When this status is selected the outage is also communicated and posted to the NERC RCIS based on the following criteria:
  a. Transmission elements 230 kV and above
  b. Generators 300 MW capacity and above
  c. These forced outages will be posted to the RCIS within one hour of the status change.
Reliability Coordinator Reference Document

A. System Data Exchange (SDX) – Eastern Interconnection Only

7.2. The following additional status indications are available for the SDX user to further clarify the type of SDX entry that is being submitted. These status indicators are recommended to be used when appropriate in place of the required statuses above.

7.2.1. “SS” – Offline but can be brought on-line in 3 or more hours-Standby Slow

- This will cause the NERC IDC application to take the element out of service for calculations.

7.2.2. “SF” – Offline but can be brought on-line in one to three hours – Standby Fast

- This will cause the NERC IDC application to take the element out of service for calculations.

7.2.3. “PS” – The Element is Pumping and is acting like a load rather than a generator for the time stated

- This will cause no action in the NERC IDC until a later date and can be used by SDX users for other power system studies.

7.2.4. “SVC” – The element is out of service for the time stated and is a Static Var Compensator

- This will cause the NERC IDC application to take the generator out of service for calculations.

7.2.5. “HT” – Hot Line work-Indicates that there is work that is taking place on the element while it is in-service

- This will have no action taken by the NERC IDC application for their calculations

8. Direct entry of outages into the IDC application will no longer be supported with the exception of NNL generation status during a TLR Level 5 event. There is a link provided to the NERC SDX system to accommodate outage entry.

9. The most recent version of the NERC SDX Data Specification to be complied with.

9.1. The most recent version of the data specification can be found at the NERC SDX website [http://www.nerc.com/~filez/sdx.html](http://www.nerc.com/~filez/sdx.html)

This requirement ensures that all applications depending on this data will be able to recognize the format it is submitted in for use in their reliability calculations.

**Transferring the SDX File**

In order to ensure all Control Areas and Reliability Coordinators have a means to submit the required SDX data, NERC will provide a tool that will adhere to the most recent SDX data specification for submittal. This is a web-based tool that requires a NERC assigned username and password and is only available to signatures of the NERC Data Confidentiality Agreement. Along with the FTP of the Comma Separated File the HTTP and XML data submittals will be accommodated through the use of defined templates. Information on the most recent NERC SDX tool will be available on the NERC website at [http://www.nerc.com/~filez/sdx.html](http://www.nerc.com/~filez/sdx.html).
Information and guidelines on transferring the SDX file will also be provided at the NERC SDX site for entities that wish to submit the SDX file via another means.

*By exception some entities may have to work through alternative means to exchange data. This must be agreeable to all parties involved.*


**B. TLR Level 6 Declarations**

Per NERC Appendix 9C1 “Transmission Load Relief Procedures – Eastern Interconnection” it states that if a Reliability Coordinator is unable to mitigate the constraint on an interface using TLR Levels 3, 4, or 5 the Reliability Coordinator has the authority to immediately direct a Control Area to take actions to reduce load to mitigate the critical condition until transactions can be reduced using the TLR method or the system can be returned to a reliable state. This is considered a TLR Level 6 – Emergency Procedures.

In order for all Reliability Coordinators to understand how the Interchange Distribution Calculator (IDC) handles the issuance of a TLR Level 6 this document will describe the functionality that currently exists and options that the Reliability Coordinator has when declaring this critical TLR Level. This will help ensure the correct action is taken for the given event.

**IDC Treatment of TLR Level 6**

When a RC issues a TLR Level 6 on a flowgate (FG) in the IDC the application will search the Non-Firm and Firm E-Tags that are in the IDC database for those that affect the FG greater than or equal to 5%. It will create two sets of E-Tags from this list for the Reliability Coordinator to curtail:

1. If the E-Tag has an active MW amount in the current hour it will be curtailed to zero MW.

2. If the E-Tag is planned to start the Next Hour it will not be allowed to start and will be curtailed to zero for the Next hour

Once this report is created and displayed as the Congestion Management Report the Reliability Coordinator will then have three options to move forward with the TLR Level 6:

1. **Confirm the curtailment list that contains the Non-Firm and Firm complete curtailments for the Current and Next hour.**
   
   1.1. This will alert the other Reliability Coordinators that a TLR Level 6 has been declared and that there are curtailments that need to be acknowledged for implementation.
   
   1.2. Once the Sinking Reliability Coordinators Acknowledge the curtailments the IDC will send a Reliability Cap of Zero to the Control Area entities on the E-Tags for Curtailment implementation.

2. **Exclude some or all of the E-Tag curtailments from the Congestion Management Report before declaring a TLR Level 6.**

   2.1. This can be done by the Issuing Reliability Coordinator using the “Re-issue/Exclude” option in the Congestion Management Report.

   2.2. This will give the Issuing Reliability Coordinator the option of selecting those transactions they wish to exclude from the TLR issuance.

   2.3. Once the appropriate E-Tags are selected the Reliability Coordinator will re-issue the TLR and the list of Excluded E-Tags will appear on the CMR but will not be in the curtailed state. The Reliability Coordinator will then have to confirm the TLR to send the TLR Level 6 notification to the other Reliability Coordinators.

   2.4. Any tags that were NOT chosen for Exclusion will be sent out to the other Reliability Coordinators for Acknowledgement and curtailment.
2.5. This option allows the Reliability Coordinator to declare a TLR Level 6 without implementing E-Tag curtailments.

3. **Disregard some or all of the E-Tag curtailments from the Congestion Management Report while acknowledging the curtailments of a TLR Level 6.**

3.1. The Sinking Reliability Coordinator can only do this for each E-Tag Curtailment after they receive a TLR Level 6 Congestion Management Report from the Issuing Reliability Coordinator.

3.2. The Sinking Reliability Coordinator will select the “Disregard” option for the tags they wish not to curtail. This is done in the Acknowledgement screen.

3.3. When the “Disregard” option is chosen and the “Acknowledgement” button selected the IDC will update the Congestion management report to identify to all Reliability Coordinator that the Sinking Reliability Coordinator has disregarded the curtailment and does not plan on implementing it.

3.4. This will prompt the Issuing Reliability Coordinator to initiate a conversation with the Sinking Reliability Coordinator for further clarification on why the suggested curtailment will not take place.
Available Transfer Capability Definitions and Determination

A framework for determining available transfer capabilities of the interconnected transmission networks for a commercially viable electricity market

North American Electric Reliability Council

June 1996
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NERC

Available Transfer Capability Definitions and Determination
EXECUTIVE SUMMARY

This report, *Available Transfer Capability Definitions and Determination*, is in response to a NERC Strategic Initiative to “develop uniform definitions for determining Available (Transmission) Transfer Capability (ATC) and related terms that satisfy both [Federal Energy Regulatory Commission] FERC and electric industry needs, and which are to be implemented throughout the industry.” The NERC Board of Trustees at its May 13–14, 1996 meeting approved this report and endorsed its use by all segments of the electric industry.

The report establishes a framework for determining ATCs of the interconnected transmission networks for a commercially viable wholesale electricity market. The report also defines the ATC Principles under which ATC values are to be calculated. It is non-prescriptive in that it permits individual systems, power pools, subregions, and Regions to develop their own procedures for determining or coordinating ATCs based on a regional or wide-area approach in accordance with the Principles defined herein. The proposed ATC calculation framework is based on the physical and electrical characteristics and capabilities of the interconnected networks as applicable under NERC, Regional, subregional, power pool, and individual system reliability planning and operating policies, criteria, or guides.

This report provides an initial framework on ATC that will likely be expanded and modified as experience is gained in its use and as more is learned about how the competitive electric power market will function. The U.S. Federal Energy Regulatory Commission’s final rules, Orders No. 888 and No. 889 pertaining to promoting wholesale competition through open access non-discriminatory transmission services by public utilities and an open access same-time information system, respectively, were issued April 24, 1996. The framework for the determination of ATC as outlined in this report is in accord with the key provisions of these rulemakings.

ATC PRINCIPLES

The following Available Transfer Capability (ATC) Principles govern the development of the definition and determination of ATC and related terms. All transmission provider and user entities are expected to abide by these Principles.

1. ATC calculations must produce commercially viable results. ATCs produced by the calculations must give a reasonable and dependable indication of transfer capabilities available to the electric power market.

2. ATC calculations must recognize time-variant power flow conditions on the entire interconnected transmission network. In addition, the effects of simultaneous transfers and parallel path flows throughout the network must be addressed from a reliability viewpoint.

3. ATC calculations must recognize the dependency of ATC on the points of electric power injection, the directions of transfers across the interconnected transmission network, and the points of power extraction. All entities must provide sufficient information necessary for the calculation of ATC.

4. Regional or wide-area coordination is necessary to develop and post information that reasonably reflects the ATCs of the interconnected transmission network.
5. ATC calculations must conform to NERC, Regional, subregional, power pool, and individual system reliability planning and operating policies, criteria, or guides.

6. The determination of ATC must accommodate reasonable uncertainties in system conditions and provide operating flexibility to ensure the secure operation of the interconnected network.

The calculation of transfer capability is generally based on computer simulations of the operation of the interconnected transmission network under a specific set of assumed operating conditions. These simulations are typically performed “off line,” well before the systems approach that operational state. Each simulation represents a single “snapshot” of the operation of the interconnected network based on the projections of many factors. As such, they are viewed as reasonable indicators of network performance and available transfer capability.

**ATC DEFINITIONS**

**Available Transfer Capability (ATC)** is a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. Mathematically, ATC is defined as the Total Transfer Capability (TTC) less the Transmission Reliability Margin (TRM), less the sum of existing transmission commitments (which includes retail customer service) and the Capacity Benefit Margin (CBM).

**Total Transfer Capability (TTC)** is defined as the amount of electric power that can be transferred over the interconnected transmission network in a reliable manner while meeting all of a specific set of defined pre- and post-contingency system conditions.

**Transmission Reliability Margin (TRM)** is defined as that amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.

**Capacity Benefit Margin (CBM)** is defined as that amount of transmission transfer capability reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements.

**Curtailability** is defined as the right of a transmission provider to interrupt all or part of a transmission service due to constraints that reduce the capability of the transmission network to provide that transmission service. Transmission service is to be curtailed only in cases where system reliability is threatened or emergency conditions exist.

**Recallability** is defined as the right of a transmission provider to interrupt all or part of a transmission service for any reason, including economic, that is consistent with FERC policy and the transmission provider’s transmission service tariffs or contract provisions.

**Non-recallable ATC (NATC)** is defined as TTC less TRM, less non-recallable reserved transmission service (including CBM).
EXECUTIVE SUMMARY

Recallable ATC (RATC) is defined as TTC less TRM, less recallable transmission service, less non-recallable transmission service (including CBM). RATC must be considered differently in the planning and operating horizons. In the planning horizon, the only data available are recallable and non-recallable transmission service reservations, whereas in the operating horizon transmission schedules are known.

ATC AND RELATED TERMS

ATC and related terms are depicted graphically below. They form the basis of a transmission service reservation system that will be used to reserve and schedule transmission services in the new, competitive electricity market.
INTRODUCTION

BACKGROUND

Available Transmission Capacity as described in the U.S. Federal Energy Regulatory Commission’s (FERC) March 29, 1995 Notice of Proposed Rulemaking (NOPR), Docket RM95-8-000, Section III-E4f, is a new term that has not been universally defined or used by the electric industry. The electric industry has historically used other standard terms, techniques, and methodologies to define and calculate meaningful measures of the transmission transfer capability of the interconnected transmission networks. These terms, which include First Contingency Total Transfer Capability (FCTTC) and First Contingency Incremental Transfer Capability (FCITC) as defined in NERC’s May 1995 Transmission Transfer Capability reference document, are still applicable measures in an open transmission access environment. FERC’s term Available Transmission Capacity and its definition and relationship to the industry’s terminology need to be further clarified.

In its NOPR, FERC also requires that Available Transmission Capacity information be made available on a publicly accessible Real-time Information Network (RIN). Definitions of Available Transmission Capacity in the report of the industry’s Electronic Information Network “What” Working Group, which was filed with FERC on October 16, 1995, are only considered to be assumptions to support the Working Group’s effort in determining what information should be included on RINs. This report further refines those definitions.

It must be noted early in this report that electric systems in Canada and the northern portion of Baja California, Mexico, which are electrically interconnected with electric systems in the United States, are active members in NERC and the Regional Councils and are committed to promoting and maintaining interconnected electric system reliability. These non-U.S. systems are not, however, subject to FERC jurisdiction, and the commercial aspects of the definitions contained herein are not necessarily applicable to the operation of their internal transmission systems.

TERMINOLOGY CONVENTION

FERC used the term Available Transmission Capacity in its NOPR to label the information that is to be made accessible to all transmission users as an indication of the available capability of the interconnected transmission networks to support additional transmission service. To avoid confusion with individual transmission line capacities or ratings, all references to “ATC” throughout this report will refer to Available (Transmission) Transfer Capability and its related terms as defined in this report.

NERC STRATEGIC INITIATIVE

One of several Strategic Initiatives for NERC, approved by the NERC Board of Trustees on October 3, 1995, is to “develop uniform definitions for determining Available (Transmission) Transfer Capability and related terms that satisfy both FERC and electric industry needs, and which are to be implemented throughout the industry.” The then existing NERC Transmission Transfer Capability Task Force, with expanded membership to include all segments of the electric industry, was assigned this responsibility for completion in May 1996.
INTRODUCTION

PURPOSE OF THIS REPORT

This report is the response to NERC’s Strategic Initiative on ATC and defines ATC and related terms. From a commercial perspective, the key element in the development of uniform definitions for transmission transfer capability is the amount of transfer capability that is available at a given time for purchase or sale in the electric power market under various system conditions. Open access to the transmission systems places a new emphasis on the use of the interconnected networks. As such, future electric power transfers are anticipated to increase over a wide range of system conditions, making the reliable operation of the transmission networks more complex. To effectively maintain system reliability, those who calculate, report, post, and use this information must all have the same understanding of its meaning for commercial use. To accomplish this purpose, this report will answer the following questions:

- What is ATC?
- How does ATC relate to industry standard terminology?
- What physical factors need to be considered in determining ATC?
- What reliability issues must be considered in determining ATC?
- How is ATC calculated?
- How will ATC be commercially used?

The report establishes a framework for determining the ATCs of the interconnected transmission networks for a commercially viable electricity market. Although the report defines the ATC Principles under which ATCs are to be calculated, it is non-prescriptive in that it permits individual systems, power pools, sub-regions, and Regions to develop their own procedures for determining or coordinating ATCs based on a regional or wide-area approach in accordance with these Principles.

The report does not address transmission ownership and equity issues, nor does it address the allocation of transmission services or ATC values. The calculation of ATC is based strictly on the physical and electrical characteristics and capabilities of the interconnected networks as applicable under NERC, Regional, subregional, power pool, and individual system reliability planning and operating policies, criteria, or guides.

As the competitive electric power market develops, more will be learned on how these markets will function and how the definitions of ATC will be used. This report provides an initial framework on ATC, which will likely be expanded and modified as experience is gained in its use. The U.S. Federal Energy Regulatory Commission’s final rules, Orders No. 888 and No. 889 pertaining to promoting wholesale competition through open access non-discriminatory transmission services by public utilities and an open access same-time information system, respectively, were issued April 24, 1996. The framework for the determination of ATC as outlined in this report is in accord with the key provisions of these rulemakings.
Available Transfer Capability Principles

Available Transfer Capability (ATC) is a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. As a measure bridging the technical characteristics of how interconnected transmission networks perform to the commercial requirements associated with transmission service requests, ATC must satisfy certain principles balancing both technical and commercial issues. ATC must accurately reflect the physical realities of the transmission network, while not being so complicated that it unduly constrains commerce. The following principles identify the requirements for the calculation and application of ATCs.

1. **ATC calculations must produce commercially viable results.** ATCs produced by the calculations must give a reasonable and dependable indication of transfer capabilities available to the electric power market. The frequency and detail of individual ATC calculations must be consistent with the level of commercial activity and congestion.

2. **ATC calculations must recognize time-variant power flow conditions on the entire interconnected transmission network.** In addition, the effects of simultaneous transfers and parallel path flows throughout the network must be addressed from a reliability viewpoint. Regardless of the desire for commercial simplification, the laws of physics govern how the transmission network will react to customer demand and generation supply. Electrical demand and supply cannot, in general, be treated independently of one another. All system conditions, uses, and limits must be considered to accurately assess the capabilities of the transmission network.

3. **ATC calculations must recognize the dependency of ATC on the points of electric power injection, the directions of transfers across the interconnected transmission network, and the points of power extraction.** All entities must provide sufficient information necessary for the calculation of ATC. Electric power flows resulting from each power transfer use the entire network and are not governed by the commercial terms of the transfer.

4. **Regional or wide-area coordination is necessary to develop and post information that reasonably reflects the ATCs of the interconnected transmission network.** ATC calculations must use a regional or wide-area approach to capture the interactions of electric power flows among individual, subregional, Regional, and multiregional systems.

5. **ATC calculations must conform to NERC, Regional, subregional, power pool, and individual system reliability planning and operating policies, criteria, or guides.** Appropriate system contingencies must be considered.

6. **The determination of ATC must accommodate reasonable uncertainties in system conditions and provide operating flexibility to ensure the secure operation of the interconnected network.** A Transmission Reliability Margin (TRM) may be necessary to apply this Principle. Additionally, transmission capability (defined as Capacity Benefit Margin or CBM) may need to be reserved to meet generation reliability requirements.
The key basic concepts of transmission transfer capability are described below. Numerous other terms related to transfer capability are explored in detail in NERC’s May 1995 Transmission Transfer Capability reference document. The concepts and terms in that document are still applicable in an open transmission environment.

**Transfer Capability**

Transfer capability is the measure of the ability of interconnected electric systems to reliably move or transfer power from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). In this context, “area” may be an individual electric system, power pool, control area, subregion, or NERC Region, or a portion of any of these. Transfer capability is also directional in nature. That is, the transfer capability from Area A to Area B is not generally equal to the transfer capability from Area B to Area A.

**Transfer Capability versus Transmission Capacity**

Electric systems throughout NERC have agreed to use common terminology to calculate and report transmission transfer limits to maintain the reliability of the interconnected transmission networks. These transfer values are called “capabilities” (differentiating them from “capacities”) because they are highly dependent on the generation, customer demand, and transmission system conditions assumed during the time period analyzed. The electric industry generally uses the term “capacity” as a specific limit or rating of power system equipment. In transmission, capacity usually refers to the thermal limit or rating of a particular transmission element or component. The ability of a single transmission line to transfer electric power, when operated as part of the interconnected network, is a function of the physical relationship of that line to the other elements of the transmission network.

Individual transmission line capacities or ratings cannot be added to determine the transfer capability of a transmission path or interface (transmission circuits between two or more areas within an electric system or between two or more systems). Such aggregated capacity values may be vastly different from the transmission transfer capability of the network. Often, the aggregated capacity of the individual circuits of a specific transmission interface between two areas of the network is greater than the actual transfer capability of that interface. In summary, the aggregated transmission line capacities of a path or interface do not represent the transfer capabilities between two areas.

**Determination of Transfer Capability**

The calculation of transfer capability is generally based on computer simulations of the operation of the interconnected transmission network under a specific set of assumed operating conditions. These simulations are typically performed “off line,” well before the systems approach that operational state. Each simulation represents a single “snapshot” of the operation of the interconnected network based on the projections of many factors. As such, they are viewed as reasonable indicators of network performance and available transfer capability. Among the factors considered in these simulations are:
TRANSMISSION TRANSFER CAPABILITY CONCEPTS

- Projected Customer Demands — Base case demand levels should be appropriate to the system conditions and customer demand levels under study and may be representative of peak, off-peak or shoulder, or light demand conditions.

- Generation Dispatch — Utility and nonutility generators should be realistically dispatched for the system conditions being simulated.

- System Configuration — The base case configuration of the interconnected systems should be representative of the conditions being simulated, including any generation and transmission outages that are expected. The activation of any operating procedures normally expected to be in effect should also be included in the simulations.

- Base Scheduled Transfers — The scheduled electric power transfers that should be modeled are those that are generally considered to be representative of the base system conditions being analyzed and which are agreed upon by the parties involved.

- System Contingencies — A significant number of generation and transmission system contingencies should be screened, consistent with individual electric system, power pool, subregional, and Regional planning criteria or guides, to ensure that the facility outage most restrictive to the transfer being studied is identified and analyzed. The contingencies evaluated may in some instances include multiple contingencies where deemed to be appropriate.

The conditions on the interconnected network continuously vary in real time. Therefore, the transfer capability of the network will also vary from one instant to the next. For this reason, transfer capability calculations may need to be updated periodically for application in the operation of the network. In addition, depending on actual network conditions, transfer capabilities can often be higher or lower than those determined in the off-line studies. The farther into the future that simulations are projected, the greater is the uncertainty in assumed conditions. However, transfer capabilities determined from simulation studies are generally viewed as reasonable indicators of actual network capability.

LIMITS TO TRANSFER CAPABILITY

The ability of interconnected transmission networks to reliably transfer electric power may be limited by the physical and electrical characteristics of the systems including any one or more of the following:

- Thermal Limits — Thermal limits establish the maximum amount of electrical current that a transmission line or electrical facility can conduct over a specified time period before it sustains permanent damage by overheating or before it violates public safety requirements.

- Voltage Limits — System voltages and changes in voltages must be maintained within the range of acceptable minimum and maximum limits. For example, minimum voltage limits can establish the maximum amount of electric power that can be transferred without causing damage to the electric system or customer facilities. A widespread collapse of system voltage can result in a blackout of portions or all of the interconnected network.
TRANSMISSION TRANSFER CAPABILITY CONCEPTS

Stability Limits — The transmission network must be capable of surviving disturbances through the transient and dynamic time periods (from milliseconds to several minutes, respectively) following the disturbance. All generators connected to ac interconnected transmission systems operate in synchronism with each other at the same frequency (nominally 60 Hertz). Immediately following a system disturbance, generators begin to oscillate relative to each other, causing fluctuations in system frequency, line loadings, and system voltages. For the system to be stable, the oscillations must diminish as the electric systems attain a new, stable operating point. If a new, stable operating point is not quickly established, the generators will likely lose synchronism with one another, and all or a portion of the interconnected electric systems may become unstable. The results of generator instability may damage equipment and cause uncontrolled, widespread interruption of electric supply to customers.

The limiting condition on some portions of the transmission network can shift among thermal, voltage, and stability limits as the network operating conditions change over time. Such variations further complicate the determination of transfer capability limits.

USES OF TRANSMISSION SYSTEMS

The interconnected transmission networks tie together major electric system facilities, generation resources, and customer demand centers. They are planned, designed, and constructed to operate reliably within thermal, voltage, and stability limits for the following purposes:

€ To Deliver Electric Power to Customers — Transmission networks must provide for the reliable transfer of the electric power output from generation resources to customers under a wide variety of operating conditions.

€ To Provide Flexibility for Changing System Conditions — Transmission capability must be available on the interconnected network to provide flexibility to reliably handle the shift in transmission facility loadings caused by maintenance and forced outages of generation and transmission equipment, and a wide range of variable system conditions, such as higher than expected customer demands, or construction delays of new facilities.

€ To Reduce the Need for Installed Generating Capacity — Transmission interconnections between neighboring systems provide for the sharing of installed generating capacity, taking advantage of the diversity in customer demands and generation availability over a wide area, thereby reducing the amount of installed generating capacity necessary to meet generation reliability requirements in each of the interconnecting systems.

€ To Allow Economic Exchange of Electric Power Among Systems — Transmission interconnections between systems, coupled with internal system transmission facilities, allow for the economic exchange of electric power among neighboring systems. Such economy transfers help reduce the overall cost of electricity to customers.
DEFINITION OF TOTAL TRANSFER CAPABILITY

The Total Transfer Capability (TTC) between any two areas or across particular paths or interfaces is direction specific and consistent with the First Contingency Total Transfer Capability (FCTTC) as defined in NERC’s May 1995 Transmission Transfer Capability reference document.

TTC is the amount of electric power that can be transferred over the interconnected transmission network in a reliable manner based on all of the following conditions:

1. For the existing or planned system configuration, and with normal (pre-contingency) operating procedures in effect, all facility loadings are within normal ratings and all voltages are within normal limits.

2. The electric systems are capable of absorbing the dynamic power swings, and remaining stable, following a disturbance that results in the loss of any single electric system element, such as a transmission line, transformer, or generating unit.

3. After the dynamic power swings subside following a disturbance that results in the loss of any single electric system element as described in 2 above, and after the operation of any automatic operating systems, but before any post-contingency operator-initiated system adjustments are implemented, all transmission facility loadings are within emergency ratings and all voltages are within emergency limits.

4. With reference to condition 1 above, in the case where pre-contingency facility loadings reach normal thermal ratings at a transfer level below that at which any first contingency transfer limits are reached, the transfer capability is defined as that transfer level at which such normal ratings are reached.

5. In some cases, individual system, power pool, subregional, or Regional planning criteria or guides may require consideration of specified multiple contingencies, such as the outage of transmission circuits using common towers or rights-of-way, in the determination of transfer capability limits. If the resulting transfer limits for these multiple contingencies are more restrictive than the single contingency considerations described above, the more restrictive reliability criteria or guides must be observed.

DETERMINATION OF TOTAL TRANSFER CAPABILITY

The concepts for determining transfer capability described in NERC’s Transmission Transfer Capability reference document are still valid and do not change with the advent of open transmission access or the need to determine ATCs. The major points contained therein are briefly outlined below.

System Conditions
Base system conditions are identified and modeled for the period being analyzed, including projected customer demands, generation dispatch, system configuration, and base scheduled transfers. As system conditions change, the base system conditions under which TTC is calculated may also need to be modified.
**TTC Definition and Determination**

**Critical Contingencies**
During transfer capability studies, many generation and transmission system contingencies throughout the network are evaluated to determine which facility outages are most restrictive to the transfer being analyzed. The types of contingencies evaluated are consistent with individual system, power pool, subregional, and Regional planning criteria or guides. The evaluation process should include a variety of system operating conditions because as those conditions vary, the most critical system contingencies and their resulting limiting system elements could also vary.

**System Limits**
As discussed earlier, the transfer capability of the transmission network may be limited by the physical and electrical characteristics of the systems including thermal, voltage, and stability considerations. Once the critical contingencies are identified, their impact on the network must be evaluated to determine the most restrictive of those limitations. Therefore, the TTC becomes:

\[
\text{TTC} = \text{Minimum of \{Thermal Limit, Voltage Limit, Stability Limit\}}
\]

As system operating conditions vary, the most restrictive limit on TTC may move from one facility or system limit to another as illustrated in Figure 1.

![Figure 1: Limits to Total Transfer Capability](image-url)
Parallel Path Flows
When electric power is transferred across the network, parallel path flows occur. This complex electric transmission network phenomenon can affect all systems of an interconnected network, especially those systems electrically near the transacting systems. As a result, transfer capability determinations must be sufficient in scope to ensure that limits throughout the interconnected network are addressed. In some cases, the parallel path flows may result in transmission limitations in systems other than the transacting systems, which can limit the transfer capability between the two contracting areas.

Non-Simultaneous and Simultaneous Transfers
Transfer capability can be determined by simulating transfers from one area to another independently and non-concurrently with other area transfers. These capabilities are referred to as “non-simultaneous” transfers. Another type of transfer capability reflects simultaneous or multiple transfers concurrently. These capabilities are developed in a manner similar to that used for non-simultaneous capability, except that the interdependency of transfers among the other areas is taken into account. These interdependent capabilities are referred to as “simultaneous” transfers. No simple relationship exists between non-simultaneous and simultaneous transfer capabilities. The simultaneous transfer capability may be lower than the sum of the individual non-simultaneous transfer capabilities.
Two types of transmission transfer capability margins include:

€ Transmission Reliability Margin (TRM) — to ensure the secure operation of the interconnected transmission network to accommodate uncertainties in system conditions.
€ Capacity Benefit Margin (CBM) — to ensure access to generation from interconnected systems to meet generation reliability requirements.

Individual systems, power pools, subregions, and Regions should identify their TRM and CBM procedures used to establish such transmission transfer capability margins as necessary. TRM and CBM should be developed and applied as separate and independent components of transfer capability margin. The specific methodologies for determining and identifying necessary margins may vary among Regions, subregions, power pools, individual systems, and load serving entities. However, these methodologies must be well documented and consistently applied.

TECHNICAL BASIS

Electric systems historically have recognized the need for and benefits of transfer capability margins in the planning and operation of the interconnected transmission networks. In addition to meeting obligations for service to native load customers and deliveries for third-party transmission users, some reserve transmission transfer capability is required to ensure that the interconnected network is secure under a wide range of uncertain operational parameters. Also, systems have relied upon transmission import capability, through interconnections with neighboring systems, to reduce their installed generating capacity necessary to meet generation reliability requirements and provide reliable service to native load. With the introduction of mandatory, non-discriminatory access, and the resulting need to identify and provide current and projected ATCs to the competitive electric power market, a need now exists to formally address these two types of transmission transfer capability margins.

This report provides a framework to support the development of transfer capability margin procedures. TRM and CBM are concepts that may need to be further developed for general applicability while allowing for tailoring to specific Regional, subregional, power pool, and individual system conditions. As these margin concepts are developed and applied, NERC will review their implementation and consider the need for further guidance.

DEFINITION OF TRANSMISSION RELIABILITY MARGIN

Transmission Reliability Margin (TRM) is defined as that amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.

TRM provides a reserve of transfer capability that ensures the reliability of the interconnected transmission network. All transmission system users benefit from the assurance that transmission services will be reliable under a broad range of potential system conditions. TRM accounts for the inherent uncertainty in system conditions and their associated effects on TTC and ATC calculations, and the need for operating flexibility to ensure reliable system operation as system conditions change.
Uncertainty in TTC and ATC Calculations
TTC and ATC determinations depend upon a myriad of assumptions and projections of system conditions, which may include such items as transmission system topology, projected customer demand and its distribution, generation dispatch, location of future generators, future weather conditions, available transmission facilities, and existing and future electric power transactions. Such parameters are assembled to produce a scenario to be used to project transfer capabilities under a reasonable range of transmission contingencies as specified in Regional, subregional, power pool, and individual system reliability operating and planning policies, criteria, or guides. Therefore, calculations of future TTCs and ATCs must consider the inherent uncertainties in projecting such system parameters over longer time periods. Generally, the uncertainties of TTC and ATC projections increase for longer term projections due to greater difficulty in being able to predict the various system assumptions and parameters over longer time periods. For instance, locations of future customer demands and generation sources are often quite uncertain, and these parameters have a potentially large impact on transfer capabilities. Similarly, future electric power transactions are inherently uncertain and can have significant impacts on transmission loadings. Therefore, the amount of TRM required is time dependent generally with a larger amount necessary for longer time projections than for near-term conditions. TRM must also have wide-area coordination.

Need for Operating Flexibility
TTC and ATC calculations must recognize that actual system conditions may change considerably in short periods of time due to changing operating conditions, and cannot be definitively projected without the provision of a transfer capability margin. These operational conditions include changes in dispatch of generating units, simultaneous transfers scheduled by other systems that impact the particular area being studied, parallel path flows, maintenance outages, and the dynamic response of the interconnected systems to contingencies (including the sudden loss of generating units).

Definition of Capacity Benefit Margin
Capacity Benefit Margin (CBM) is defined as that amount of transmission transfer capability reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements. Reservation of CBM by a load serving entity allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements.

The CBM is a more locally applied margin than TRM, which is more of a network margin. As such, to the extent a load serving entity maintains policies and procedures to reserve transfer capability for generation reliability purposes, the CBM should be included in the reserved or committed system uses in the calculation of ATC. These CBMs should continue to be a consideration in transmission system development. It is anticipated that individual load serving entities and regional planning groups will continue to address CBMs and that the NERC and Regional reviews of generation adequacy will continue to consider this capability. It is also anticipated that load serving entities will develop additional procedures for reserving transfer capability for generation capacity purposes and include these procedures in Regional planning reviews and regulatory filings as appropriate.
ATC Definition and Determination

Definition of Available Transfer Capability

Available Transfer Capability (ATC) is a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. Mathematically, ATC is defined as the Total Transfer Capability (TTC) less the Transmission Reliability Margin (TRM), less the sum of existing transmission commitments (which includes retail customer service) and the Capacity Benefit Margin (CBM). ATC can be expressed as:

\[ ATC = TTC - TRM - \text{Existing Transmission Commitments (including CBM)} \]

The ATC between two areas provides an indication of the amount of additional electric power that can be transferred from one area to another for a specific time frame for a specific set of conditions. ATC can be a very dynamic quantity because it is a function of variable and interdependent parameters. These parameters are highly dependent upon the conditions of the network. Consequently, ATC calculations may need to be periodically updated. Because of the influence of conditions throughout the network, the accuracy of the ATC calculation is highly dependent on the completeness and accuracy of available network data.

Determination of Available Transfer Capability

The determination of ATCs and the relationship of electric power transactions and associated power flows on the transmission network are described in Appendixes A and B. The ATC calculation methodologies described in Appendixes A and B are not intended to prescribe a specific calculation procedure nor do they describe the only methods of calculating ATCs. Each Region, subregion, power pool, and individual system will have to consider the ATC Principles in this report and determine the best procedure for calculating ATCs based upon their respective circumstances.

Appendix A describes an ATC calculation approach that may be termed a “network response” method. This method is intended to be illustrative of a procedure that is applicable in highly dense, meshed transmission networks where customer demand, generation sources, and the transmission systems are tightly interconnected.

Appendix B describes another ATC calculation approach that may be referred to as a “rated system path” method. This method is intended to be illustrative of a procedure that is applicable in so-called sparse transmission networks where the critical transmission paths between areas of the network have been identified and rated as to their achievable transfer loading capabilities for a range of system conditions.

Commercial Components of Available Transfer Capability

To more fully define ATC, specific commercial aspects of transmission service must be considered. Because the terms “firm” and “non-firm” are used somewhat loosely within the electric industry, confusion often exists when these terms are used to characterize the basic nature of transmission services. To create reasonably consistent expectations regarding the transmission services that are being offered, the concepts of curtailability and recallability are introduced.
Curtailability
Curtailability is defined as the right of a transmission provider to interrupt all or part of a transmission service due to constraints that reduce the capability of the transmission network to provide that transmission service. Transmission service is to be curtailed only in cases where system reliability is threatened or emergency conditions exist. Curtailment procedures, terms, and conditions will be identified in the transmission service tariffs. When such constraints no longer restrict the transfer capability of the transmission network, the transmission service may be resumed. Curtailment does not apply to situations in which transmission service is discontinued for economic reasons.

Recallability
Recallability is defined as the right of a transmission provider to interrupt all or part of a transmission service for any reason, including economic, that is consistent with FERC policy and the transmission provider’s transmission service tariffs or contract provisions.

Based on the recallability concept, two commercial applications of ATC are defined below and depicted graphically in Figure 2. They are as follows:

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Figure 2: TTC, ATC, and Related Terms in the Transmission Service Reservation System
ATC Definition and Determination

€ Non-recallable Available Transfer Capability — Non-recallable ATC (NATC) is defined as TTC less TRM, less non-recallable reserved transmission service (including CBM). NATC has the highest priority use of the transmission network. The maximum amount of non-recallable service that can be reserved is determined based on what the network can reliably handle under normal operating conditions and during appropriate contingencies as defined in NERC, Regional, subregional, power pool, and individual system reliability operating and planning policies, criteria, or guides. Any lower priority service can be displaced by non-recallable service that is either new non-recallable service or non-recallable service that had been reserved but not scheduled.

Mathematically, NATC can be expressed as:

\[ \text{NATC} = \text{TTC} - \text{TRM} - \text{Non-recallable Reserved Transmission Service (including CBM)} \]

€ Recallable Available Transfer Capability — Recallable ATC (RATC) is defined as TTC less TRM, less recallable transmission service, less non-recallable transmission service (including CBM). Portions of the TRM may be made available by the transmission provider for recallable use, depending on the time frame under consideration for granting additional transmission service. To the extent load serving entities reserve transmission transfer capability for CBM, portions of CBM may be made available for recallable use, depending on the time frame under consideration for granting additional transmission service.

RATC has the lowest priority use on the transmission network and is recallable subject to the notice provisions of the transmission service tariffs. Recallable reserved service may be recalled in favor of subsequent requests for non-recallable transmission service. However, recallable reserved service has precedence over subsequent requests for recallable transmission service, unless the tariff or contract provisions specify otherwise. Because RATC is recallable on short notice, it can use the transfer capability reserved for higher priority service that has been reserved but not scheduled.

RATC must be considered differently in the planning and operating horizons. In the planning horizon, the only data available are recallable and non-recallable transmission service reservations, whereas in the operating horizon transmission schedules are known.

Mathematically, RATC can be expressed as:

a) Planning Horizon

\[ \text{RATC} = \text{TTC} - \text{a(TRM)} - \text{Recallable Reserved Transmission Service} - \text{Non-recallable Reserved Transmission Service (including CBM)} \]

where \( 0 \leq a \leq 1 \), value determined by individual transmission providers based on network reliability concerns.
### ATC Definition and Determination

b) Operating Horizon

\[ \text{RATC} = \text{TTC} - b(\text{TRM}) \]

- Recallable Scheduled Transmission Service
- Non-recallable Scheduled Transmission Service (including CBM)

where \(0 < b < 1\), value determined by individual transmission providers based on network reliability concerns.

NATC and RATC are depicted graphically in Figure 2. TTC, ATC, and related terms in the transmission service reservation system are also shown in Figure 2. In general, the transition between the planning and operating horizons will be a function of available information about the system, the status of reserved and scheduled transmission services, and time considerations.

### Recallable and Non-recallable Relationships and Priorities

The relationships and priorities of recallable and non-recallable concepts as they apply to both scheduled and reserved transmission services are described below. In addition, the interaction between recallable and non-recallable transmission services and the effects on ATC values are discussed and illustrated.

**Scheduled and Reserved Transmission Service**

Reserved transmission service constitutes a reserved portion of the transmission network transfer capability, but the actual electric power transfer is not yet scheduled between areas. Scheduled transmission service indicates that an electric power transfer will be occurring on the transmission network for the time period for which the transmission service was reserved. Both terms can apply to either recallable or non-recallable transmission service, giving the following four transmission service terms:

- Non-recallable Reserved (NRES)
- Non-recallable Scheduled (NSCH)
- Recallable Reserved (RRES)
- Recallable Scheduled (RSCH)

The aggregate of the NSCH and RSCH must never exceed the TTC in the operational horizon. However, in the planning horizon, individual transmission providers may allow the aggregate of the NRES and RRES to exceed the TTC less TRM, to more fully utilize transmission assets, provided that NRES by itself never exceeds TTC less TRM. Such over-subscription of recallable reservations must be disclosed to the purchasers of RRES. These ATC relationships are shown in Figure 3.
ATC DEFINITION AND DETERMINATION

Transmission Service Priorities
Non-recallable and recallable transmission service must adhere to a standard set of priorities universally applied throughout the electric power market to avoid confusion. These priorities are described below:

- Non-recallable service has priority over recallable service. Recallable transfers, reserved or scheduled, may be recalled for non-recallable requests. Recallability will generally be applied as needed only in areas of network constraint and not unilaterally over the entire network.

- All requests for transmission service will be evaluated in priority as established by applicable transmission service tariffs.

- Reserved transfer capability may be used by recallable scheduled transfers, provided that those scheduled transfers can be recalled if the reserved transfer requester wants to make use of the reserved transfer capability.
Several of the possible relationships of NATCs and RATCs to the different types of transfers that have been scheduled or reserved during a given time period are shown in Figure 4 and described below. These concepts apply to any time during the forecast period. Therefore, no time aspect is identified.

Figure 4: ATC Relationships and Priorities
ATC DEFINITION AND DETERMINATION

– Non-recallable scheduled (NSCH) transfers are of the highest priority (all Examples). NSCH transfers cannot be curtailed by the transmission provider except in cases where system reliability is threatened or an emergency exists. All NSCH transfers reduce the amount of ATC.

– Recallable ATC (RATC) can include transfer capability that is currently held by non-recallable reserved (NRES) transfers. However, the new transfers scheduled from the RATC may have to be interrupted if the NRES transfer requester wants to make use of the transmission network (Example 1).

– Non-recallable ATC (NATC) cannot include transfer capability that is currently held by non-recallable reserved (NRES) transfers because the reserved transfer would have priority over any new non-recallable transfer (Examples 1 and 3).

– Non-recallable ATC (NATC) can include transfer capability that is currently used by recallable scheduled (RSCH) transfers because a non-recallable transfer has priority over recallable transfers (Example 3).

– Recallable ATC (RATC) cannot include transfer capability that is currently used by recallable scheduled (RSCH) transfers because the scheduled transfer would have priority over any new transfers (Examples 2 and 3).

– Both non-recallable ATC (NATC) and recallable ATC (RATC) can include recallable reserved (RRES) transfers (all Examples). However, any new recallable transfers may have to be interrupted if the RRES requester wants to make use of the transmission network (Examples 2 and 3).

The Examples in Figures 3 and 4 illustrate how ATC may be applied in the conduct of commercial business. These definitions have no impact on the physical determination of how much additional transfers the network can support.

Appendix C further demonstrates the interaction between recallable and non-recallable transmission service and the effects on ATC values.
The example in this Appendix describes an ATC calculation approach that may be termed a “network response” method. It demonstrates the ATC Principles described in this report and the physical impacts of electric power transfers on an interconnected transmission network. The method is intended to be illustrative of a procedure that is applicable in highly dense, meshed transmission networks where customer demand, generation sources, and the transmission systems are tightly interconnected. In such networks, transmission paths critical to a particular electric power transfer cannot generally be identified in advance. The critical path will be very much a function of the conditions that exist at the time the transfer is scheduled. The example does not introduce any concepts not covered in the front or main portion of this report.

**Physical System Impacts of Transfers**

Determination of ATC requires some translation from the area to area transactions to the resultant electric power flows on the transmission network. This translation is done by stressing the system with appropriate transfers under critical contingencies to determine the characteristic response of the network. These network response characteristics, which are based on the line outage, power transfer, and outage transfer distribution factors of NERC’s May 1995 NERC Transmission Transfer Capability reference document, can be determined by transfer capability studies either beforehand, or on a transaction-by-transaction basis.

When electric power is transferred between two areas such as Area A to Area F in Figure A1, the entire network responds to the transaction. The power flow on each transmission path will change in proportion to the response of the path to the transfer. Similarly, the power flow on each path will change depending on network topology, generation dispatches, customer demand levels, other transactions through the area, and other transactions that the path responds to which may be scheduled between other areas.

![Figure A1: Network Response Characteristics for Area A to Area F Transfers](image-url)
To illustrate this, computer simulation studies are performed to determine the transfer capability from Area A to Area F. During that process, it is determined that 77% of electric power transfers from Area A to Area F will flow on the transmission path between Area A and Area C (Figure A1).

Through application of those response characteristics, the impact on the path between Area A and Area C for a 500 MW transfer from Area A to Area F is graphically described in Figure A2. In this example, a pre-existing 160 MW power flow exists from Area A to Area C due to a generation dispatch and the location of customer demand centers on the modeled network. When a 500 MW transfer is scheduled from Area A to Area F, an additional 385 MW (77% of 500 MW) flows on the transmission path from Area A to Area C, resulting in a 545 MW power flow from Area A to Area C.

To determine the ability of the network to transfer electric power from Area A to Area F, additional potential impacts within the individual areas must also be recognized. The network responses shown in Figure A1 must be expanded to consider possible transmission limits within each area.

The response characteristics of limiting facilities within the individual areas for an Area A to Area F transfer are shown in Figure A3. For simplicity, the flows within each area are not shown. Rather, the figures within each area represent the percentage of the transfer from Area A to Area F that flows on the most limiting facility within each area. Recognition of the limiting path responses within the individual areas for Area A to Area F transfers increases the complexity of determining the Area A to Area F ATC.
TRANSLATION OF SYSTEM IMPACTS TO ATC

The ATC of the network depends on the existing loading conditions on the limiting transmission facility, wherever it may be, taking into account contingency criteria (i.e., outage of the most critical line or generator or multiple lines and generators, as appropriate).

ATC is a function of how much unused or unloaded capacity is available on the most limiting transmission facility, allowing for single and, in some cases, multiple contingencies. The translation of the unused capability of the transmission network to ATC determination for a particular direction is illustrated in Table 1, which refers to the transmission network shown in Figure A3 for an Area A to Area F transfer. The unused capacity of individual facilities in the transmission network, which is the difference between a facility’s rating and its current power flow loading or its “available loading capacity,” is divided by the response characteristic of the path facility to an Area A to Area F transfer. This procedure provides the individual critical path ATCs (in a system or between systems) from which the ATC from Area A to Area F is then determined by considering the most limiting path ATC. In this case, the limiting path is in Area D and the Area A to Area F ATC is 1,200 MW.

For a different electric power transfer, a new set of network responses and a new set of available capacity on limiting facilities would need to be determined to define the ATC for that transfer.

Electric power transfers have historically been scheduled between control areas on a contract path or area interchange basis. However, in the determination of ATCs, the actual flows on the network must be considered regardless of the scheduling methodology. In the preceding example, an electric power transfer may be scheduled from Area A to Area F, using a contract path from Area A to Area C to Area F. However, the reality of alternating current electrical systems is that the electric power would flow from Area A to Area F over the entire network, governed by the laws of physics. The electric power flowing on portions of the network other than the scheduled contract path is known as parallel path...
Available Transfer Capability Definitions and Determination

Table 1: Available Transfer Capability Matrix for Transfers from Area A to Area F

flows, and can affect many systems in an interconnected network. In this particular example, the transmission limit in Area D limits the Area A to Area F transfers to 1,200 MW.

**ATC Time Variation and Network Dependency**

Network conditions will vary over time, changing line loading conditions, and causing the ATC of the network to change. Also, the most limiting facility in determining the network’s ATC can change from one time period to another, particularly in highly meshed networks. Therefore, the ATC of the network is time dependent.
APPENDIX A. NETWORK RESPONSE METHOD FOR ATC DETERMINATION

This characteristic is illustrated conceptually in Figure A4. The first group of graphs on the left-hand side of the figure presents the available loading capacity at different points in time (T₁, T₂, T₃) for several lines in an interconnected network. If an Area A to Area B transfer is to be scheduled at T₁, each of the lines (line 1 in Area A, line 3 in Area B, line 7 in Area B, and line 16 in Area D) will respond to the transfer in accordance with its network response factor. This factor is used to determine an ATC as limited by each individual facility. The results are shown on the middle set of diagrams of Figure A4. The ATC for the network as a whole represents the minimum of the ATCs as defined by each facility at each time frame. These minimum ATCs are schematically illustrated in the right side of Figure A4. As demonstrated, the ATC is different for each time period and is determined by a different facility in each period.

![Figure A4: ATC Variance](image-url)
The determination of ATC and the difference between simultaneous and non-simultaneous transfers are demonstrated in Tables 2 and 3. These ATC demonstrations are based on the sample six system network shown in Figure A3.

### Table 2: Non-Simultaneous ATC Analyses

Table 2 presents the non-simultaneous ATC analyses for three representative transfer conditions: Area A to Area F, Area B to Area E, and Area E to Area A. For each transfer direction, the area to area ATC is determined by the most critical system contingency and the resultant limiting system element, varying from 500 MW for an Area B to Area E transfer (limited by line B1 in Area B) to 1,470 MW for an Area E to Area A transfer (limited by line A2 in Area A).

<table>
<thead>
<tr>
<th>Area A to Area F Transfer</th>
<th>Facility</th>
<th>Network Response (%)</th>
<th>ALC* on Limiting Facility (MW)</th>
<th>Area to Area ATC (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Area A to Area F Transfer</td>
<td>D D1</td>
<td>15</td>
<td>180</td>
<td>1,200</td>
</tr>
<tr>
<td>Area B to Area E Transfer</td>
<td>B B1</td>
<td>5</td>
<td>25</td>
<td>500</td>
</tr>
<tr>
<td>Area E to Area A Transfer</td>
<td>A A2</td>
<td>7</td>
<td>103</td>
<td>1,470</td>
</tr>
</tbody>
</table>

*Available Loading Capacity

### Table 3: Simultaneous ATC Analyses

<table>
<thead>
<tr>
<th>Area A to Area F ATC Analysis</th>
<th>Facility</th>
<th>Network Response (%)</th>
<th>ALC* on Limiting Facility (MW)</th>
<th>Area to Area ATC (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Area A to Area F ATC Analysis With a Pre-existing Area B to Area E 500 MW Transfer</td>
<td>B B1</td>
<td>3.5</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Area A to Area F ATC Analysis With a Pre-existing Area B to Area E 500 MW Transfer and a Pre-existing Area E to Area A 1,470 MW Transfer</td>
<td>B B1</td>
<td>3.5</td>
<td>40</td>
<td>1,140</td>
</tr>
</tbody>
</table>

*Available Loading Capacity
APPENDIX A. NETWORK RESPONSE METHOD FOR ATC DETERMINATION

The first section of Table 3 shows a determination of ATC for an Area A to Area F transfer, assuming that an Area B to Area E 500 MW transfer schedule is already in effect. Under this condition, the Area A to Area F ATC is now reduced from 1,200 MW (Table 2) to zero. This change is due to the increased loading on line B1 due to the previously scheduled 500 MW transfer from Area B to Area E, making it the limiting network facility. Note that the Area A to Area F transfer limiting facility was line D1 in Area D in the non-simultaneous analysis (Table 2).

The second portion of Table 3 is another determination of ATC for an Area A to Area F transfer. In this example, pre-existing transfers are in place from Area B to Area E of 500 MW and Area E to Area A of 1,470 MW. Under these conditions, the ATC for an Area A to Area F transfer is found to be 1,140 MW. This transfer is a slight reduction from the 1,200 MW ATC determination in the non-simultaneous case (Table 2), but is a significant increase from the zero ATC found in the previous case (first part of Table 3). This increased transfer is due to the offsetting effect of the flows caused by the pre-existing Area E to Area A transfer, which reduced the line loading on the critical facility B1, thus increasing the ATC for the Area A to Area F transfer direction.

These examples demonstrate that the determination of ATC in a tightly interconnected network is very much a function of system conditions that exist on the network at the time the transfer is to be scheduled. In addition, ATC is a function of the specifics of the electric power transfer being considered in terms of its direction, amount, and duration. To be able to properly appraise the performance of tightly interconnected networks to support contemplated transfers (i.e., what is the ATC), a regional or wide-area approach must be considered so that all network conditions are properly taken into account.
APPENDIX B. RATED SYSTEM PATH METHOD FOR ATC DETERMINATION

OVERVIEW

The rated system path (RSP) method for ATC determination is typically used for transmission systems that are characterized by sparse networks with customer demand and generation centers distant from one another. Generally in this approach, paths between areas of the network are identified and appropriate system constraints determined. ATC is computed for these identified paths and interconnections between transmission providers.

The RSP method involves three steps: 1) determining the path’s Total Transfer Capability (TTC), 2) allocating the TTC among owners in a multi-owned path to determine the owners’ rights, and 3) calculating ATC for each right-holder by subtracting each of their uses from each of their individual TTC rights. Wide-area coordination is achieved by developing the TTC in a manner that follows a regional review process. This process assures individual, power pool, subregional, and Regional coordination and the necessary consideration of the interconnection network’s constraints and conditions.

The RSP method includes a procedure for allocating TTC, and in turn ATC, among the owners of the transmission path(s). It should be noted that the RSP method of allocation is not the only procedure that may be followed in allocating transmission services.

UNSCHEDULED FLOW OR PARALLEL PATH FLOW

The RSP approach accounts for the effects of unscheduled flow (parallel path flow) on interconnected systems through the modeling of realistic customer demand and generation patterns in advance of real-time operations, and uses a maximum power flow test to ensure that the transfer path is capable of carrying power flows up to its rated transfer capability or TTC.

The rating process begins by modeling the interconnected network with the actual flow that will occur on the path and its parallel paths under realistically stressed conditions. The lines comprising the path may be rated and operated as a single path. The network is tested under a wide range of generation, customer demand, and facility outage conditions to determine a reliability-based TTC. When determined this way, the TTC rating usually remains fairly constant except for system configuration changes such as a line outage situation. To implement the RSP ATC method, consistent path rating methods and procedures must be agreed upon and followed within the Interconnection.

Non-simultaneous ratings are normally used as the basis for calculating ATC. If, however, two rated paths have a simultaneous effect on each other, the rating process identifies the simultaneous capabilities or establishes nomograms that govern the simultaneous operation of the paths. Applicable operating procedures are negotiated to ensure reliable network operation. Where simultaneous operation is necessary, operator control is used to ensure safe and reliable operation of the transmission network.
APPENDIX B. RATED SYSTEM PATH METHOD FOR ATC DETERMINATION

CAPACITY ALLOCATION

The reliability-based TTC of a transfer path (its reliability rating) is allocated among the right-holders based upon their negotiated agreement. This determination of the property rights through the allocation process is critical to the RSP implementation of ATC. The rights in the path are negotiated for each of the individual transmission providers. Except for deratings based upon system operating (e.g., emergency) conditions, these allocations become rights that the right-holder may use or resell to others as non-recallable or recallable service.

Although the actual flows from each right-holder’s schedule will flow on all parallel lines, the advance allocation of rights on a path makes it possible for right-holders to determine ATC and sell service within their rights independent of others. If the rating is determined using appropriate path rating procedures, including a maximum power flow test, the potential for adverse unscheduled power flow effects is minimized.

In real time, neither the total of the schedules, nor the actual power flow on a path may exceed the path TTC. Although the potential for adverse unscheduled power flow is minimized as a result of the modeling and rating process, some acceptable or mitigable unscheduled flows will usually occur during real-time operation. Regions that use RSP to calculate ATC should adopt an unscheduled flow mitigation plan which addresses such flows, if they adversely affect system operation. The adverse flows can be managed through schedule changes, installing controllable devices such as phase shifters, or including this uncertainty as part of the reliability margin.

ATC CALCULATION APPROACH

1. Each path for which ATC must be calculated is identified, and then a reliability-based TTC is determined as described above. This TTC is then allocated among the owners by negotiated agreement.

2. Deratings for outages, nomograms, maintenance, or unscheduled flow are allocated, if necessary, to the right-holders based on prearranged agreements or tariffs.

3. Right-holders take their respective allocated shares of the TTC for a path and subtract the existing commitments to determine the appropriate ATC.

4. Right-holders update and repost their ATC calculations as new commitments impact their ATC. A transfer from one area to another involving several transmission owners requires locating and reserving capacity across multiple paths and potentially multiple right-holders.

EXAMPLE OF ATC DETERMINATION

The following example illustrates the application of the RSP method for determining ATC in a sparse network. The example transmission network is shown in Figure B1. All paths that connect the various areas have transfer capabilities that were individually developed in coordination with all areas giving consideration to unscheduled flow and interconnection interactions and effects. The TTCs portrayed in
APPENDIX B. RATED SYSTEM PATH METHOD FOR ATC DETERMINATION

Figure B2 are shown for each path and are directional, but are not necessarily the same for each direction.

![Sparse Network Model](image1)

Figure B1: Sparse Network Model

![Total Transfer Capabilities](image2)

Figure B2: Total Transfer Capabilities

Each path may consist of several transmission lines that can also have different owners. In this example, the path between Areas B and D is comprised of five lines as shown in Figure B3. The TTC from Area B to Area D is 7,500 MW and, in the reverse direction, 8,800 MW. Line 1 is owned by a single entity and has an allocated portion of the TTC equal to 1,300 MW in either direction.
This example reflects a snapshot in time during the planning horizon. Initial transmission service reservations, all assumed to be non-recallable, are shown for each path in Figure B4. The corresponding ATC for each path has been calculated by subtracting the non-recallable service from the TTC. Because all the transmission service reservations are assumed on each path to be in one direction, the path ATC is only calculated for that direction.
For example, referring to Figure B4, the ATC from Area B to Area D is calculated as 7,500 MW less 4,000 MW or 3,500 MW. For line 1 of the B to D path, the ATC is 1,300 MW less 200 MW or 1,100 MW. In the next case, as shown in Figure B5, 1,000 MW of non-recallable transmission service is acquired from Area A to Area B to Area D. No other changes occur. The total transmission service reserved from Area A to Area B is 1,500 MW, and the resulting ATC goes to zero. The ATC from Area B to Area D reduces to 2,500 MW (7,500 MW TTC less 5,000 MW reserved transmission service). It is assumed the 1,000 MW of the new reserved transmission service was obtained from the owner of line 1, resulting in the total reserved transmission service on this line being 1,200 MW. The new ATC for line 1 is 100 MW (1,300 MW TTC less 1,200 MW reserved transmission service).

![Figure B5: New Transmission Service Reservation on Path A to B to D](image)

The non-recallable transmission service reserved for a path in each direction may not exceed the path’s transfer capability in either direction under any circumstances. These limits are consistent with NERC Operating Policies.

Unscheduled flow may at times preclude scheduling to a path’s full transfer capability or TTC. If an internal limit is encountered in any system as a result of the transaction from Area A to Area D, for example in Area D, Area D’s system operator must respond to relieve the limitation such as by redispatching generation or using phase shifter control. An unscheduled flow mitigation plan might also be implemented to relieve excessive unscheduled flow problems. Additional relief may be achieved by curtailing schedules that are contributing to the unscheduled flow on the path or by increasing schedules that would create unscheduled flow in the opposite direction. In this example, if path A to D were limiting, unscheduled flow mitigation procedures could be implemented to initiate coordinated operation of controllable devices such as phase-shifting transformers to relieve the limitation.
There will probably be times in the operating horizon when the use of the transmission network results in actual flows on a transmission path being less than the transmission scheduled on the path. During these periods, if the transmission path is fully scheduled, additional electric power may be scheduled to Area D from Area A by reserving transmission service over a different transmission path. In this case, transmission service could be obtained from either the owners of the direct path between Area A and Area D or the owners of the transmission system from Area A to Area C to Area D.

For the RSP method, the transmission rights to be reserved and scheduled by all transmission users are consistent with the rating of the transmission paths. If determined through a coordinated process using models that capture the major effects of the interconnected network, these ratings will create limits that result in the reliable operation of the regional electric system. The owners of the transmission paths, through a negotiated allocation process, will know their transmission service rights and the resulting use of these rights will be consistent with the physical capability and limitations of the transmission network. This RSP method assures efficient use and reliable operation of the interconnected transmission network.
OVERVIEW

The following scenarios demonstrate how the 1,200 MW ATC quantity from Area A to Area F in the example in Appendix A may be commercially employed. The interplay between recallable and non-recallable transmission service and the resulting effects upon calculated ATCs are demonstrated using the equations presented in the “ATC Definition and Determination” section of this report. They clearly demonstrate that, although both recallable and non-recallable ATC are offered simultaneously, the combined total of recallable and non-recallable service does not exceed the TTC at any time.

For the purpose of this illustration, assume that conditions on the interconnected network are as described in Tables 1 and 2 of Appendix A. Under this scenario, the network ATC from Area A to Area F for this time period in the operating horizon is 1,200 MW. Also, for simplicity, assume that previous transmission commitments are zero. Thus, TTC in the following case is 1,200 MW. Lastly, assume that TRM is zero. The resulting relevant simplified ATC equations for the operating horizon are:

\[ \text{NATC} = \text{TTC} - \text{NRES} \]
\[ \text{RATC} = \text{TTC} - \text{RSCH} - \text{NSCH} \]

The equations that describe the TTC constraints during this time frame are:

\[ \text{NRES} \leq \text{TTC} \]
\[ \text{RSCH} + \text{NSCH} \leq \text{TTC} \]

ATC DEMONSTRATION — SCENARIO 1

Consider the initial case identified in Figure C1 as Case 1. Reservations for 200 MW of recallable and 400 MW of non-recallable transmission service have been reserved against the 1,200 MW TTC.

Case 1 includes schedules for only 300 MW of non-recallable transmission service. Thus:

\[ \text{NATC} = \text{TTC} - \text{NRES} \]
\[ = 1,200 - 400 \]
\[ = 800 \text{ MW} \]

\[ \text{RATC} = \text{TTC} - \text{RSCH} - \text{NSCH} \]
\[ = 1,200 - 0 - 300 \]
\[ = 900 \text{ MW} \]
### Figure C1: ATC Demonstration — Scenario 1

In Scenario 1, the transmission customer reserves an additional 100 MW of recallable transmission service and schedules the entire 300 MW recallable reservation. The results are shown in Figure C1 as Case 2. (Note that changed values are shown in bold italic type.) Non-recallable ATC is unchanged, but recallable ATC is changed as follows:

\[
\text{RATC} = \text{TTC} - \text{RSCH} - \text{NSCH} \\
= 1,200 - 300 - 300 \\
= 600 \text{ MW}
\]

<table>
<thead>
<tr>
<th>Transfer Capabilities</th>
<th>Transmission Services</th>
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<tbody>
<tr>
<td>TTC — Total Transfer Capability</td>
<td>NRES — Non-recallable Reserved</td>
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<td>ATC — Available Transfer Capability</td>
<td>NSCH — Non-recallable Scheduled</td>
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<td>RATC — Recallable ATC</td>
<td>RRES — Recallable Reserved</td>
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<td>NATC — Non-recallable ATC</td>
<td>RSCH — Recallable Scheduled</td>
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### APPENDIX C. TRANSMISSION SERVICE RESERVATIONS AND SCHEDULING

#### Available Transfer Capability Definitions and Determination

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**Transfer Capabilities**

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<thead>
<tr>
<th>TTC</th>
<th>Total Transfer Capability</th>
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<tr>
<td>ATC</td>
<td>Available Transfer Capability</td>
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<td>Recallable ATC</td>
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<tr>
<td>NATC</td>
<td>Non-recallable ATC</td>
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<table>
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<tr>
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<td>RRES</td>
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<tr>
<td>NRES</td>
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<td>RSCH</td>
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<tr>
<td>NSCH</td>
<td>300</td>
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<tr>
<td>NATC</td>
<td>800</td>
</tr>
<tr>
<td>RATC</td>
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**Transmission Services**

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<th>NRES</th>
<th>Non-recallable Reserved</th>
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<td>RRES</td>
<td>Recallable Reserved</td>
</tr>
<tr>
<td>RSCH</td>
<td>Recallable Scheduled</td>
</tr>
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</table>

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### ATC DEMONSTRATION — SCENARIO 2

In Scenario 2 of Figure C2, the transmission customer reserves an additional 400 MW of non-recallable transmission service. The results are shown in Figure C2 as Case 3. Recallable ATC is unchanged in this scenario, but non-recallable ATC is changed as follows:

\[
NATC = TTC - NRES
\]

\[
= 1,200 - 800
\]

\[
= 400 \text{ MW}
\]

---

**Figure C2: ATC Demonstration — Scenario 2**
In Scenario 3 of Figure C3, the transmission customer reserves and schedules an additional 300 MW of non-recallable transmission service. The results are shown in Figure C3 as Case 4. In this scenario, both recallable and non-recallable ATCs are changed as follows:

\[
\begin{align*}
\text{NATC} & = \text{TTC} - \text{NRES} \\
& = 1,200 - 1,100 \\
& = 100 \text{ MW} \\
\text{RATC} & = \text{TTC} - \text{RSCH} - \text{NSCH} \\
& = 1,200 - 300 - 600 \\
& = 300 \text{ MW}
\end{align*}
\]

Transmission customers holding the 200 MW of recallable transmission service reservations “above the TTC line” should be advised that they have a high probability of having their transmission service recalled.
Available Transfer Capability Definitions and Determination

**APPENDIX C. TRANSMISSION SERVICE RESERVATIONS AND SCHEDULING**

**Figure C4: ATC Demonstration — Scenario 4**

In Scenario 4 of Figure C4, the transmission customer schedules an additional 400 MW of non-recallable transmission service. The results are shown in Figure C4 as Case 5. Non-recallable ATC remains unchanged at 100 MW. Unless 100 MW of recallable transmission service schedules are recalled, the total schedules violate the TTC constraint. The transmission provider must recall 100 MW of scheduled recallable transmission service. The recallable ATC calculation is then:

\[
\text{RATC} = \text{TTC} - \text{RSCH} - \text{NSCH} = 1,200 - 200 - 1,000 = 0 \text{ MW}
\]

As this demonstration has shown, recallable transmission services may be reduced as non-recallable transmission services are reserved and scheduled, approaching the TTC limit.
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.
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 slowing 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, piped, 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. A “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 “controlled 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 redispatched 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 tested 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.
NERC BACKUP CONTROL CENTER

A Reference Document

EPRI Project RP2473-68
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7. Conclusion

Appendixes

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1. Introduction

This reference document is intended to aid control center managers in scoping, justifying, and planning a backup control center (BUCC). Since control centers differ in their functions and responsibilities, each utility must decide which functions are critical and need to be performed when operating from an alternate location. To aid a utility in justifying and designing its BUCC, key issues to be considered in planning a BUCC are provided. Common issues, such as control center threats and their resultant impacts, are discussed in general terms. Alternative BUCC solutions that are related to a utility’s specific responsibilities within its control area are discussed using prototype situations to further guide a utility based on its own operating requirements.

The information contained in this reference document was obtained both from a search of current literature on backup control centers and from a survey of utility personnel with expertise in the planning and use of backup control centers. Appendix A contains a bibliography of current literature used as reference material. Appendix B contains a copy of the questionnaire used in the utility survey.

Individuals from the following utilities were contacted during the survey process and they provided the bulk of the information included in this document:

- American Electric Power Corporation
- Baltimore Gas & Electric
- Bonneville Power Administration
- Boston Edison Company
- Delmarva Power & Light Company
- Detroit Edison Company
- Entergy Services, Inc.
- Florida Power & Light Company
- General Public Utilities
- Michigan Electric Power Coordination Center
- New England Power Exchange
- New York Power Pool
- Ontario Hydro
- Orange & Rockland Utilities, Inc.
- Pacific Gas & Electric Company
- PJM Interconnection Association
- Pennsylvania Power & Light Company
- Public Service Electric & Gas Company
- Southern California Edison Company
- Tucson Electric Power Company
- Union Electric Company
2. Criteria for Critical BUCC Functional Capabilities

NERC Guide III, G. Recommendation 5 states that the standards of Guide I should be considered when developing the plan to continue operation. The standards of Guide I address the functions of generation control, voltage control, time and frequency control, interchange scheduling, and inadvertent interchange management. In addition, utilities require either manual or automated control of critical substation devices; logging of significant power system events; and, as appropriate, hourly interchange accounting. These functions to the extent they are operating responsibilities of the primary control center provide the minimum set of recommended functional capabilities for a BUCC.

In addition, a BUCC may also be required to support other corporate or power pool responsibilities that are normally performed by the primary control center. For example, power pool accounting or corporate-wide access to historical data may be required.

3. Threat Assessment for the Primary Control Center

Most utilities that have already implemented BUCCs did not perform a quantitative threat assessment. These utilities considered the consequences of a control center loss and the resultant concern for power system security as sufficient justification for implementing a BUCC. This type of qualitative justification is most prevalent among utilities that are located in areas prone to natural disasters.

The objective of performing a threat assessment is to determine the range of control center outages that need to be considered when planning for a BUCC. Brief outages (less than two hours) are not normally considered in a threat assessment, since their incremental impact to operations is small. A quantitative methodology for threat assessment and for BUCC cost justification involves the following steps:

(a) Determine the likelihood of losing a control center  
(b) Quantify the consequences for different disaster scenarios  
(c) Prepare a risk analysis using probabilities and cost consequences

3.1 Control Center Threats

When performing a threat assessment, the following types of events that could disable a control center should be considered:

(a) Natural disasters, such as hurricanes, earthquakes, tornados, floods, and other weather caused conditions. The frequency and severity of these natural disasters can be forecasted by using historical data.
(b) Accidents, such as fire, internal environmental problems, flooding, chemical spills, plane crash, explosion, loss of communications, and other catastrophic events. The frequency of accidental events may be obtained from insurance carriers or other industry experts.
(c) Sabotage, such as bomb threats, software viruses, and other malicious actions. The frequency of these events can be grossly estimated from the use of historical data and from information from other studies.
The overall annual frequency of control center loss is the total of the individual frequency for each of the above three classifications. Based on a utility’s location, the frequency of occurrence for each of these classifications could differ by a few orders of magnitude.

### 3.2 Impact on Control Center Operation

The above threats can result in various impacts to control center operation. The severity of these impacts can range from a forced evacuation of a few minutes up to the complete rebuilding of the control center facility. A comprehensive plan for justifying a BUCC should consider a full range of potential disaster durations, the following ranges of outage durations are appropriate:

(a) Short term — up to 48 hours
(b) Intermediate term — up to two weeks
(c) Long term — over two weeks

Please note, the number of classifications and the outage durations for the classifications can be tailored to the actual circumstances of a particular utility.

The following types of impacts to control center operations should be considered during the threat assessment process:

(a) Impacts that normally result in short-term outages:
   (1) required evacuation of the control center
   (2) loss of communications
   (3) loss of EMS/SCADA system
   (4) loss of critical data
   (5) loss of control center support facilities, such as air conditioning, power, and water

(b) Impacts that may result in intermediate-term outages:
   (1) damage to private microwave system
   (2) severe damage to EMS/SCADA system
   (3) damage to the control center facility

(c) Widespread damage to the control center facility could result in a long-term outage lasting many months

The cost consequences of these outages both with and without a BUCC can then be used in justifying the need for a BUCC.

### 3.3 Worst-Case Scenario

The cost consequences of a control center outage depend upon the state of the power system at the time the disaster occurs. A worst-case scenario would be a disaster that not only caused the loss of the control center facility, but also caused widespread outages in the electrical network. This would result in not only increasing the recovery time for the power system disturbance, but would most likely result in extended hours and deteriorating working conditions for both operating staff and field crews. This could lead to accidents, inaccurate records, and potentially unstable operating conditions. Because the costs associated with this type of worst case scenario would be almost impossible to determine, this document considers only the loss of the control center under normal power system conditions.
4. Justification for a Backup Control Center

As stated before, a utility can take one of two approaches for justifying a BUCC: a qualitative justification that discusses the costs of a control center loss and benefits of a BUCC in general terms, and a quantitative risk analysis that develops a complete cost justification for a BUCC. While gathering information for this document, it became apparent that most utilities with a BUCC performed a qualitative analysis to justify a “bare bones” backup facility.

4.1 Qualitative Justification

A qualitative justification is usually based on an opportunistic occurrence where the incremental cost to add a BUCC is small, such as the procurement of an EMS or the installation of a SCADA system at a remote regional control center. Where the threat of natural disasters and/or sabotage are significantly greater, a more sophisticated BUCC facility is more readily justified because of management’s concern for power system security or by other outside pressures.

Qualitative justifications should be based on NERC Guide III.G. criterion that control centers have plans and backup capability to avoid placing burdens on neighboring control areas. The cost of implementing these plans, including any cost to transfer control to an adjacent control area, purchase regulating service, or to operate the system in a conservative manner to assure system security, should be compared to the cost of implementing a BUCC.

4.2 Quantitative Risk Analysis

When performing a quantitative risk analysis, the following issues need to be considered:

(a) The change in average daily production cost with and without a BUCC  
(b) Loss of revenue from potential interchange transactions  
(c) Cost of additional staffing to support manual operations from critical locations for an extended period of time  
(d) Effects on power system security based on potential loss of equipment due to lack of network security software  
(e) Costs for training operators to work under emergency conditions from a backup facility for an extended period of time

The cost for each of the above items will be affected by the functional capabilities implemented in the BUCC. Different risk scenarios can then be used to evaluate the appropriate level of BUCC functionality. In disaster planning, the amount of resources worth investing in emergency facilities is evaluated using risk analysis. In this content:

Risk = Consequences x Frequency

In justifying a BUCC, the consequence is the cost difference between operating with and without a BUCC. This cost difference must take into account the different yearly probabilities and estimated outage durations. The frequency is the expected frequency of loss of the primary control center as discussed in Section 3.1. Risk can then be quantified as an Expected Annual Cost (EAC). The expected useful life of the BUCC must be used with the EAC in calculating the present worth of the BUCC. The
dollar amount worth spending on a BUCC is equal to its present worth. Clearly, this is not a precise analysis method.

4.3 Scope of the BUCC

The cost justification of expensive disaster recovery facilities is made difficult by the extremely low historical frequency of control center disasters. The low probability of an individual utility experiencing a disaster tends to justify only low budgets for a BUCC. This has led utilities to use manned backup facilities with only radio and telephone communications to monitor and control the power system during a control center disaster or outage. This method provided an initial low cost solution; but, in the long term, it was expensive to develop and maintain an adequate set of manual operating procedures. An increasing risk associated with a BUCC that relies on manual operating procedures is the inability of system operators to manage the complexities of a power system over an extended period of time without automated tools. For this reason, a manual control-oriented BUCC should only be considered as an adequate backup for short-term outages (up to 48 hours), and should not be used for protection against disasters that render the primary control center unusable for several days or more.

5. Alternative Solutions for Backup Control Centers

This section discusses alternative BUCC solutions in terms of control center prototypes that are used to represent a range of utility operating responsibilities in a control area. These prototypes are then used to discuss the metering and communications requirements that are necessary to support the critical BUCC functions as described in Section 1. Later sections discuss alternative BUCC solutions based on these prototypes.

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<th>Control Center (CC) Configuration</th>
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<tr>
<td>1</td>
<td>Primary control center performs complete control area dispatch</td>
<td>Single primary control center</td>
</tr>
<tr>
<td>2</td>
<td>Primary control center performs complete control area dispatch</td>
<td>Primary control center with subordinate control centers</td>
</tr>
<tr>
<td>3</td>
<td>Primary control center performs AGC but does not directly control generating units</td>
<td>Primary control center with subordinate control centers</td>
</tr>
<tr>
<td>4</td>
<td>Control center does not perform AGC but sends control signals to generating units</td>
<td>Single control center</td>
</tr>
<tr>
<td>5</td>
<td>Control center does not perform AGC but sends control signals to generating units</td>
<td>Control center with subordinate controls centers</td>
</tr>
<tr>
<td>6</td>
<td>Control center has no involvement in AGC</td>
<td>May or may not have subordinate control centers</td>
</tr>
</tbody>
</table>
5.1 BUCC Metering and Communication Requirements

Regardless of the level of sophistication of the BUCC, the most important considerations when implementing a BUCC is the availability of both voice and data communication facilities. Providing adequate communications is the major portion of the cost for a BUCC. It is essential for system operators at the BUCC to have voice communications with operating personnel that they normally communicate with from the primary control center. If the BUCC is to include data monitoring and supervisory control, the communications facilities must also include data channels to remote terminal units located at key substations. Data channels may also be required to send control signals to generating plants or subordinate control centers as appropriate. The following table provides the metering and communications requirements for each of the BUCC prototypes.

<table>
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<th>BUCC Metering &amp; Communication Requirements</th>
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<td></td>
<td>1</td>
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<tr>
<td>1. Instantaneous tie-line MW and Mvar telemetry</td>
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<tr>
<td>2. Instantaneous generating unit MW telemetry</td>
<td>✓</td>
</tr>
<tr>
<td>3. MWh accumulator readings for all tie lines and generating units</td>
<td>✓</td>
</tr>
<tr>
<td>4. SCADA for generating units</td>
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</tr>
<tr>
<td>5. SCADA for unmanned, critical substations</td>
<td>✓</td>
</tr>
<tr>
<td>6. System frequency and time error measurements</td>
<td>✓</td>
</tr>
<tr>
<td>7. Data links to send generation control signals to subordinate centers</td>
<td>–</td>
</tr>
<tr>
<td>8. Voice communications to manned power plants</td>
<td>✓</td>
</tr>
<tr>
<td>9. Voice communications to manned, critical substations</td>
<td>✓</td>
</tr>
<tr>
<td>10. Voice Communications to subordinate control centers</td>
<td>–</td>
</tr>
<tr>
<td>11. Voice communications to higher-level control center</td>
<td>–</td>
</tr>
<tr>
<td>12. Voice communications to neighboring control centers</td>
<td>✓</td>
</tr>
</tbody>
</table>
5.2 BUCC Alternative Solutions

The BUCC alternatives available to an electric utility range from a basic “war room” equipped with system maps, diagrams, telephones, radios, and manual procedure documents to a full-function replica of the primary control center complete with most, if not all, application software used for control of the power system. As the level of sophistication of the BUCC facility increases, so in general, does its initial implementation cost. However, the ongoing support cost of a BUCC is normally inversely proportional to its degree of sophistication due to the costs associated with developing, maintaining, and teaching the skills and procedures required to support the manual operation of the power system. The following sections list the configuration alternatives for implementing a BUCC at utilities with and without subordinate control centers.

5.2.1 Utilities Without Subordinate Control Centers (Prototypes 1, 4 and possibly 6)

These utilities are at a disadvantage in that there is no obvious location, such as a divisional control center, to assume the backup control functions if the primary control center is disabled. The solution is to select an existing facility, such as a previous control center site or an office facility, that has access to the communications facilities and thus can be provided with the data necessary to perform the required BUCC functions. The selected facility should be sufficiently removed from the primary control center in order to isolate it from the same threats that may render the primary control center inoperable.

The following types of alternative configurations can be deployed at the BUCC depending upon the level of functionality required:

(a) A remote facility with a complete backup EMS/SCADA system (either a single or dual processor). This configuration provides full functionality at the BUCC, but also requires a large amount of telemetry and data to support it. The use of a retired EMS or SCADA system to perform as the BUCC is a way to reduce the initial implementation cost; however, the long-term maintenance costs are usually high due to a lack of spare parts, inadequate documentation, and cumbersome software/database maintenance tools.

If the BUCC is an exact duplicate or a subset of the primary control center, then the BUCC could also be used as a remote maintenance site for troubleshooting hardware, as an additional source for critical spare parts, and as a remote test site for newly developed or modified software.

(b) A remote facility with reduced functionality using one or more workstations and/or personal computers. This configuration provides the most functional flexibility and ease of expansion. Advancements in networking and distributed systems/database technologies have allowed utilities to implement a basic set of SCADA/AGC functions on microprocessor-based platforms that can be easily expanded in the future via third-party software products that run under standard operating systems, such as UNIX and DOS. Custom operating procedures and software/database maintenance tools must be developed to support this type of BUCC configuration.

(c) A remote facility with minimum requirements that is used for manual dispatch. A utility must determine if adequate system regulation can be maintained using manual
generation control. As mentioned above, manual operation from a BUCC should only be considered as a backup strategy for short-term emergencies. Specific plans and procedures should be in place for establishing an adequate backup facility if a longer-term outage occurs at the primary control center. This may be accomplished either by an agreement with a neighboring utility to provide backup control area capability or by acquiring backup equipment and communications at the BUCC under emergency conditions. If a neighboring utility is to provide adequate system regulation, then tie line MW telemetry must be made available to it.

5.2.2 Utilities with Subordinate Control Centers (Prototypes 2, 3, 5 & possibly 6)

These utilities may use any of the BUCC configurations described in the previous section and also have access to the facilities of the subordinate control centers. Once again, the communications system is key to the functionality of the BUCC. If one or more of the subordinate control centers has access to all of the data available to the primary control center, it is possible to duplicate the functionality of the primary control center by locating the BUCC at the subordinate control center. Otherwise, the functionality of the BUCC will be limited to the data available at the subordinate control center site.

In addition to the configurations described in Section 5.2.1, the BUCC control system at a subordinate control center may also take the following forms:

(a) A stand-alone system (either single or dual processor) that utilizes the subordinate control center’s communication facilities. This configuration minimizes the impact of any BUCC activities on the existing computer system.

(b) Use of the redundant portion of the existing subordinate control center computer system to perform the BUCC functions. In this configuration, special backup software that is normally deactivated can be initialized on the redundant processor of the existing system whenever there is a need for the BUCC. If there is an extended outage of the primary control center, this configuration can provide an interim solution that will allow sufficient time to procure additional hardware to implement the BUCC functions on a separate system and, if necessary, expand the overall functionality of the BUCC.

5.2.3 Other Alternatives

Many utilities, regardless of their prototype categories, include a development system or a stand-alone operator training simulator in their EMS/SCADA system configuration. Each of these systems can be a potential BUCC if located at a remote site. The only resources they lack are sufficient communication interfaces to remote facilities for performing the required monitoring and control actions. For an incremental investment either of these systems can be expanded to include the necessary communications interface equipment.

Another alternative is the use of a high performance workstation that is normally used as a remote console. Under emergency conditions, the workstation can be reconfigured and enhanced with SCADA and AGC capabilities to perform a minimum set of BUCC functions, assuming sufficient data and voice communication access to critical remote facilities is available.
6. Training and Maintenance Costs

In addition to any leased communication costs, there are two main elements to the recurring cost of a backup control center; training and maintenance.

6.1 Training Costs

Training will consist of classroom training in the procedures to evacuate the primary control center, activate and occupy the BUCC, operate from the BUCC, and validate and reactivate the primary control center once the emergency condition has cleared. The amount of required training will increase in proportion to the degree the tools and procedures used in the BUCC are different than those used in the primary control center.

In general, if time is already allocated for an ongoing operator training program, the BUCC training should have a relatively small incremental cost associated with it. Otherwise, it will be necessary to bring operators in for training at special times and may involve overtime costs, as well as the cost for developing the training materials.

In addition to classroom training, there is the need for periodic drills to practice transfer procedures from the primary to the backup control center. Since most utilities staff both the primary and backup control centers during drills, the cost will be the overtime costs for a second shift of operators. These drills are normally conducted at a periodicity that ranges from quarterly to yearly. The duration of the drills normally range from an hour to a maximum of 24 hours.

6.2 Maintenance Costs

Three aspects of BUCC maintenance are hardware, software, and database/display updates. The degree of difficulty of all three areas is related to the configuration of the BUCC compared with that of the primary control center.

Even if the BUCC is based on entirely manual operations, (i.e., does not have any computers or other control equipment), there will still be some maintenance cost. This cost will be to maintain adequate communication circuits, written evacuation and startup procedures, log sheets, system diagrams, substation diagrams, relaying diagrams, operating procedures, and other textual material normally stored in a computer system.

If the BUCC is an exact duplicate or a subset of the primary control center, the incremental maintenance costs associated with the BUCC should be relatively small. Depending on whether the utility performs self-maintenance or contracts out hardware maintenance, the incremental hardware maintenance cost will either be negligible or a function of the additional hardware to be maintained. The software, database, and display maintenance can be accomplished as part of the primary control center maintenance and simply involves transporting the changes to the BUCC site and loading them into the BUCC. This can also be accomplished via a data link if the two centers are interconnected.

If the BUCC is the functional equivalent of the primary control center, but uses different hardware and software, such as the system previously used at the primary control center, all three elements of the maintenance costs will escalate and may approach those of the primary control center. The hardware maintenance will require unique training, test equipment, and spare parts. All software
changes and database and display edits performed at the primary control center will have to be repeated at the BUCC.

In addition to the above cases, there are various configuration alternatives that impact the maintenance costs. For example, the use of a BUCC with reduced functionality that is configured with PCs and workstations rather than minicomputers will reduce both hardware and overall system maintenance costs. Maintenance also depends on whether the BUCC has any other functions when the primary control center is operational. If the BUCC is normally used for other purposes, the incremental maintenance cost for its use as a BUCC will be very small. Similarly, if the BUCC is co-located with an existing control system that requires an on-site maintenance staff, the cost of BUCC maintenance will be reduced significantly.

In addition to the BUCC maintenance costs, a utility should also consider an annual budget for software upgrades both to enhance economic operation and overall power system security and to maintain a level of “open system” standards that are compatible with those implemented on the primary control system. This level of compatibility will allow both systems to evolve together as the responsibilities and interface requirements for the control center change over time.

7. Conclusion

The following conclusions regarding the planning of a backup facility were drawn from the survey of utilities with existing BUCCs:

(1) The most critical issue, based on both initial and recurring costs, in implementing a backup control center is its access to both voice and data communication facilities. It is for this reason that the majority of backup control centers are currently located at regional control centers or other utility locations that have access to a company-wide communications network. Installing the BUCC at a regional control center also has the advantage of an on-site maintenance staff and already existing support facilities for an on-line control system. For those utilities without regional control centers, a remote facility that houses an operator training simulator, a software development system, or a high-performance workstation may be a good candidate for a BUCC if sufficient communication facilities are available.

(2) Most backup control systems are implemented as an opportunistic addition to a larger procurement, such as a replacement EMS or a regional SCADA system. However, utilities that do not have a BUCC can use advances in communications networking and control system platforms to reduce its cost for implementing a BUCC. Microprocessor-based technologies, the industry-wide migration to de facto software standards (e.g., UNIX, TCP/IP, SQL) and high-level languages, and the ability to network diverse computer systems have driven down both the hardware and software costs for implementing a backup control system while improving the available processing power for a reduced function backup facility.
(3) The scope of the BUCC should not only satisfy the minimum requirements as described in Section 2, but should also have sufficient functionality to cover most long-term disasters. On average, backup control systems have been designed to support emergency operations for up to a six-month period. For severe control center outages that extend beyond the six-month period, the six months will allow sufficient time to enhance the backup control system into a redundant, fully functional primary control system.
Appendix A

Bibliography


Appendix B

Utility Questionnaire

Introduction

This survey is being conducted by Macro Corporation under the sponsorship of the NERC Operating Reliability Subcommittee and EPRI within the framework of EPRI Project RP2473-68. The survey responses will be used in the study collectively and no reference will be made to the name of the organization nor the source of specific information. However, a list of the organizations responding to the questionnaire will be included in the study report. If you do not wish the name of your organization to appear in the list, please check the box below.

☐ Do not use the organization name in the report.

Objectives

The objective of the study is to prepare a reference document for utility use in scoping, justifying, and planning a backup control center.

The objective of this survey is to obtain sufficient information about current knowledge of and experience with backup control center planning and implementation. This information will be used to define general control center prototypes based on operational responsibility and specific planning elements to be incorporated into the reference document.

Method Of Response

After you have had time to review the survey you will be contacted by Macro to arrange a telephone interview during which we will receive your responses verbally. If you prefer, you may respond in writing and we will call you only if we require further clarification of your answer.

1. Organization Data

1.1 Organization Name

1.2 Discuss Your Operating Responsibilities

   a. Involved in generation control
   b. Calculates ACE
   c. Receives generation control signals from higher level control center
   d. Sends signals to units
   e. Sends signals to lower level control center

1.3 Control Center Location
2. Control System Data

2.1 SCADA or EMS
2.2 Manufacturer and Installation Date
2.3 Functions
   Consider the following:
   a. SCADA — RTUs (#)
      — Data Links (#)
   b. Automatic Dispatching System (AGC, ED, ITS, RM, and PC)
   c. Generation Scheduling (LF, UC, and ITE)
   d. Power System Analysis (SE, BLDF, SSSA, PF, VS, SCD, and SENH)
   e. Information Storage and Retrieval (PDSR, Energy ACC, and DDC)
   f. Other — Specify

2.4 User Interface
   a. Consoles — Local
      — Remote
   b. Mapboard
   c. Trend Recorders
   d. Other — Specify

3. Backup Control Center

3.1 Do you have a plan to continue operation in the event the control center becomes inoperable?
   YES — Go to 3.4   NO — Continue

3.2 Explain the lack of a plan. Was it a conscious decision or default? Is there a plan to reconsider?

3.3 If it was a conscious decision, explain the basis for the decision.

3.4 Do you have a Backup Control Center (BUCC)?
   YES — Go to 3.7   NO — Continue

3.5 Have you ever considered implementing a BUCC? Please explain why you have not considered one or why you decided against one.

3.6 Have you ever been in a situation where you would have used a BUCC if you had one? Please elaborate.

3.7 Did you perform a requirements or justification study before implementing the BUCC? If yes, please summarize the study and its results.

3.8 Discuss the types of emergencies that would force you to use a BUCC. What are the minimum and maximum durations you would expect to occupy the BUCC due to any single emergency or disaster? Discuss the range of backup plans you may have based on the severity of the incident.
3.9 What was the justification for the BUCC? Consider economic, political, emotional, results of a management audit, or other.

3.10 Were the costs and benefits quantified? If so, please discuss the methods used to quantify both.

3.11 What range of outage durations of the main control center was the BUCC designed to support? Consider:
   a. Short Term — Up to 48 hours
   b. Intermediate Term — Up to two weeks
   c. Long Term — Over two weeks

What plans do you have if the outage exceeds the planned duration?

3.12 Where is the BUCC located with respect to the main control center? Are the BUCC site and facilities used for any other purpose when the BUCC is not in use? If yes, please elaborate.

3.13 What facilities are provided at the BUCC? Consider the following:
   a. Computers — Host Minicomputers, workstation(s), PC(s), calculators, and analog equipment
   b. Consoles — Local and/or remote
   c. Mapboard, trend recorders, etc.
   d. Local meters
   e. Maps, one-line diagrams, log sheets, operating instructions, system documentation, and the like

3.14 What communications are available at the BUCC? Consider the following:
   a. Data from RTUs? Data links? Other?
   b. Dedicated voice channels to power plants, other control centers, other company facilities, and other places.
   c. Dial-up voice channels
   d. Radio channels

3.15 What functions are available at the BUCC? For each function performed at the main control center, estimate the percent that is available at the BUCC? (For example x% of the RTU data available at the main control center is available at the BUCC.)

3.16 For those functions not available at the BUCC, how are they performed when the main control center is down? For example, the transmission coordination and monitoring functions that are normally performed at the main control center are parcelled out to the divisional control centers when the main control center is down.
3.17 Discuss the method used to procure the BUCC. Was it implemented as a standalone project or as part of another project? Provide an estimate of the cost of the BUCC including procurement cost, project staffing, communications, training, facilities, and all other related costs.

3.18 Do you have written procedures for the following events?

a. Evacuation of the main control center
b. Occupation and activation of the BUCC
c. Functional verification and reactivation of the main control center

3.19 Do you perform system drills periodically where the BUCC is activated and used to control the electric power system? What is the frequency and duration of these drills?

3.20 Have you ever activated and used the BUCC because of a real problem at the main control center? If yes, please elaborate.

3.21 Discuss the impact of the BUCC on the following:

a. Staffing
b. Training
c. Documentation
d. Hardware Maintenance
e. Database and Software upgrades
f. Operation and Maintenance Budget

3.22 Discuss future plans for a BUCC or upgrading the existing BUCC.
Demand-Side Management

The System Operator’s Perspective

A Reference Document

by the

North American Electric Reliability Council

Interconnected Operations Subcommittee
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The System Operator’s Perspective

I. Introduction

Demand-Side Management (DSM) is a rapidly growing portion of utility capacity resources. Traditionally, the utility’s integrated resources planner views DSM as a resource to shave the utility’s annual peak demand. On the other hand, the system operator sees DSM as a tool of last resort to be used sparingly in a capacity emergency. This view of DSM is changing.

Demand-Side Management now has the prospect of becoming a more widely used resource in the routine operation of an electric power system. Within certain limits, the system operator can use DSM as though it were a generation source for both real and reactive power.

Resourceful system operators, working in conjunction with customer accounts representatives and rate design personnel, are designing direct DSM options for selected customers to cover a wide range of operating situations. Direct DSM can provide utilities new ways to provide for operating reserve, system control, and load following. This is in addition to DSM’s classical use during system emergencies. Direct DSM can provide customers with lower energy costs by allowing the utility to control when electricity is used.

This document explains the operational aspects of direct DSM, its flexibility, and its limits.
II. Glossary

**Load** and **Demand**. People often use load and demand synonymously. In this document, load generally refers to a device, or even a customer, that receives power from the electric system. Toasters, arc furnaces, and wholesale customers, are all loads. The measure of the power that the load receives or requires is the demand. Demand can be measured (usually in MW), whereas load cannot — it can only be counted. This document tries to keep these definitions of load and demand in mind, but there are ‘gray areas’ where either term could arguably be used. In fact, some people refer to “load management” instead of “demand-side management.”

**Demand-Side Management (DSM).** For the purpose of this document, DSM is defined as the deliberate alteration of electrical energy use by either indirect or direct means. This control is on the “demand” side of the electric system instead of the “supply” side.

**Indirect DSM.** The wide range of passive conservation measures, such as building insulation and energy efficient lighting, motors, and heat pumps, to name a few. The goal of indirect DSM is to alter the way electricity is used permanently and continuously. The role of indirect DSM is not the topic of this document.

**Direct DSM.** An active “load management” tool for the system operator and is the focus of this document. Operator control is the common element of direct DSM programs such as appliance control, interruptible customer loads, and limited voltage reduction. When a customer agrees with the utility to participate in direct DSM, the customer relinquishes to the utility the customer’s control of an agreed-to portion of its demand as governed by various utility incentive rate structures.
III. Purpose of this Document

This document serves four roles:

1. Help the systems operator understand demand-side management and how DSM can be used as an operating tool.
2. Provide information about DSM use to utility personnel who market DSM programs, and those who set customer incentive rates for participating in DSM programs.
3. Furnish the utility planner with insight into how the DSM programs can be used in system operations.
4. Provide the NERC Operating Committee with a reference for developing Operating Policies on DSM use.

This document is designed to address many operating applications of direct DSM. A discussion of the reliability and control aspects of each use is the primary focus.

IV. Operator’s DSM “Menu”

DSM Category Test

This section of the report deals specifically with a “menu” of many categories of direct DSM available to the system operator for use during both normal and emergency conditions. In evaluating the requirements and applicability of direct DSM in each category, a series of conditional tests can be applied to define the appropriateness of the DSM application to meet the needs of the menu items.

The following conditions comprise the test:

1. Is DSM under operator control?
2. Is DSM armed at all times?
3. Is DSM under push button (supervisory) control?
4. Is a phone call required to activate the DSM?
5. Is advance notice required to activate?
6. If yes to (5), how much time is required to activate?
7. What is the length of time from activation of the DSM until complete load control is achieved?
8. Is DSM temperature sensitive?
9. Is DSM demand sensitive?

10. Can the customer override the activation of DSM?

11. Is there a limit on the number of times a day or week or year DSM can be activated? Is there a limit (practical or contractual) on the duration of the DSM control cycle during a day?

12. Does the utility know in real time how much demand reduction can be achieved by DSM activation? How is this information gathered?

13. Does the system operator have authority to activate DSM without further approval?

Appendix A contains a matrix ordered by question and operator menu selection with suggested compliance requirements for each.

**Reserve Categories**

**General**

Each control area or group of control areas maintains operating reserve as specified in its Region’s operating guides. This reserve provides for such factors as errors in forecasting, equipment unavailability, number and size of generating units, forced outage rates, maintenance schedules, regulating needs, and load diversity. The operating guides further specify allocation of reserves among Region members, mix of spinning and non-spinning reserve, and procedures for applying reserves. DSM can qualify for various categories of operating reserve depending upon the timing of activation, the level of direct control, and the level of automation.

**Responsive Reserve**

Responsive reserve, as applied to DSM, is equivalent to synchronized reserve as applied to a generating unit. However, to be functionally equivalent, the DSM be activated automatically within the time frame of a generating unit’s governor response. Responsive reserve automatically responds to a substantial frequency deviation (i.e., a frequency deviation caused by a significant loss of generation or load) and arrests the frequency decline (or frequency rise).

Generally, direct DSM that qualifies for responsive reserve includes contract interruptible load connected to high-set underfrequency relays (those that operate at a frequency higher than relays set to disconnect firm customer loads) or activated by an area control error (ACE) deficiency. Such DSM can qualify as responsive reserve provided that the following conditions are met:

1. It is interrupted within 20 cycles following:

   1.1 A decay in system frequency (Hz), or negative ACE deviation (MW), to a predetermined level, or

   1.2 A rate of frequency decay (Hz/second) greater than a pre-determined rate, or

   1.3 An instantaneous frequency step change (mHz) greater than a designated magnitude. (For example, ERCOT targets 59.7 Hz as a designated frequency, which is a 300 mHz step change.)
2. The response is automatic.

3. A real-time signal of total interruptible load (MW) on high-set underfrequency relays is telemetered to the control center.

4. The load will remain interrupted until it is replaced by other generation resources.

5. The load will only be restored with the approval of the system operator.
Operating (Ten-Minute) Reserve

Only that capacity that can be made available and fully applied within ten minutes and is under the system operator’s control may be considered as ten-minute reserve. Many appliance control programs require six to eight minutes to activate and are under direct supervisory (push-button) control of the system operator. These DSM programs qualify in this reserve category. Direct DSM measures that require advance (greater than ten minutes) notification to affected customers to reduce their demand do not qualify in this category.

If not carefully used, appliance control programs can cause a loss of load diversity. The longer certain appliances have been turned off, the restrike (or cold-load pick-up) imposed on the electric system once they have been turned back on may well exceed the initial demand reduction by 1 1/2 to 2 times. This restrike is an important consideration when deciding the use and timing of appliance control for operating reserve.

Measurement and verification is another important consideration, because it is unlikely that thousands of appliances will be telemetered directly to the control center.

When applying direct DSM as operating reserve, the following conditions must be met.

1. The system operator must have authority to use the DSM without further approval.

2. Reliable communications (equivalent to that used with generating resources) must be in place to ensure that the system operator can quickly activate the DSM equipment or notify the person that causes the load relief to occur. Communication paths should be direct and, if necessary, redundant.

3. Load relief must be sustained for as long as it takes to replace the DSM operating reserve with alternate resources. Typically, DSM load relief that lasts for less than thirty minutes should not be recognized as operating reserve.

4. Conservative estimates of load relief must be used to avoid over-subscribing the DSM resource. Calculation of the load relief of the direct DSM resource must consider the time of day and day of week, season, temperature, amount of sunlight, customer activities, etc., at the time the DSM is to be activated.

5. The load relief must be immediately apparent to the system operator. Programs involving appliance control or voltage reduction where direct metering and verification is not possible must be carefully reviewed for application as operating reserve. Verification procedures should be implemented as necessary to overcome the uncertainty of load forecasting.

Backing Up Non-firm Purchases

DSM resources can be used to allow a utility to back up a non-firm energy purchase to supply the load in lieu of activating direct DSM to curtail load. In other words, direct DSM not interrupted can be used as spinning reserve to back up the purchasing utility’s non-firm purchases of the same magnitude. In general, to qualify in this category, the direct DSM program must have the same basic requirements as direct DSM that qualifies for operating (ten-minute) reserve. Obviously, the same qualifications in terms
of verification and forecasting would apply to this application. Dual-fuel heating devices are particularly good DSM resources for this type of application.
Peak Shaving

General
Peak shaving, sometimes called peak clipping, refers to the use of DSM by the system operator to reduce demand at the time of the daily peak. Peak shaving DSM can be implemented for either economic or emergency reasons.

Economy Peak Shaving
From the economic standpoint, DSM can reduce a utility’s long-term cost of service by deferring the need for future capacity additions. In the short-term, it can lower the system’s daily demand, which in turn reduces the utility’s immediate need to generate with its most expensive capacity or procure expensive purchased power. In this case, the operator determines that the lost revenues from the reduced electricity sales while the DSM is active are less than the cost to serve the demand had it not been “shaved.” Pre-established cost levels help the system operator make the decision to use DSM in this situation. This use of DSM may also affect unit commitment and operating reserve determinations as well as other real-time dispatch decisions.

A few of the more common economic-based uses of peak shaving DSM include:

1. Reduction of annual or seasonal peak demands to limit the need for additional or new installed resources, including transmission and distribution facilities.
2. Reduction of daily or weekly peak demands to limit the need to operate more costly and less efficient resources.
3. Reduction of daily or weekly peak demands to enable other restricted energy resources to fit under the daily or weekly system demand curve (shape).
4. Alteration of the daily demand shape to better utilize (optimize) the mix of other available resources, including hydro resources, peaking resources, and any other limited energy resources.

When considering the use of DSM solely for economic purposes, several issues should be resolved to ensure the cost effectiveness of the program:

1. Communications – What is required? Is redundancy necessary? Who contacts the customer?
2. Implementation – Who determines the economic parameters that might trigger DSM activation? How many times is the use of DSM authorized per year or month or week or day? How often will DSM be used to prevent other resources from being started? How can the use of DSM be optimized and fit into the unit commitment and scheduling
process? How little advance notice from time of request to achievement of load relief is tolerable? Once notified, how long does it take for the customer to actually provide the load relief? What happens if the customer does not curtail the load?

3. Telemetering – What metering is required at the dispatch center to ensure the availability of adequate DSM operating information? Megawatts? Megawatthours?

4. Economic Data – Economic use of DSM requires some controls to ensure that the decisions to initiate curtailment is the proper economic choice. Like any restricted resource, the DSM resource should be used when it provides the most economic benefit. Load not served is revenue not generated. Such factors should be carefully evaluated against the alternatives if proper economic choices are to be selected. What economic information should be available to the System Operator? Cost to serve the load? Savings if load not served? How are costs and savings determined? How are they presented to the System Operator?

5. Verification and Reports – Verification of the amount of actual load curtailed is essential. How does this verification happen? How is the data audited? By whom? How does the load not served get factored into historical data?

Emergency Peak Shaving

In emergency situations, peak shaving may be utilized to maintain the reliability of the utility’s system or ensure continued service to customer load with a higher level of firmness. DSM implementation during emergencies is generally governed by capacity or reserve levels existing at the time, rather than economics.

The primary use of DSM during emergencies is to reduce the total demand, and could affect operating reserve obligations. Implementation can be prioritized and implemented as an action to:

1. Reduce actual system demand during system-wide capacity deficiencies.
2. Reduce actual system demand within a defined transmission area during times when transmission might be otherwise unduly stressed.
3. Reduce reactive requirements to improve a local or widespread low-voltage condition.
4. Provide assistance during periods of short-term capacity deficiencies in other interconnected systems.

In addition to the considerations that need to be evaluated when using DSM for economic purposes, there are other considerations that need to be evaluated when using DSM as an emergency demand relief resource. These other considerations include, but are not limited to:

1. What is the priority of implementing emergency procedures? Is the DSM used before committing available alternate resources? After utilizing all other available resources? Before or after purchasing emergency assistance from neighboring interconnected systems?
2. Is there a practical limit to the percentage of total resources that DSM should comprise? Does DSM impact the amount of and number of times that a Control Area needs to rely on the Interconnection? If DSM is used only after emergency purchases or in lieu of starting other resources, how does the amount of DSM impact the number of times that a Control Area must rely on the Interconnection to meet its load and operating reserve obligations?
3. How is DSM used in near-term operations planning? Does one plan an emergency?

4. Mutual assistance arrangements. DSM, if not used carefully, clearly reduces the ability of one system to help another. If one control area uses DSM before starting all other available resources and a neighbor needs help, will DSM remain activated to make other resources available?

Activation

Peak shaving is generally accomplished either by direct system operator control of customer equipment or by indirect control where the customer controls usage and demand at the request of the system operator. With direct operator control, a communications system between the utility and the customer transmits control instructions to a receiver and control actuator on the customer’s premises. With indirect operator control, the utility notifies the customer by telephone, teletype, or other means of communication, and asks the customer to reduce demand within contractual limits for specified periods. With indirect control the utility relies on rate incentives or contract penalties or both to encourage the customer to reduce electricity usage during peak demand periods. In both direct and indirect control, the utility and the customer must agree to designate the load being controlled, define the hours of control, and identify the conditions under which load control will be implemented.

Predictability

Water heaters, air conditioners, and heat pumps are typical loads that can be controlled for peak shaving purposes in the residential and commercial sectors. Certain industrial processes that can be cycled or interrupted on short notice also lend themselves to peak shaving applications. However, in any application, the predictability of load available to be reduced is paramount. Load subject to peak shaving may vary significantly by hour, week, or season, and is influenced by customer habits, weather, and economic conditions. Monitoring equipment to provide system operators with accurate estimates of available load shaving demand may be cost effective for large interruptible loads, but would undoubtedly be uneconomical for residential or commercial applications. Residential and commercial applications will require significant analysis of historical usage patterns and customer attitudes to develop a reliable track record for forecasting available load shaving capabilities during periods it will likely be used.

The expected demand reduction from the load under contract for a utility’s peak shaving option is subject to numerous variables including the frequency of use, temperature and economic conditions. Under direct operator control, the utility should be reasonably assured that when the demand shaving DSM program is activated an expected amount of load will be curtailed. Similarly, the utility should expect an industrial customer with interruptible load to curtail load when called upon to do so. The utility cannot depend on the customers remaining under contract for DSM peak shaving if one or more of the following occur:

1. The customer’s expectations regarding how often its load will be curtailed are regularly exceeded.

2. Hot or cold temperatures resulting from cycling of air conditioners or heat pumps causes the customer discomfort.

3. Economic conditions make the price of firm capacity more practical for the customer.

To assure buy-in of peak shaving options and keep sufficient contracts in force for an effective program, it will be necessary for utilities to provide attractive incentives for customers who remain committed to demand-side options and expensive penalties for those who drop out.
Effects on Load

Estimates must also take into account how peak shaving will affect the demand being reduced.

For example, in a typical residential or commercial peak shaving application, a group of air conditioners is prevented from operating for a portion of each half-hour period and a companion group is prevented from operating for a portion of the following half-hour period. Because cycling between groups may occur when some air conditioning units are off as part of their natural duty cycle, the initial demand reduction may be significantly less than anticipated. Furthermore, as implementation time elapses, the units will tend to operate more during unrestricted periods to catch up to the customer’s needs. Consequently, the net reduction in demand will diminish with time and could become negligible. In this situation, maximum peak shaving would only occur if it were implemented when air conditioning load is saturated (all units running continuously).

Restoration

Restoration of load curtailed under peak shaving options is generally accomplished in the same manner as implementation. Care must be taken to ensure that the total addition of load to the system, similar to “cold load pickup” is not unexpected and can be readily supplied with available capacity. (i.e., More load may be picked up than was initially curtailed.)

Valley Filling

General

One particularly interesting type of DSM is that type used to fill the valley demand period. This category of DSM is opposite of peak shaving, and is attractive to utilities that have a large amount of base load generation with relatively low “valley” demand periods. This combination makes it desirable to “move” demand from the peak demand period, perhaps by peak shaving, to the off-peak demand period when production costs are lower. Savings resulting from not having to cycle large fossil-fired units or having to reduce the output of nuclear units, can be significant. These savings can be passed on to the utility customers through special rates to encourage energy use away from the daily peak demand period and toward the valley period. Coupled with the revenues resulting from these increased energy sales, this use of direct DSM can be an attractive option — for both the utility and its customers.
Variable Energy Rates
Today, many utilities are beginning to offer industrial customers energy at variable rates. Some utilities are even offering industrial customers incremental energy rates for electricity used beyond a firm demand during periods when capacity to serve this load is readily available. There are many industries today that can increase their electrical demand by computer control when rates are lower. Partial requirements customers may reduce their own generation if the price of available energy is less than their cost. When system conditions are such that 1) minimum generation problems are anticipated, 2) electricity is available at an incremental rate less than the standard filed rate, or 3) capacity is readily available to serve additional load, the system operator may offer these customers this special energy rate to fill the demand valley.

Utilities use a host of methods to communicate this energy offering to their customers. Computer-to-computer links that can inform customers of the energy price hourly, daily, or for several days are currently being used.

Improving a utility’s load factor\(^1\), decreasing generating unit cycling, and sharing these savings with their industrial customers can make this a very popular type of DSM tool.

\(^1\)Load factor is the ratio of the utility’s average demand to its peak demand, usually expressed as a percent.
V. Operations Planning

Direct DSM is a limited energy resource within the constraints of price elasticity or contractual agreements. Activation of direct DSM may be limited by regulatory mandate, by contract, by the economics of the rate structure, or by the risk of customers’ tolerance of frequent interruption. Direct DSM is among a growing inventory of limited energy options available to the system operator. This inventory also includes limited storage hydroelectric facilities, interruptible fuel contracts, partial requirements customers, interruptible interchange arrangements, as well as the potential for limited emissions allowances and other such environmental restrictions.

The traditional function of operations planning is to forecast the system demand and commit the lowest cost generation mix while maintaining an adequate reliability profile for the system. Direct DSM adds several dimensions to this traditional view:

Forecasting DSM Capability

The first added dimension is the operator’s ability to forecast the capability of the various DSM programs for the ensuing operating period. The weather sensitivity of DSM is a source of forecast uncertainty. Some industrial and commercial interruptible contracts require advance notice of the time and duration of the interruption, without which the interruption cannot occur. Measurement and verification become critical factors to apply to the forecast algorithms.

Economic Forecasting

The second dimension is the economic forecast. More and more customers are becoming partial requirements customers driven by daily economic conditions. In addition, the utility rate structure may suggest that beyond certain cost thresholds, some DSM customers should be interrupted. Economic analysis, therefore, requires a new skill and tool set to evaluate the cost and price signals to forecast and activate DSM.

System Dynamics

The third dimension is the dynamics of shedding and restoring large quantities of load on the transmission and distribution system. Modeling these dynamics becomes a critical factor for planning reliable operation. Voltage swing requirements for busses that have a heavy inductive load shed can become a serious reliability consideration when that load is restored, particularly if sufficient time has passed for diversity of thermostatic controls to diminish and thus increase the load that was shed.
VI. Issues

The primary purpose of this document is to examine the operating issues that result from the application of DSM. The following are potential categories for which operating instructions could be appropriate:

Qualifications

The basic categories that would qualify DSM for the various uses within the operator’s menu are discussed in Chapter II and in Appendix A. The primary qualifications are:

1. Level of control
   1.1 automatic
   1.2 operator directed
   1.3 customer directed

2. Timing
   2.1 notification requirement
   2.2 arming requirement
   2.3 time to implement
   2.4 time to achieve full effectiveness

3. Authorization
   3.1 operator authorized to use at discretion
   3.2 operator needs to seek approvals

4. Frequency of use/duration limitations

Telemetry and Measurement

Ideally, a direct DSM application has its demand telemetered directly to the control center. In this arrangement, the operator is continuously aware of the exact amount of demand relief available when the DSM is activated. DSM that is not telemetered (e.g., appliance controls, voltage reductions, etc.) introduces an element of uncertainty that must be effectively addressed. The strictest interpretation would only allow DSM that is directly controlled and telemetered to qualify as operating reserves. Other interpretations would permit non-telemetered DSM to qualify provided that a thorough history of the effectiveness of such programs is developed and applied in the forecasting.

Verification

Careful records should be maintained to demonstrate the effectiveness of each DSM program. New programs should be carefully reviewed in the engineering environment before being released to the operator as a routine operating tool. New programs should be phased in slowly with initially very conservative estimates of effectiveness that can be relaxed as data, analysis, and experience dictates.
**Forecasting**

Just as the hourly demand is variable, so to is the value of DSM programs. Weather, time of day, day of week, season of year, and other parameters such as frequency of use, affect the effectiveness of DSM programs. The daily operations planning function should include a careful review and analysis of each program as it applies to the operator’s menu. Thermostatically controlled DSM resources, for example, result in varying degrees of diversity that impact their effectiveness at various temperature and humidity levels and, hence, at various system demand levels. Such variability should be known to the system operator and incorporated into the forecast just as ambient air temperature, cooling water or hydraulic head factor into hourly operating capacities for traditional generation resources. Shifts and manufacturing cycles introduce variability into industrial and commercial interruptibles.

**Restoration**

Restrike or cold load pickup is an important consideration for using direct DSM, particularly for those applications that are thermostatically controlled or have other diversity measures such as certain industrial processes. The restored load can easily double the interrupted load depending upon weather conditions or time interrupted, or both. The operator should be fully aware of these effects before using these kinds of DSM programs and be provided with good estimates of restrike effects.

DSM used to control a transmission contingency is especially susceptible to the reliability impacts of restrike. If DSM load was shed to control a thermal, voltage, or stability limit for a transmission contingency, the operator must be aware of the nature of the load (i.e., resistive or inductive) as well as the amount. For example, the system operator must consider the reliability effects of reenergizing a primarily inductive load that is twice as large as what was interrupted during a voltage constrained contingency. Operating instructions should be available to the operator for such applications.

**Communications**

A rule of thumb is that communications for DSM should be equivalent to that required for a generation resource used for a similar application. Communication paths should be readily available, direct, and, if necessary, redundant. When phone calls are required, all parties involved should clearly understand their roles and have provisions for backup for personnel and equipment.

**Sustainability**

Frequency and duration of use impact the sustainability of a DSM program. Programs should be carefully analyzed to determine the thresholds beyond which frequency of use or duration would diminish their effectiveness. Programs whose effectiveness cannot be sustained beyond thirty minutes, for example, should be carefully reviewed for qualification in reserve categories. Programs whose effectiveness cannot be sustained beyond an hour or two should be carefully reviewed for peak-shaving uses. Contractual arrangements regarding frequency of use and duration should have input from the system operator. Specifications for minimum acceptable levels for frequency of use and duration should be established by system operating departments. Mechanisms to track frequency of use and duration should be integrated into the operating routine. These statistics, which are critical for making informed decisions about the DSM program, should be readily available to the system operator and the operations planner.