NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

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

Functional Model Working Group+ Meeting

Thursday, April 7, 2005 — 8 a.m.–5 p.m.
Friday, April 8, 2005 — 8 a.m.–noon

Sheraton Gunter San Antonio
205 E. Houston Street
San Antonio, TX 78205
Phone: 210-227-3241 – Fax: 210-227-9305

Agenda

1. **Administrative**
   a. Arrangements
   b. Procedures
   c. Introductions
2. **Meeting Objectives**
3. **Document Review**
4. **Functional Model Concepts**
5. **Regional Reliability Plans**
6. **Recommendation List and Action Plan**
7. **Timeline and Deliverables**
8. **Define Near-Term Tasks, Next Meeting Agenda, and Work on Recommendations**

Item 1. Administration

a. Arrangements

The secretary will review the meeting arrangements. The meeting begins on Thursday, April 7 at 8 a.m. and will adjourn on Friday, April 8 at noon. Working Group Chairman Jim Cyrulewski will preside.

b. Procedures

The NERC Antitrust Compliance Guidelines and a summary of Parliamentary Procedures are attached for reference. The secretary will answer questions regarding these procedures.

Attachments

- Antitrust Guidelines
- Parliamentary Procedures

c. Introductions

Those attending will introduce themselves. The working group roster is attached.

Attachment

FMWG+ Roster

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

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

NERC ANTITRUST COMPLIANCE GUIDELINES

I. GENERAL

It is NERC's policy and practice to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition. This policy requires the avoidance of any conduct that violates, or which might appear to violate, the antitrust laws. Among other things, the antitrust laws forbid any agreement between or among competitors regarding prices, availability of service, product design, terms of sale, division of markets, allocation of customers or any other activity that unreasonably restrains competition.

It is the responsibility of every NERC participant and employee who may in any way affect NERC's compliance with the antitrust laws to carry out this commitment.

Antitrust laws are complex and subject to court interpretation that can vary over time and from one court to another. The purpose of these guidelines is to alert NERC participants and employees to potential antitrust problems and to set forth policies to be followed with respect to activities that may involve antitrust considerations. In some instances, the NERC policy contained in these guidelines is stricter than the applicable antitrust laws. Any NERC participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NERC's antitrust compliance policy is implicated in any situation should consult NERC's General Counsel immediately.

II. PROHIBITED ACTIVITIES

Participants in NERC activities (including those of its committees and subgroups) should refrain from the following when acting in their capacity as participants in NERC activities (e.g., at NERC meetings, conference calls and in informal discussions):

- Discussions involving pricing information, especially margin (profit) and internal cost information and participants' expectations as to their future prices or internal costs.
- Discussions of a participant's marketing strategies.
- Discussions regarding how customers and geographical areas are to be divided among competitors.
- Discussions concerning the exclusion of competitors from markets.
- Discussions concerning boycotting or group refusals to deal with competitors, vendors or suppliers.

Approved by NERC Board of Trustees
June 14, 2002

III. ACTIVITIES THAT ARE PERMITTED

From time to time decisions or actions of NERC (including those of its committees and subgroups) may have a negative impact on particular entities and thus in that sense adversely impact competition. Decisions and actions by NERC (including its committees and subgroups) should only be undertaken for the purpose of promoting and maintaining the reliability and adequacy of the bulk power system. If you do not have a legitimate purpose consistent with this objective for discussing a matter, please refrain from discussing the matter during NERC meetings and in other NERC-related communications.

You should also ensure that NERC procedures, including those set forth in NERC's Certificate of Incorporation and Bylaws are followed in conducting NERC business. Other NERC procedures that may be applicable to a particular NERC activity include the following:

- Organization Standards Process Manual
- Transitional Process for Revising Existing NERC Operating Policies and Planning Standards
- Organization and Procedures Manual for the NERC Standing Committees
- System Operator Certification Program

In addition, all discussions in NERC meetings and other NERC-related communications should be within the scope of mandate for or assignment to the particular NERC committee or subgroup, as well as within the scope of the published agenda for the meeting.

No decisions should be made nor any actions taken in NERC activities for the purpose of giving an industry participant or group of participants a competitive advantage over other participants. In particular, decisions with respect to setting, revising, or assessing compliance with NERC reliability standards should not be influenced by anti-competitive motivations.

Subject to the foregoing restrictions, participants in NERC activities may discuss:

- Reliability matters relating to the bulk power system, including operation and planning matters such as establishing or revising reliability standards, special operating procedures, operating transfer capabilities, and plans for new facilities.

- Matters relating to the impact of reliability standards for the bulk power system on electricity markets, and the impact of electricity market operations on the reliability of the bulk power system.

- Proposed filings or other communications with state or federal regulatory authorities or other governmental entities.

- Matters relating to the internal governance, management and operation of NERC, such as nominations for vacant committee positions, budgeting and assessments, and employment matters; and procedural matters such as planning and scheduling meetings.

Any other matters that do not clearly fall within these guidelines should be reviewed with NERC's General Counsel before being discussed.

Parliamentary Procedures

Based on Robert's Rules of Order, Newly Revised, 10th Edition, plus "Organization and Procedures Manual for the NERC Standing Committees"

Motions

Unless noted otherwise, all procedures require a "second" to enable discussion.

When you want to…	Procedure	Debatable	Comments
Raise an issue for discussion	Move	Yes	The main action that begins a debate.
Revise a Motion currently under discussion	Amend	Yes	Takes precedence over discussion of main motion. Motions to amend an amendment are allowed, but not any further. The amendment must be germane to the main motion, and can not reverse the intent of the main motion.
Reconsider a Motion already approved	Reconsider	Yes	Allowed only by member who voted on the prevailing side of the original motion.
End debate	Call for the Question *or* End Debate	Yes	If the Chair senses that the committee is ready to vote, he may say "if there are no objections, we will now vote on the Motion." Otherwise, this motion is debatable and subject to 2/3 majority approval.
Record each member's vote on a Motion	Request a Roll Call Vote	No	Takes precedence over main motion. No debate allowed, but the members must approve by 2/3 majority.
Postpone discussion until later in the meeting	Lay on the Table	Yes	Takes precedence over main motion. Used only to postpone discussion until later in the meeting.
Postpone discussion until a future date	Postpone until	Yes	Takes precedence over main motion. Debatable only regarding the date (and time) at which to bring the Motion back for further discussion.
Remove the motion for any further consideration	Postpone indefinitely	Yes	Takes precedence over main motion. Debate can extend to the discussion of the main motion. If approved, it effectively "kills" the motion. Useful for disposing of a badly chosen motion that can not be adopted or rejected without undesirable consequences.
Request a review of procedure	Point of order	No	Second not required. The Chair or secretary shall review the parliamentary procedure used during the discussion of the Motion.

Notes on Motions

Seconds. A Motion must have a second to ensure that at least two members wish to discuss the issue. The "seconder" is not recorded in the minutes. Neither are motions that do not receive a second.

Announcement by the Chair. The Chair should announce the Motion before debate begins. This ensures that the wording is understood by the membership. Once the Motion is announced and seconded, the Committee "owns" the motion, and must deal with it according to parliamentary procedure.

Voting

Voting Method	When Used	How Recorded in Minutes
Unanimous Consent	When the Chair senses that the Committee is substantially in agreement, and the Motion needed little or no debate. No actual vote is taken.	The minutes show "by unanimous consent."
Vote by Voice	The standard practice.	The minutes show Approved or Not Approved (or Failed).
Vote by Show of Hands (tally)	To record the number of votes on each side when an issue has engendered substantial debate or appears to be divisive. Also used when a Voice Vote is inconclusive. (The Chair should ask for a Vote by Show of Hands when requested by a member).	The minutes show both vote totals, and then Approved or Not Approved (or Failed).
Vote by Roll Call	To record each member's vote. Each member is called upon by the Secretary,, and the member indicates either "Yes," "No," or "Present" if abstaining.	The minutes will include the list of members, how each voted or abstained, and the vote totals. Those members for which a "Yes," "No," or "Present" is not shown are considered absent for the vote.

Notes on Voting

(Recommendations from DMB, not necessarily Mr. Robert)

Abstentions. When a member abstains, he is not voting on the Motion, and his abstention is not counted in determining the results of the vote. The Chair should not ask for a tally of those who abstained.

Determining the results. The results of the vote (other than Unanimous Consent) are determined by dividing the votes in favor by the total votes cast. Abstentions are not counted in the vote and shall not be assumed to be on either side.

"Unanimous Approval." Can only be determined by a Roll Call vote because the other methods do not determine whether every member attending the meeting was actually present when the vote was taken, or whether there were abstentions.

Majorities. Robert's Rules use a simple majority (one more than half) as the default for most motions. NERC uses 2/3 majority for all motions.

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL
Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5731

Functional Model Working Group+
Roster

Member	Organization	Contact Information	Region
James D. Cyrulewski	**Michigan Electric Power Coordination Center** 39500 Orchard Hill Place Suite 205 Novi, Michigan 48375	Phone: (248) 374-7130 Fax: (248) 374-7135 jcyrulewski@itctransco.com	ECAR
Scott Moore	**American Electric Power** 1 Riverside Plaza 4th Floor Columbus, Ohio 43215	Phone: (614) 413-6600 Fax: (614) 716-6600 spmoore@aep.com	ECAR
John Stough	**American Electric Power** 1 Riverside Plaza 4th Floor Columbus, Ohio 43215	Phone: (614) 223-2708 Fax: fjstough@aep.com	ECAR
James A. Byrd	**Oncor** 2233-B Mountain Creek Parkway Dallas, Texas 75211–6716	Phone: (214) 486-6870 Fax: (972) 263-6710 jbyrd@oncorgroup.com	ERCOT
Steve Myers	**Electric Reliability Council of Texas** 2705 West Lake Drive Taylor, Texas 76574	Business: (512) 248-3077 Fax: (512) 248-3005 smyers@ercot.com	ERCOT
Linda Campbell	**Florida Reliability Coordinating Council** 1408 North Westshore Boulevard Suite 1002 Tampa, Florida 33607–4512	Phone: (813) 289-5644 Fax: (813) 289-5646 lcampbell@frcc.com	FRCC
Joe Willson	**PJM Interconnection, L.L.C.** 955 Jefferson Avenue Valley Forge Corporate Center Norristown, Pennsylvania 19403–2497	Phone: (610) 666-8820 Fax: (610) 666-2299 willsojd@pjm.com	MAAC
Albert M. DiCaprio	**PJM Interconnection, L.L.C.** 955 Jefferson Avenue Valley Forge Corporate Center Norristown, Pennsylvania 19403–2497	Phone: (610) 666-8854 Fax: (610) 666-4282 dicapram@pjm.com	MAAC

Andrew J. Rodriquez	**PJM Interconnection, L.L.C.** 955 Jefferson Avenue Valley Forge Corporate Center Norristown, Pennsylvania 19403–2497	Phone: (610) 635-3438 Fax: rodria@pjm.com	MAAC
Anthony Jankowski	**We Energies** W237 N1500 Busse Road Waukesha, Wisconsin	Phone: (262) 544-7117 Fax: (262) 544-7099 Tony.jankowsk@we-energies.com	MAIN
Robert (Bob) Millard	**Mid-America Interconnected Network, Incorporated** 939 Parkview Boulevard Lombard, Illinois 60148–3267	Phone: (630) 261-2621 Fax: (630) 691-4222 rwm@maininc.org	MAIN
Mike Risan	**Basin Electric Power Cooperative** 1717 East Interstate Avenue Bismarck, North Dakota 58503–0564	Business: (701) 355-5645 Fax: (701) 224-5332 mrisan@bepc.com	MRO
Ken Kuyper	**Corn Belt Power Cooperative** 1300 13th Street North American Electric Reliability Council P.O. Box 508 Humboldt, Iowa 50548	Phone: (515) 332-2571 ext. 243 Fax: (515) 332-1375 kenk@cbpower.com	MRO
Stanley E. Kopman	**Northeast Power Coordinating Council** 1515 Broadway 43rd Floor New York, New York 10036-8901	Phone: (212) 840-1070 Fax: (212) 302-2782 skopman@npcc.org	NPCC
Karl Tammar	**New York ISO** 3890 Carman Road Schenectady, New York 12303	Business: (518) 356-6129 Fax: (518) 356-6118 ktammar@nyiso.com	NPCC
Mike Yealland	**Independent Electricity System Operator** 126 Glen Road Toronto, ON, Canada M4W 2W2	Phone: (416) 923-6914 Fax: (416) 923-6914 mycon@sympatico.ca or mike.yealland@ieso.ca	NPCC
John Norden	**ISO New England, Inc.** One Sullivan Road Holyoke, Massachusetts 01040-2841	Phone: (206) 706-0165 Fax: (206) 706-0183 jnorden@iso-ne.com	NPCC
R. S. (Scott) Henry	**Duke Power Company** 526 South Church Street P.O. Box 1006 Charlotte, North Carolina 28201–1006	Phone: (704) 382-6182 Fax: (704) 382-4671 rshenry@duke-energy.com	SERC
Brian Thumm	**Entergy Services, Inc.** P.O. Box 61000 New Orleans, Louisiana 70161	Phone: (504) 310-5818 Alternate: (225) 754-7484 bthumm@entergy.com	SERC
Dennis Chastain	**Tennessee Valley Authority** 1101 Market Street MR–3K Chattanooga, Tennessee 37402	Phone: (423) 751-3950 Fax: (423) 751-4126 dwchastain@tva.gov	SERC

Michael L. Oatts	**Southern Company Services, Inc.** P.O. Box 2641 Birmingham, Alabama 35202–2625	Phone: (205) 257-7743 Fax: (205) 257-5083 mloatts@southernco.com	SERC
J. Roman Carter	**Southern Company Generation and Energy Marketing** 600 North 18th Street, GS-8259 Birmingham, Alabama 35291-8210	Phone: (205) 257-6027 Fax: (205) 257-4441 jrcarter@southernco.com	SERC
Gerald W. Burrows	**Kansas City Power & Light Company** P.O. Box 418679 Kansas City, Missouri 64141–9679	Phone: (816) 654-1183 Fax: (816) 654-1189 gerry.burrows@kcpl.com	SPP
Charles Yeung	**Southwest Power Pool** 415 North McKinley, Suite 140 Little Rock, Arkansas 72205–3020	Phone: (832) 724-6142 cyeung@spp.org	SPP
Gerry W. Cauley	**North American Electric Reliability Council** 116-390 Village Boulevard Princeton, New Jersey 08540–5731	Phone: (609) 452-8060 Fax: (609) 452-9550 gerry.cauley@nerc.net	STAFF
Donald M. Benjamin	**North American Electric Reliability Council** 116-390 Village Boulevard Princeton, New Jersey 08540–5731	Phone: (609) 452-8060 Fax: (609) 452-9550 donald.benjamin@nerc.net	STAFF
William D. Blevins	**North American Electric Reliability Council** 116-390 Village Boulevard Princeton, New Jersey 08540–5731	Phone: (609) 452-8060 Fax: (609) 452-9550 bill.blevins@nerc.net	STAFF
Virginia C. Sulzberger	**North American Electric Reliability Council** 116-390 Village Boulevard Princeton, New Jersey 08540–5731	Phone: (609) 452-8060 Fax: (609) 452-9550 virginia.Sulzberger@nerc.net	STAFF
John R. Twitchell	**North American Electric Reliability Council** 116-390 Village Boulevard Princeton, New Jersey 08540–5731	Phone: (609) 452-8060 Fax: (609) 452-9550 john.twitchell@nerc.net	STAFF
Mark Fidrych	**Western Area Power Administration** MC J0003 P.O. Box 3700 Loveland, Colorado 80539–3003	Phone: (970) 461-7240 Fax: (970) 461-7299 fidrych@wapa.gov	WECC
Kevin Conway	**Grant County PUD** Utility District No.2 of Grant County P.O. Box 878 Ephrata, Washington 98823	Business: (509) 754-6639 Fax: (509) 754-6757 kconway@gcpud.org	WECC
Michael C. Raezer	**Tucson Electric Power Company** 3950 East Irvington Road P.O. Box 711 Tucson, Arizona 85714	Phone: (520) 745-7167 Fax: (520) 745-3348 mraezer@tep.com	WECC

Donald E. Badley	**Northwest Power Pool** 26 S.W. Salmon Street, Suite 400 (3WTC0402) Portland, Oregon 97204-2991	Phone: (503) 464-2805 Fx: (503) 819-4517 don.badley@nwpp.org	WECC
James H. Hartwell	**Northeast Power Coordinating Council** 1515 Broadway, 43rd Floor New York, New York 10036-8901	Phone: 212) 840-4904 Fax: (212) 302-2782 jhartwell@npcc.org	NPCC
John P. Hughes	**Electricity Consumers Resource Council** 1333 H Street, N.W., 8th Floor, West Tower Washington, D.C. 20005	Phone: (202) 682-1390 Fax: (202) 289-6370 jhughes@elcon.org	

Item 2. Meeting Objectives

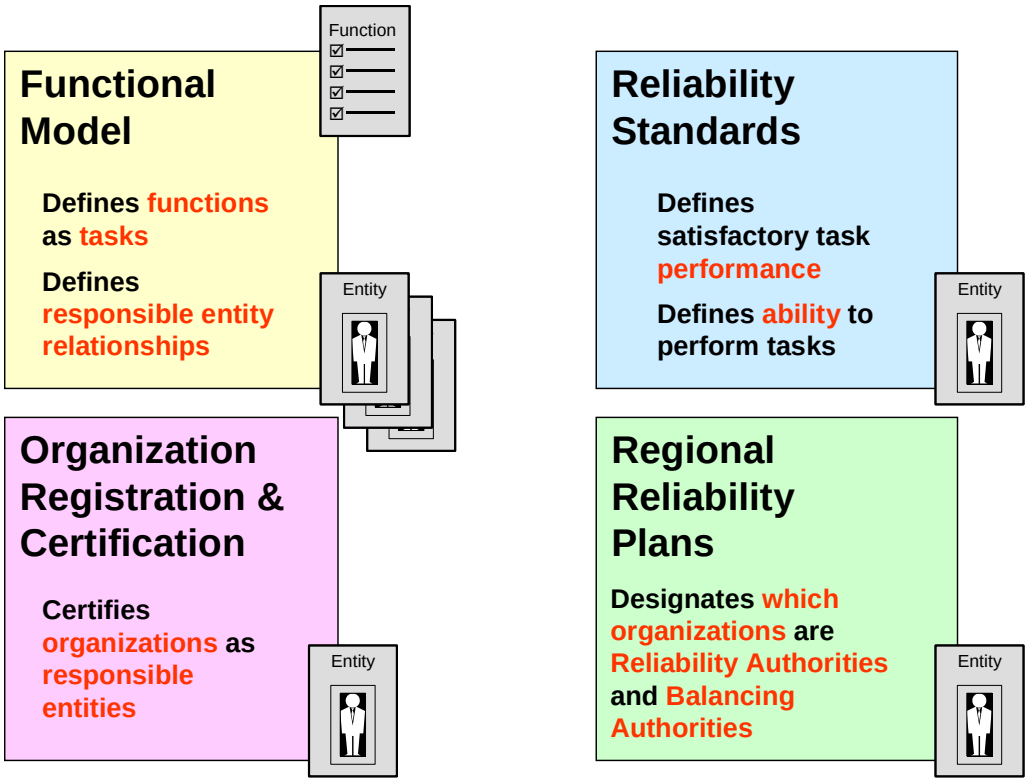
Action

Discussion

Background

Chairman Cyrulewski will review the meeting objectives, and we'll make whatever adjustments are needed. Here's what we need to do at a minimum:

1. Review the various documents that accompany this agenda and understand the role that each document plays.
2. Review the Purpose and Guiding Principles of the Functional Model.
3. Review the purpose of the Regional Reliability Plans.
4. Decide on the approach for dealing with each of the recommendations.
5. Discuss timeline and "deliverables."
6. Decide on near-term deadlines and set agenda for next meeting.
7. Begin work (time permitting).



Item 3. Document Review

Action

Discussion

Attachments

The following table lists the documents that we've attached and an explanation of their purpose.

Document	Purpose
1. Recommendations from the Functional Model-Reliability Standards Coordination Task Force and the Interchange Authority Implementation Task Force	The collection of the recommendations from these two groups. We'll use this list to direct our work.
2. Functional Model-Reliability Standards Coordination Task Force Final Report	Reference. The markups to the Functional Model in Appendix F are suggestions that the FMWG+ may wish to refer to. This markup includes the comments that NERC received on the Functional Model – Version 2 that we posted in early 2004.
3. Interchange Authority Implementation Task Force Final Report	Reference. Note that this report includes recommendations for the near-, mid-, and long-term timeframes. We will deal with the near-term recommendations.
4. Functional Model – Version 2	This is the version of the Functional Model that we'll be working on. We'll bring our revisions to the standing committees and Board of Trustees for approval.
5. Functional Model – Technical Document – Version 10	This is the latest version of the Technical Document that accompanies the Functional Model. We'll revise this document as necessary.

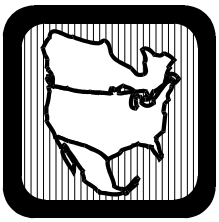
Recommendations from the Functional Model-Reliability Standards Coordination Task Force and the Interchange Authority Implementation Task Force

Item	*Comments and Action*
Functional Model	
1. **Developing standards to meet reliability objectives.** Reliability standards should be developed to meet justifiable reliability objectives, not solely to codify the functions and tasks defined in the Functional Model. The Functional Model represents a set of guiding principles for the development of reliability standards. It provides definitions and interrelationships to be taken into account in the development of standards. The Functional Model does not itself establish a minimum set of reliability requirements or define who should be responsible for reliability requirements. (Rec 1)	This concept is covered in the Guiding Principles of the Functional Model. **Action**: Review Guiding Principles of the Functional Model to ensure this concept is clearly explained. Also, we need to consider ways to more broadly advertise the relationship between the model and the standards.
2. **Revising standards and the model.** The Functional Model and reliability standards may need to be revised from time to time to maintain an appropriate degree of consistency. (Rec 2)	Do we need some kind of formal process for these reviews? Standards are supposed to be reviewed every five years.
3. **Responsible entity titles.** Titles of responsible operating entities described in the Functional Model should be revised to emphasize both the wide-area role of the reliability authority and the authority of the transmission operator for reliability within its responsibility area. For example, the reliability authority should be an "interconnection reliability authority" and the transmission operator should be a "transmission authority". (Rec 4)	**Action**: Consider changes to the Reliability Authority and Transmission Operator names, tasks, and interrelationships. Also, review Technical Document for additional clarifying descriptions.
a. **Reliability Authority.** The Interconnection Reliability Authority definition, tasks and interrelationships in the Functional Model should be revised to focus on interconnection reliability and coordination of reliability among its transmission authorities. The concept of 'highest authority' as it appears in the Functional Model should be modified to recognize multiple responsible entities can have 'an' authority to direct actions to operate reliably within their area and scope of responsibility. For example, the transmission authority may have authority to direct actions to protect its own system. It is important that this shift not be seen as diminishing the authority of the interconnection reliability authority from directing actions to preserve the reliability of the interconnection. This authority must remain explicit in the Functional Model. It should also be explicit that other responsible entities must follow these interconnection reliability authority directives, subject to safety, equipment, environmental, statutory and regulatory requirements. (Rec 5)	**Action**: Review defining of the RA and revise as needed to incorporate these concepts.

Item	*Comments and Action*
b. **Transmission Operator.** The transmission authority definition, tasks and interrelationships in the Functional Model should be revised to strengthen its authority and responsibilities to manage reliability within its area, subject to oversight by the interconnection reliability authority looking at interconnection-related issues. (Rec 6)	**Action**: Review defining of the Transmission Operator and revise as needed to incorporate these concepts.
4. **Interchange Authority.** The interchange authority should remain in the Functional Model but should be renamed the "interchange coordinator". The interchange coordinator should be implemented in stages as driven by reliability need or business justification. The interchange coordinator definition, tasks and interrelationships should be modified to allow more flexibility and should be less prescriptive of a particular business model. (Rec 15)	**Action**: Consider changes to the Interchange Authority. Also, review Technical Document for additional clarifying descriptions. See "Near Term" recommendations a., b., and c. from the IAITF report below.
a. **Rename the IA.** Rename the Interchange Authority to Interchange Coordinator. The formal change in name from IA to IC may remove some concern with the use of the word "authority" and may more closely reflect actual practice and expectations.	**NOTE: These three recommendations are still draft. Minor changes expected.**
b. **Revise IS definition.** Revise the definition of the IA to remove the term "authority" and replace it with the term "coordinate". Modify the definition of Interchange Authority in the Functional Model as follows: ~~Authorizes~~ *Coordinates and communicates* implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures Interchange *is* ~~Transactions are~~ properly identified for reliability assessment purposes. In addition, the tasks of the IA should be modified to more closely reflect this definition as outlined in Appendix A. The relationship of the IA with other functional entities should be modified as shown in Appendix B.	
c. **Including IA tasks into the BA.** Modify the Functional Model (as identified in Appendix A & B) to include the revised IA tasks under the Balancing Authority. (Note: This may not require a wholesale change to the Functional Model. Mapping of tasks to the BA can be done with an explanatory note without removing the IA from the Functional Model.)	Need to use caution here.
d. **Separating the IA.** The current interchange functions bundled with the balancing authority in the new standards should be separated and made to apply to the interchange authority (coordinator) when these standards are next revised. (Rec 16)	From the FMRSCTF, and would accommodate the "Mid-Term" recommendations of the IAITF.

Item	*Comments and Action*
5. **Planning Authority**. The planning authority in the Functional Model should be revised to be named an "interconnection planning coordinator". The definition, tasks and interrelationships of the interconnection planning coordinator, transmission planner, resource planner, and transmission owner should be modified as necessary to recognize that transmission planners, resource planners, and transmission owners have certain authorities in the planning process. The interconnection planning coordinator description should be revised to emphasize the wide-area oversight, coordination, and integration of transmission and resource plans across systems. (Rec 8)	**Action**: Consider changes to the Planning Authority. Also, review Technical Document for additional clarifying descriptions.
Regional Reliability Plan Outlines	
6. **Regional reliability plans.** Regional reliability organizations should be tasked to document how reliability responsibilities are assigned and integrated within the region to achieve reliable planning and operation of bulk electric systems. Initially these plans should include balancing authorities, transmission authorities, interconnection reliability authorities, interconnection planning coordinators, transmission planners, resource planners, and transmission owners. These plans should identify the interrelationships between the various responsible entities providing these functions. Regional reliability process plans need to be consistent and meet certain criteria necessary for interconnection reliability, but also should be flexible in meeting the regional reliability and organizational needs. Identification of responsible entities within the plans should evolve over time to remain current with actual authorities, responsibilities and relationships. These plans should subsume previous regional reliability plans focused on reliability coordinators, as well as efforts to develop responsible entity templates. The plans should be maintained current and should be periodically reported. (Rec 7)	**Action**: Develop Regional Reliability Plan requirements and specifications. We'll need to pick up the work of the RCPTF.
7. **Boundary constraints.** Mandatory boundary constraints between responsible entities should be set at the minimum threshold necessary for the reliability of the interconnections. Otherwise there should be no restrictions on boundary conditions between responsible entities. These criteria should be set through an open process and adopted into organization certification standards. (Rec 9)	Need to define in the Organization Certification standards, and address in the Regional Reliability plan outlines.
8. **Accountability linked to assets.** Accountability for operating and planning tasks should be clearly linked to bulk electric system assets. Each bulk electric system asset should be addressed by a single responsible entity for each function. These accountabilities should be documented in the regional reliability process plans. (Rec 10)	Address in the Regional Reliability Plans outlines.

Item	*Comments and Action*
Compliance and Accountability	
9. **Accountability.** Responsible entities should be held accountable for compliance with reliability standards. Compliance monitoring should be measured against the reliability standards. This should not preclude using the Functional Model as a guide for identifying entities that should be accountable for meeting reliability standards. All responsible entities for a particular function must be held to a consistent set of performance criteria with no regard to the size of the responsibility area or facilities within that area. (Rec 3)	Is this the current direction of the compliance program? **Action**: Discuss this with the VP of Compliance.
a. **Goals.** A goal is that all responsible entities should be accountable for compliance with all reliability standards applicable to that responsible entity. (Rec 11)	Recommendation 3 makes a point that compliance is measured by standards, not by the FM. Recommendation 11 gets at the question of whether you have to comply with all standards as, for instance, a TOP or just the tasks that you perform. The FMRSCTF recommends you need to meet all standards for a TOP. They also apply this goal to all entities, e.g. LSE, PA, TP, etc.
b. **Certification.** All entities having primary responsibility for reliable operation of the bulk electric systems should be certified in accordance with an associated organization certification standard. Initially, the interconnection reliability authority, the balancing authority, and the transmission authority should be certified. Each such responsible entity should be certified to have the capability to perform all requirements assigned to the function(s) it serves, as defined in the certification standards. (Rec 12)	**Action**: Discuss this with the VP of Compliance.
10. **Documenting delegation.** Delegation or division of responsibilities among responsible entities should be documented in writing, such as through formal agreements, market protocols, interconnection and service agreements, procedures, standing orders, etc. (Rec 13)	Where does this belong? Standards? Organization certification (based on standards)?
11. **Reliability relevance thresholds.** Reliability relevance thresholds should be considered as standards are developed, as well as in compliance monitoring. Assigning applicability and a burden for compliance monitoring should have a positive benefit for bulk electric system reliability. When possible, any applicability thresholds should be documented in the standards themselves. (Rec 14)	Compliance measures?



NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL
Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5731

Recommendations to Facilitate Use of the Functional Model to Guide the Development and Application of Reliability Standards

Prepared by
Functional Model – Reliability Standards Coordination Task Force

Final
March 11, 2005

A New Jersey Nonprofit Corporation

Phone 609-452-8060 ■ Fax 609-452-9550 ■ URL www.nerc.com

Table of Contents

Section 1 – Introduction

Purpose

This report recommends actions and guiding principles to facilitate the practical use of the Functional Model in the development of bulk electric system reliability standards. The report specifically addresses several issues that would otherwise remain as impediments to further development of reliability standards, including organization certification standards. In addition to paving the way for development of standards, the recommendations are expected to facilitate broader understanding, acceptance, and use of the Functional Model.

This report offers recommendations to guide resolution of key issues related to the Functional Model that were encountered in the development and implementation of NERC's new reliability standards. The report identifies areas where the Functional Model should be clarified to facilitate further development of reliability standards. Additionally, the report recommends the development of regional reliability process plans to document how operating and planning responsibilities are assigned and coordinated within each region to meet reliability objectives. The report is intended to guide the activities of various groups doing this work, as well as drafting teams that are developing reliability standards, including organization certification standards. The report is also intended to aid regions and entities tasked with mapping complex organization structures and relationships to the standards, consistent with the guiding principles of the Functional Model.

Functional Model – Reliability Standards Coordination Task Force

The Functional Model – Reliability Standards Coordination Task Force developed this report and its recommendations. The charter of the task force was to develop recommendations to resolve issues encountered in the development of the new reliability standards and initial registration of responsible entities. The recommendations focus on achieving compatibility and effective coordination between reliability standards and the Functional Model. The task force, which reports to the Technical Steering Committee, provides a diverse range of expertise and stakeholder perspectives. The task force scope is provided in Appendix A and the roster is in Appendix B.

Report Organization

The report begins with a general background in Section 2. Section 9 presents a summary list of recommendations and an action plan. Sections 3 to 8 describe issues in the following areas and present recommendations to resolve each issue:

- Section 3 – Clarifying relationships between reliability coordinators, reliability authorities and transmission operators.
- Section 4 – Mapping the complexities of real world organizational structures, responsibilities, and relationships to the reliability standards to ensure effective accountability. Includes clarifying the relationships between planning authorities, transmission planners and resource planners.
- Section 5 – Respecting a minimum set of responsible entity boundary constraints to ensure reliability.
- Section 6 – Determining whether standards should be applied inclusively (i.e. each transmission operator is accountable for all transmission operator requirements) or selectively as needed.
- Section 7 – Addressing the omission of the interchange authority from the initial reliability standards.
- Section 8 – Addressing lessons learned from the initial registration of responsible entities to be monitored for compliance with the reliability standards.

Section 2 – Background

Accelerated Standards Transition

In response to the August 14, 2003, northeast blackout, the U.S./Canada Power System Outage Task Force recommended in April 2004 that: "NERC should reevaluate its existing reliability standards development process and accelerate the adoption of enforceable standards." To meet this recommendation and the February 2004 directives of the NERC board, the Standards Transition Management Team and the Standards Authorization Committee developed a plan to accelerate the transition to an initial set of reliability standards. The Board of Trustees approved the standards transition plan in June 2004.

The standards transition had a principal objective of translating existing operating policies, planning standards, and compliance templates into the format of reliability standards, without changing the intent or effect of the existing reliability rules. A second objective was to develop the standards within the framework of the NERC Functional Model, to the extent possible in the expedited schedule. This meant adopting Functional Model definitions of responsible entities in place of less specific terms previously used in NERC's operating policies and planning standards, such as "control areas", "operating authorities", and "entities responsible for reliability."

In December 2004, stakeholders approved the new reliability standards by a weighted average of greater than 95% across all nine industry segments. On February 8, 2005, the NERC board adopted the new standards and set an effective date of April 1, 2005. These new reliability standards achieve an important milestone for NERC and the electric industry by improving accountability for the reliable operation and planning of North American electric power grids.

Challenges Applying Functional Model in Reliability Standards

The transition to new reliability standards faced several challenges that were addressed on an interim basis. However, these issues require further work to prepare a clear path forward from the initial set of standards. The source of the challenges centered mostly on the differences between the existing operating policies and planning standards and the Functional Model. These differences are not surprising, since the documents had different origins.

The Functional Model establishes a guiding framework for the development of standards and organization certification requirements. The Functional Model describes a generic unbundling of reliability functions that is meant to be adaptable to any market or organizational structure. It should not be viewed as a prescriptive formula or a threshold set of requirements for reliability. A more detailed tutorial on the Functional Model is provided in Appendix C.

Originally applied to vertically integrated utilities, the operating policies and planning standards historically assumed reliability tasks were assigned to control areas, and did not identify how responsibilities should be reassigned as control area functions became unbundled in many parts of North America. The operating policies and planning standards used several general terms, such as "operating authorities" and "entities responsible for reliability". The operating policies also incorporated requirements for reliability coordinators, which are not specifically defined in the Functional Model. As a result of these differences, it was not a simple task to map the operating policies and planning standards to the responsible entities defined by the Functional Model.

Reliability standards, unlike the Functional Model, provide detailed performance requirements and minimum capabilities of entities that operate and plan bulk electric systems. Standards are stated in terms that are intended to be objective and measurable. The initial set of reliability standards is a transitional step that adopts into practice some aspects of the Functional Model, but not the entire model.

In fact, it should not be expected that the Functional Model will ever in a strict sense be placed entirely into practice. The Functional Model is and will continue to be a framework of principles to guide the development of standards. There will always be practical limitations in mapping the complexities of real world organization structures, responsibilities, and authorities into the ideals described by the Functional Model. The Functional Model is not an end point to be reached, but a guiding framework for the journey. The goal is to develop standards to meet reliability objectives, guided by the framework of the Functional Model, and to maintain consistency between the standards and the Functional Model as both evolve.

Challenges in Mapping Responsible Entities to the Standards

In addition to using Functional Model definitions to designate responsible entities in the standards, NERC requested the regional reliability organizations to develop an initial mapping of organizations that would be monitored for compliance with the standards. Mapping of organizations as responsible entities reinforces accountability by identifying for the NERC and regional compliance monitoring programs which requirements apply to which organizations.

This was the first attempt by the industry at a wide-scale mapping of organizations to responsible entities defined in the Functional Model. This mapping of entities, driven by a need for more transparent accountability for following standards, required a different perspective on how the Functional Model had been historically viewed. A fundamental premise of the Functional Model is that it does not define or constrain organizational structures. Conceptually, the Functional Model can be thought of as unbundling reliability functions into "desks" where tasks are performed within an organization or across organizations. The model is neutral to the actual structure of those organizations because it addresses only functions performed at those conceptual "desks".

But the goal of naming entities that are accountable for complying with the new reliability standards has driven the development of a responsibility matrix that does tie real organizations to the responsible entities defined in the model. The initial registration names the organizations who serve as balancing authorities, transmission operators, reliability coordinators, planning authorities, and transmission planners. In the process of this exercise, a number of questions have been raised that this report attempts to resolve. The mapping of responsible entities is expected to continue evolving progressively as reliability and organization certification standards are developed. Once again, it is understood that responsible entities are being mapped to approved reliability and certification standards, not to the Functional Model. The Functional Model is a guiding framework, not a set of obligatory requirements.

Positive Step Forward

While the challenges described above are not insignificant, the development of the new reliability standards provided an opportunity to make a first practical, industry-wide application of the Functional Model. The standards transition has achieved the objectives as planned, but additional work is yet to be done, both with the standards and the Functional Model. Resolving the issues described in this report is essential for further development of reliability standards and organization certification criteria, and for ensuring that the NERC and regional compliance programs have the information they need on who to monitor for compliance with the standards.

Recommendations

1. Reliability standards should be developed to meet justifiable reliability objectives, not solely to codify the functions and tasks defined in the Functional Model. The Functional Model represents a set of guiding principles for the development of reliability standards. It provides definitions and interrelationships to be taken into account in the development of standards. The Functional Model does not itself establish a minimum set of reliability requirements or define who should be responsible for those requirements.

2. The Functional Model and reliability standards may need to be revised from time to time to maintain an appropriate degree of consistency.

3. Responsible entities should be held accountable for compliance with reliability standards. Compliance monitoring should be measured against the reliability standards. This should not preclude using the Functional Model as a guide for identifying entities that should be accountable for meeting reliability standards.

Section 3 – Relationships between Reliability Authority, Reliability Coordinator and Transmission Operator

Issue Summary

- The Functional Model does not specifically name the reliability coordinator as a responsible entity, yet reliability coordinators exist today and provide important reliability functions.

- The tasks currently assigned to reliability coordinators in operating policies (and now the new reliability standards) do not fully align with the functions and authorities of the reliability authority.

- The reliability coordinator is clearly intended to have a wide-area view of reliability for the interconnection and to coordinate reliable operations among systems, but the Functional Model does not explicitly refer to a wide-area perspective for the reliability authority.

- Reliability coordinators vary in their responsibilities, authorities, and delegation of tasks, making a clear relationship to the Functional Model elusive.

- The reliability authority is described in the Functional Model as the single highest authority for reliability. However, that position does not accommodate a common situation where there are both wide-area and local responsibilities and authorities for reliability that are complementary. The Functional Model is not clear that authorities for reliability really exist at multiple levels and across functions.

- Because the reliability authority is defined as the single highest authority, there will be a tendency to oversubscribe the population of reliability authorities to include both regional and local entities. This will further confuse the efforts to reconcile the differences between reliability coordinators and reliability authorities.

- The current standards use reliability coordinators and do not include reliability authorities. There is no clear path forward for the further development of standards, including organization certification standards, until the relationship between the reliability coordinator and reliability authority is understood.

Reliability Authority – Reliability Coordinator Relationship

The most significant challenge of the standards transition was a lack of understanding and agreement within the industry how reliability coordinators relate to the Functional Model. The Functional Model does not specifically name the reliability coordinator as a responsible entity, yet reliability coordinators exist today and provide important reliability functions.

While some thought the reliability coordinator and reliability authority were the same, others noted substantive differences in authorities and responsibilities that precluded them from being the same. There were several major obstacles in linking the reliability coordinator to the reliability authority. First, the tasks currently assigned to reliability coordinators in operating policies (and now the new reliability standards) do not align with the functions and authorities of the reliability authority. While there are similarities, the differences are sufficient to raise questions whether reliability coordinators and reliability authorities are really the same.

Compounding the difficulty is that existing reliability coordinators vary substantially among themselves. Although there is a general sense that reliability coordinators promote reliable operation of interconnected systems, there are varying approaches to how that is achieved. Simply stated, reliability coordinators vary

in their responsibilities, authorities, and delegation of tasks, making a clear relationship to the Functional Model even more elusive.

Another major difference is that the reliability coordinator is clearly intended to have a wide-area view of reliability for the interconnection and to coordinate reliable operations among systems. Yet, the Functional Model does not explicitly refer to a wide-area perspective for the reliability authority. There has been some historical discussion of the reliability authority requiring a wide-area view of the interconnection, and this concept is supported in technical references. But the Functional Model does not make this an explicit responsibility of the reliability authority.

To the contrary, some in the industry believe that the reliability authority, as an unbundling of control area functions, is a local operating entity that does not need a wide-area view of the interconnection. Although that view would not be in obvious conflict with the Functional Model, it would be in conflict with the current role of the reliability coordinator. It would therefore contradict an assertion that the reliability coordinator is the same as the reliability authority.

Reliability Authority – Transmission Operator Relationship (Authority Issue)

A related issue in the translation of the standards was who has the highest level of authority for reliability? The Functional Model indicates that the reliability authority has the highest authority for reliability. This is a logical outgrowth of the approach of unbundling of functions historically assigned to control areas. One of the "desks" performed balancing functions; another did transmission operations. A third "desk" was needed to integrate balancing and transmission operations to ensure overall reliability. A result of this approach is that the Functional Model narrows the transmission operator functions and authorities, and emphasizes the transmission operator being under the supervision of a reliability authority.

This division of responsibilities does not easily accommodate a more common situation in which a regional or larger entity has certain responsibilities and authorities for reliability on a wide-area basis but a local transmission operator also has responsibilities and authorities for the reliable operation of facilities within its area. In these situations, the local transmission operator does more than simply switching bulk electric system elements. The local operator also monitors system flows and voltages as compared to System Operating Limits, and determines if elements can be removed for scheduled outages. One could argue in these cases there is a reliability authority at both the regional level and the local level. As a practical matter, however, that sets up a proliferation of reliability authorities with overlapping areas of responsibility and confusion about who is in charge. It also leaves unanswered how to incorporate the reliability coordinator, which is clearly not a local function, but a wide-area, regional function.

Theoretically, there is no inherent conflict in the model with the reliability authority having the highest level of authority for reliability. It is only when organizations are asked to designate whether or not they are reliability authorities that the problem becomes apparent. The heightened need for transparent accountability for meeting reliability standards does require designation of responsible entities and progress has been made down that path. However, as long as the reliability authority is described as the single highest authority for reliability, there will be a tendency to oversubscribe the population of reliability authorities and create conflicting overlaps between the regional and local levels.

Views regarding who is the reliability authority tend to follow business models. For areas operating with a regional market, it is typically easier to assign the RTO or ISO as the reliability authority. Others who do not operate in a regional market tend to be less willing or in some cases unable to cede the highest level of authority for reliability to a regional entity, such as a reliability coordinator or a separate reliability authority. Some claim there are legal obstacles to ceding to others their authority to reliably operate the transmission system under the franchise certificate that has been granted to them by the state, county or local jurisdiction.

It should be noted that the transmission operator responsibilities captured in the new reliability standards more closely align with the concept of a local reliability authority than the concept of a transmission operator as merely a switching function. The transmission operator in current standards is responsible for setting System Operating Limits and monitoring system conditions to remain within those limits. The transmission operator is responsible for planning and coordinating outages and performing reliability assessments. The transmission operator may also direct others, such as load-serving entities and distribution providers, to shed load in an emergency. These responsibilities and authorities result from the translation of the operating policies and clearly go beyond a simple switching function.

The authority issue is also to some extent about misperceptions. A portion of the misperception is introduced because the Functional Model uses "authority" in the name of some responsible entities and not in others. The implication to some is that certain entities have authority and others are just the "doers". The implication is that the reliability authority, balancing authority, interchange authority, and planning authority have ultimate authority within their responsibility domain. The reverse of that implication is that the transmission operator/owner and generator operator/owner do not. Closer to reality is that asset owners and operators do have very real authorities for the reliable operation and protection of their equipment and systems. The Functional Model is not clear that authorities for reliability really exist at multiple levels and across functions. By seeming to concentrate authority in certain responsible entities, the Functional Model creates a tendency toward more entities choosing to be designated as those responsible entities than is perhaps necessary or appropriate.

Impediment to Standards Development

Until resolved, the issues above present impediments to the further development of standards. As an interim measure, reliability coordinators have been retained in the new standards with tasks that carried over from the operating policies. Reliability authorities are not currently used in the standards. As long as the standards retain the reliability coordinator designation, there will be inconsistencies between standards and the Functional Model. There will also be uncertainty whether organization certification should focus on the reliability coordinator or reliability authority.

Standard drafting teams and industry stakeholders remain in a partial holding pattern, uncertain whether reliability and certification standards should be developed for reliability coordinators or reliability authorities. The impact is not limited to just the reliability coordinator and reliability authority tasks. Nearly all other responsible entities have interactions with the reliability coordinator or reliability authority. Until the reliability authority – reliability coordinator – transmission operator relationships are resolved, the hierarchical relationships among all responsible entities will be unclear. In short, resolution of this issue is essential for providing a clear path forward for development of reliability and certification standards.

Discussion of Recommendations

The task force agrees with the principle that there should be only one responsible operating entity with the word 'reliability' in the title. The general preference is to retain the reliability authority in the Functional Model and revise its definition, responsibilities and tasks to both incorporate the reliability coordinator tasks and accommodate increased authority and responsibilities for the transmission operator. This shift would focus the reliability authority's tasks on managing interconnection reliability and coordinating reliable operations among transmission operators.

Transmission Operator responsibilities in the Functional Model should be strengthened to explicitly recognize the responsibilities and authorities to operate the local transmission system. This would remove the barriers currently perceived with implementing the reliability authority as defined in the model and avoid an undesirable proliferation of reliability authorities. This approach is expected to reduce the current tension that has many local system operators wanting to sign up as reliability

authorities because the Functional Model gives the reliability authority the highest level of authority for reliability.

This approach recognizes there can be dual responsibilities for reliability without undermining reliability. On the one hand the reliability authority maintains interconnection reliability and coordinates reliable operations among transmission operators. The transmission operator is responsible for reliable operations of the local transmission system. While these two functions can reside within the same organization, it is not necessary that they do. The duality of the highest level of authority should not be seen as conflicting. These local and wide-area authorities may coexist and even overlap. If action must be taken to protect the interconnection, or the local transmission system, those actions must be respected by others. The Functional Model should explicitly describe these authorities.

There may also be an opportunity to emphasize the points above by changing the names of several responsible entities. The task force considered, for instance suggesting that all operating entities use "operator" (e.g., interconnection reliability operator instead of reliability authority and balancing operator instead of balancing authority). However the task force also heard concerns about appearing to diminish the perceived authorities of reliability entities. For that reason, the task force suggests that the entity titles should be: interconnection reliability authority, balancing authority and transmission authority. This naming emphasizes both the wide-area role of what was the reliability authority and the tangible authority of what was the transmission operator.

Recommendations

4. Titles of responsible operating entities described in the Functional Model should be revised to emphasize both the wide-area role of the reliability authority and the authority of the transmission operator. For example, the reliability authority should be an "interconnection reliability authority" and the transmission operator should be a "transmission authority".

5. The interconnection reliability authority definition, tasks and interrelationships in the Functional Model should be revised to focus on interconnection reliability and coordination of reliability among its transmission authorities. The concept of 'highest authority' as it appears in the Functional Model should be modified to recognize multiple responsible entities can have 'an' authority to direct actions to operate reliably within their area and scope of responsibility. For example, the transmission authority may have authority to direct actions to protect its own system. It is important that this shift not be seen as diminishing the authority of the interconnection reliability authority from directing actions to alleviate limit violations or preserve the reliability of the interconnection. This authority must remain explicit in the Functional Model. It should also be explicit that other responsible entities are expected to follow these directives, subject to safety, equipment, environmental, statutory and regulatory requirements.

6. The transmission authority definition, tasks and interrelationships in the Functional Model should be revised to strengthen its authority and responsibilities to manage reliability at the local system level, subject to oversight by the interconnection reliability authority looking at interconnection-related issues. The transmission authority should have authority for reliability matters on its own system, subject to the interconnection reliability authority overseeing reliability matters on an interconnection and inter-transmission authority basis.

Section 4 – Real-World Responsibilities Not Grouped Per Functional Model

Issue Summary

- Organizations have divided functions differently than the Functional Model. On a theoretical basis, that is not a problem. However, as standards are written to group responsibilities in accordance with the Functional Model, mapping of organizations accountable for compliance with standards becomes complex. The tasks and responsibilities of real organizations do not map one-for-one into the tasks assigned by reliability standards. This complexity was seen in the initial registration of responsible entities.

- Planning responsibilities are extensively diffused and shared among entities – many entities can have a role in the transmission and resource planning process. This makes tracking accountability in the planning area even more challenging than for operating functions.

Complexity of Real-World Division of Reliability Tasks

The Functional Model states that the functions it describes are grouped into logical, indivisible clusters. But many organizations today have divided these functions differently. Since the Functional Model itself does not define organizational structure, until now there has not been a problem. The approach was that entities would self-select which functions they thought they performed – and that's what they were.

What has changed is a need, driven by the August 2003 blackout and the adoption of the new reliability standards, to specifically name organizations that are accountable for meeting reliability standards. There is, for example, an assumption from the standards development and compliance monitoring perspectives that a transmission operator will comply with all of the standards that apply to a transmission operator. Delegation of tasks is acceptable but not delegation of responsibilities.

The differences between actual groupings of functions in the industry and the grouping of functions in the standards became apparent in the initial effort to register responsible entities to be monitored for compliance with the new standards. It is clear that the division of real-world responsibilities does not follow the neat groupings of the Functional Model, and hence the standards which are developed in the Functional Model framework. Actual division of responsibilities is affected by administrative documents such as market protocols, service agreements, and even an individual entity's own procedures. Many tasks are assigned by delegation, and often this delegation is understood but not formally documented. Often responsibilities are shared among entities by mutual agreement, without bright lines of separation. Assignment of responsibilities can often be designated by technical factors such as voltage levels or asset types.

Once again, the difference in grouping of functions between the real-world and the Functional Model is not an issue per se. The problem of tractability arises when real-world grouping of tasks is different than the grouping of tasks in the reliability standards. Standards developers are instructed to use the Functional Model as a guide for division of responsibilities. The result is a body of standards that, for example, apply generically to a transmission operator. However, actual transmission operator organizations may perform only a portion of those transmission operator tasks or may perform a few tasks related to other functions. The tasks and responsibilities of real organizations do not map one-for-one into the tasks assigned by reliability standards.

If accountability for standards could be tracked by placing the name of each organization next to each requirement or measure in the standards, then the problem would be alleviated. However, that capability is not currently available on a consistent basis across North America, and there may be questions about the appropriateness of tracking accountability to that level of detail.

Diffusion of Planning Responsibilities

Planning functions are even more complex and dispersed across entities than operating tasks. Many tasks are performed at a regional level or sub-regional level. Many tasks are coordinated through committees and working groups. There is not a close correlation between the alignment of planning responsibilities in the Functional Model and the real world. In industry today, many planning tasks are dispersed among multiple entities, making a clear assignment of accountability for planning standards difficult.

Further, there is not a consistent understanding among systems today as to who should be the planning authority and who should be the transmission or resource planner. It is not clear what role the RTO has in relation to planning and planning authority functions. In some regions, the regional reliability organization may also be a planning authority, or perform a portion of the planning authority tasks. Other regions are not comfortable with the regional reliability organization being a planner or planning authority and prefer it focus on setting regional criteria and compliance monitoring. For these reasons, some entities have initially identified themselves as transmission planners even though they perform only a few related tasks. Also there appears to be a proliferation of planning authorities in some regions.

There can be confusion between the responsibilities for planning versus the responsibilities for providing adequate resources and delivery systems in the future. Planning tasks for the system that exists may include analysis, setting of equipment ratings, and designing protection. These tasks are clearly linked to physical assets in the system. Planning for the future adequacy is more integrated across a system or systems. These differences may increase the difficulty of assigning and coordinating responsibilities for transmission and resource planning.

In some respects, a planning authority may be considered more of an aggregator or integrator of transmission and resource plans, than an authority. When the concept of a planning authority is used to assert authority that perhaps the transmission planner or resource planner does not have, then there is a tendency for more entities to elect to be planning authorities. The authorities and responsibilities to perform planning functions may in fact exist at multiple levels, as was previously described in the operating area. There is a strong analogy between the planning authority – planner relationship and the reliability authority – transmission operator relationship. The planning authority should have a wide-area view and integrate transmission and resource plans across multiple systems or a large area, rather than apply to a small, local system. An advantage of reinforcing the wide-area perspective of a planning authority is a reduction in the number and complexity of seams that need to be coordinated.

With the extensive diffusion of planning responsibilities across many entities, compliance monitoring in the near term may require identifying which entities are responsible for which requirements in the standards. It may not be possible in the near term to expect that each transmission planner or planning authority performs all tasks in the standards – many may just not be applicable. The assignment of planning responsibilities may also vary substantially from region to region.

Discussion of Recommendations

The task force recommends the development of regional reliability process plans that document how responsibilities are assigned and coordinated within the region. The task force recognizes the need for these regional plans to meet certain criteria for completeness and consistency. However, these plans should also to be sufficiently flexible to address unique regional reliability and organizational requirements. The regional reliability process plans should address all responsible entities monitored in the compliance program. Initially, this would include at least the balancing authority, transmission authority, or interconnection reliability authority, transmission owner, planning authority, transmission planner, and resource planner. The regional reliability process plans would subsume the regional reliability plans that currently focus on reliability coordinators. They would also incorporate the recent work to develop responsible entity templates, such as the balancing authority and reliability authority templates. A brief outline of regional reliability process plan requirements is provided in Appendix D.

These regional reliability process plans should be reviewed through regional and NERC processes. The plans are expected to evolve over time and remain dynamic as situations change in the region. The important thing is that the plans provide an accurate picture of how reliability functions in the region are assigned and coordinated to ensure reliability objectives are achieved.

The task force emphasizes that the regional reliability process plans do not need to be uniform. The plans should be compatible across the regions. The regions should use a consistent language and parameters in describing the reliability process. This consistency will facilitate review and understanding of the plans by others. At the same time, however, it is unnecessary to apply pressure for uniform solutions among regions. The iterative process of periodically updating and reviewing the plans will provide sufficient opportunity to promote consistency of the plans over time.

The task force acknowledges that sharing of responsibilities and diverse approaches exist in the planning area. There are not neat groupings of functions across the industry in the planning area. Regional reliability process plans should be used to mitigate any confusion by describing how planning functions are performed and coordinated within the region and by whom. The NERC and regional compliance programs should be prepared to mitigate the additional complexity of monitoring compliance in the planning area for several years as standards and compliance monitoring methods evolve.

The planning authority in the Functional Model should be revised to be named an “interconnection planning coordinator”. Its definition and responsibilities, along with those of the transmission and resource planners should be revised to strengthen the authorities and responsibilities of the planners so that it does not appear that authorities are concentrated solely with the planning authority.

Recommendations

7. Regional reliability organizations should be tasked to document how reliability responsibilities are assigned and integrated within the region to achieve reliable planning and operation of bulk electric systems. Initially these plans should include balancing authorities, transmission authorities, interconnection reliability authorities, transmission owners, interconnection planning coordinators, transmission planners, resource planners, and transmission owners. These plans should identify the interrelationships between the various responsible entities providing these functions. Regional reliability process plans need to be consistent and meet certain criteria necessary for interconnection reliability, but also should be flexible in meeting the regional reliability and organizational needs. Identification of responsible entities within the plans should evolve over time to remain current with actual authorities, responsibilities and relationships. These plans should subsume previous regional reliability plans focused on reliability coordinators, as well as efforts to develop responsible entity templates. The plans should be maintained current and should be periodically reported.

8. The planning authority in the Functional Model should be revised to be named an “interconnection planning coordinator”. The definition, tasks and interrelationships of the interconnection planning coordinator, transmission planner, resource planner, and transmission owner should be modified as necessary to recognize that transmission planners, resource planners, and transmission owners have certain authorities in the planning process. The interconnection planning coordinator description should be revised to emphasize the wide-area oversight, coordination, and integration of transmission and resource plans across systems.

Section 5 – Responsible Entity Boundary Constraints

Issue Summary

- The minimum set of responsible entity boundary constraints needed for reliability has not been formally defined and vetted through the standards process.

- Methods for assigning operational or planning responsibilities for portions of the bulk electric system are confusing and inconsistent.

Reliability Need for Boundary Constraints

The standards transition and initial entity registration raised questions regarding the need to specify boundary constraints between entities performing functions. Obvious examples are that all energized facilities connected to an interconnection need to be within a balancing area, that balancing areas do not overlap, and there are no gaps between balancing areas.

Although the Functional Model provides little definition of boundary constraints on various functions (e.g., a balancing authority area must be within a single reliability authority area), the question arises whether such constraints are necessary for reliability and should be addressed in organization certification standards or elsewhere. To date, there has not been a clear definition of what boundary constraints are the minimum necessary for reliability. Some constraints have been preliminarily suggested as part of the initial registration of entities responsible for compliance the new standards. An example is that each transmission operator and balancing authority area shall be within a single reliability coordinator area. However, such requirements have not been formally vetted and adopted through due process.

Apportioning Responsibilities across the Bulk Electric System

The initial registration of entities to the new reliability standards did not preclude mapping of multiple entities to a function within a geographic area, as long as each entity clearly has identified the portion of the bulk electric system over which it has primary responsibility for reliable operation or planning. There has been an inclination to think of responsibilities being assigned by (geographic or electrical) footprint, voltage level, or classes of facilities. However, these approaches can still be confusing and several questions have arisen. For example, can multiple transmission operators or balancing authorities be nested within others providing the same function? What if the self-selection of responsible entities results in overlapping responsibilities or gaps on the bulk electric system? A regional transmission operator may operate facilities at higher voltage levels and a local transmission operator may operate bulk electric system facilities at lower voltage levels within the same footprint.

Discussion of Recommendations

The task force believes that mandatory boundary constraints between responsible entities should be set at the minimum threshold necessary for the reliability of the interconnection. Otherwise there should be no restrictions on boundary conditions between responsible entities. These criteria should be set through an open process and adopted into organization certification standards. The Organization Certification WG should seek stakeholder input on boundary constraints that should be made part of the certification criteria.

The task force believes that to avoid confusion, overlaps, and gaps, responsibilities should be assigned based on bulk electric system assets. Operating and planning responsibilities should be clear for each element of the bulk electric system. In some cases, where a single entity has all of the responsibilities for a function over a wide area of the system, those responsibilities can be assigned broadly to one entity for the entire system. In other cases where the division of responsibilities is finer, responsibilities can be

assigned for facilities, elements, or even individual devices, as needed to create an accurate picture for accountability. The common denominator for assigning responsibilities should be asset-based. Using this approach allows assignment of responsibilities for non-contiguous elements – an entity may, for example, have a responsibility for specific devices, but not the entire system. The asset-based assignment of responsibilities should be clearly stated in the regional reliability process plans.

Recommendations

9. Mandatory boundary constraints between responsible entities should be set at the minimum threshold necessary for the reliability of the interconnections. Otherwise there should be no restrictions on boundary conditions between responsible entities. These criteria should be set through an open process and adopted into organization certification standards.

10. Accountability for operating and planning tasks should be clearly linked to bulk electric system assets. Each bulk electric system asset should be addressed by a single responsible entity for each function. These accountabilities should be documented in the regional reliability process plans.

Section 6 – Inclusive or Narrow Applicability of Standards

Issue Summary

- Inclusive applicability of standards (i.e. all standards apply to a responsible entity) may not be achievable in the near term, particularly for planning functions where responsibilities are shared and diffused across many entities.

- Delegation of tasks is prevalent today but in many cases is not sufficiently documented.

- It is not clear whether it is appropriate to apply a "bulk electric system reliability relevance threshold" when determining accountability for compliance with standards.

Applicability of Standards

The responsible entity registration guidelines recommended that each operating entity (reliability coordinator, balancing authority, and transmission operator) should be accountable for all reliability standards that apply to the respective function. Although each entity may delegate some tasks to other organizations, the designated responsible entity remains accountable for complying with all requirements within its defined area.

Accountability for compliance with reliability standards is most robust using an inclusive approach such as this. As a goal, there should be a preference toward making reliability standards applicable on an inclusive basis for all responsible entities.

On the other hand, this inclusive approach may have a detrimental effect of discouraging some entities who perform a portion of the tasks in a functional area from electing to be named a responsible entity. This effect is seen in the results of the initial registration as some entities that operate large systems did not appear as responsible entities. Responsibility was assigned instead to a regional entity, such as an RTO, and delegated as needed to the member entities.

Assigning inclusive responsibility for planning tasks is more difficult than operating tasks, and was not pressed in the initial registration of responsible planning entities. Ideally, in the long term, it would be preferable to move toward each responsible entity being accountable for the full set of planning standards related to that function. However, that will take time and the best approach in the interim is to document actual assignment of responsibilities within the regional reliability process plans.

Delegation of tasks is prevalent today and should be expected to continue as a means of accommodating the complex real-world relationships previously described. However, there needs to be much better documentation of delegation arrangements. Delegation arrangements can be documented through formal contracts or agreements. But they can also be satisfactorily recorded through market protocols, written procedures, standing orders, and other documents that entities have consented to follow.

Applicability is also an issue with regard to organization certification. Questions have been raised whether entities should be able to volunteer to be certified or certain entities should be required to be certified. The task force believes that there are certain responsible entities that should be required to be certified. Organization certification standards should be developed for each of these responsible entities and certification made mandatory for all entities performing those functions.

Reliability Relevance Threshold

It is not clear whether it is appropriate to apply a "bulk electric system reliability relevance threshold" when determining accountability for compliance with standards. A reliability relevance threshold would

indicate whether a particular task was relevant to bulk electric system reliability. As an example, there are certain requirements in the standards that apply to load-serving entities. With over two thousand load-serving entities in North America, some handling only a few customers, the question of relevance becomes an issue. Should there be thresholds of relevance where the benefits of assigning and monitoring compliance of an entity with the reliability standards are small or negligible compared to the burden? Consistent with the Functional Model, standards assign requirements generically to responsible entities, such as load-serving entities, distribution providers, generators, etc., without distinguishing size or impact on the bulk electric system.

Discussion of Recommendations

Standards for operating entities should to the maximum extent possible be applicable on an inclusive basis (i.e. all requirements apply to each responsible entity.)

As an ideal, standards for planning entities should also be applicable on an inclusive basis. However, on an interim basis if that is not practical, the allocation of responsibilities should be clearly documented in the regional reliability process plans.

Delegation arrangements should be documented in writing, such as through formal agreements, market protocols, interconnection and service agreements, procedures, standing orders, etc.

Reliability relevance thresholds should be considered as standards are developed and in compliance monitoring. Assigning applicability and a burden for compliance monitoring should have a positive benefit for bulk electric system reliability. When possible, any applicability thresholds should be documented in the standards themselves.

Recommendations

11. A goal is that all responsible entities should be accountable for compliance with all reliability standards applicable to that responsible entity.

12. All responsible operating entities defined by the Functional Model as having primary responsibility for reliable operation of the bulk electric systems should have an associated organization certification standard. Examples are the interconnection reliability authority, balancing authority, and transmission authority. Each such responsible entity should be certified to have the capability to perform all tasks assigned to the function(s) it serves, as defined in the reliability standards.

13. Delegation arrangements among responsible entities should be documented in writing, such as through formal agreements, market protocols, interconnection and service agreements, procedures, standing orders, etc.

14. Reliability relevance thresholds should be considered as standards are developed and in compliance monitoring. Assigning applicability and a burden for compliance monitoring should have a positive benefit for bulk electric system reliability. When possible, any applicability thresholds should be documented in the standards themselves.

Section 7 – Interchange Authority

Issue Summary

- The Interchange Authority was intentionally omitted from the new reliability standards because including it would have required substantial changes in the standards. More information is needed to determine whether and how the Interchange Authority should be incorporated into the standards.

- As an interim step, interchange tasks from Operating Policy 3 were assigned to balancing authorities. This has created an inconsistency between the Functional Model and the standards, since the Functional Model assigns only balancing tasks to the balancing authority.

- There is no clear reliability mandate to develop the interchange authority as outlined in the Functional Model. It is unclear if and when the interchange authority should be incorporated into reliability standards.

Omission of Interchange Authority from Initial Standards

The interchange authority defined in the Functional Model has not been included in the new reliability standards. Adopting the interchange authority into the standards would have required substantial changes to the reliability rules, operating practices, and tools. This is because the Functional Model allows interchange transactions between non-adjacent source and sink balancing areas, rather than the current "daisy chain" scheduling used today. The development of standards and tools to implement the interchange authority model was not justifiable or practical in the time frame of the standards transition project. NERC and NAESB subgroups are addressing the interchange authority functionality now and expect it to be implemented in the future.

The control area-based interchange tasks that were previously performed under Operating Policy 3 were instead assigned in the new standards to balancing authorities because they previously applied to control areas. Hence, the balancing authority has additional tasks in the standards that it does not have in the Functional Model and the interchange authority has not been addressed at all. However, this was not a necessary condition of the translation, since interchange functions could have been assigned to the interchange authority, if one accepts that the interchange authority is not necessarily a separate organization. In other words, the function currently managed by the sink balancing authority could be designated as a responsibility of the interchange authority within that organization. In most cases, the interchange authority would be in the same organization as the sink balancing authority, but that would not always be the case. This approach can be visualized as adopting an interchange authority "lite" based on current interchange coordination practices.

The interchange authority may not be developed in the near-term as described in the Functional Model. Because of the significant changes to tools and procedures required to fully implement the interchange authority model, a business justification is needed to implement the interchange authority. It has been demonstrated that the grid can be operated reliably using the existing 'daisy-chain' scheduling approach between balancing areas. In the mean time, there is a need to cope with the impact of this missing function on the responsibilities for standards applied to other functions.

Authority Role of Interchange Authority

The task force believes that the concept of "authorizing" transactions in the interchange authority responsibilities may imply a separate entity is performing that function. Today, that authorizing is a composite approval by all of the balancing areas and transmission service providers on the contract path

of the transaction. In today's practice, the interchange authority may be more of an interchange coordinator and the term "authority" may be causing confusion.

Discussion of Recommendations

As interchange-related standards are revised the next time, drafting teams should be instructed to consider assigning interchange coordination tasks to the interchange coordinator, in lieu of the sink balancing authority. The concept of interchange authority "lite" should be an acceptable approach for allowing the integration of the interchange authority into standards on an initial basis.

The existence of the interchange authority in the Functional Model does not itself justify development of interchange authority standards. These standards should be based on reliability need. These standards may also be developed as the industry feels there is a business case for implementing the protocols and tools that would be necessary to implement the interchange authority.

The interchange authority should be changed to an interchange coordinator to be more consistent with its responsibilities and interrelationships.

Recommendations

15. The interchange authority should remain in the Functional Model but should be renamed the "interchange coordinator". The interchange coordinator should be implemented in stages as driven by reliability need or business justification. The interchange coordinator definition, tasks and interrelationships should be modified to allow more flexibility and should be less prescriptive of a particular business model.

16. The current interchange functions bundled with the balancing authority in the new standards should be separated and made to apply to the interchange authority (coordinator) when these standards are next revised.

Section 8 – Initial Functional Registration of Entities

In addition to developing new reliability standards, NERC sought to identify the organizations that would be responsible for complying with the standards. Mapping of organizations as responsible entities has improved accountability for following the new reliability standards by identifying to the NERC and Regional compliance monitoring programs which requirements apply to which organizations. The preliminary matrix of responsible entities is provided in Appendix E.

The list of entities being monitored is intended to remain dynamic as entity responsibilities and relationships change. The list of functions to be monitored may be expanded from time to time as needed to meet the needs of the NERC and regional compliance programs. Each region should anticipate updating its list of responsible entities at least annually effective January 1 of each calendar year, and within 30 days of a change in a particular entity's status. NERC is expected to issue future requests to coordinate the timing of the scheduled updates.

This section describes several issues that were identified in the initial registration of responsible entities.

Issue Summary

- Some large SCADA centers may be shielded from accountability for reliability standards, although they have substantive responsibilities for the operation or planning of bulk electric systems.

- In some regions there has been a higher than expected number of planning authorities registered. This is inconsistent with the concept of the planning authority having a wide-area perspective and integrating transmission and resource plans across systems.

- Some new entities registered as balancing authorities and transmission operators who were not previously control areas. This raises the question whether these entities have been certified and are qualified to serve as balancing authorities or transmission operators. There is also a concern that not all control areas had previously completed there certifications in some regions.

- The registration of entities appears to have missed some entities that were previously identified in the TSIN registry as control areas. Although this is most likely due to outdated information in the TSIN registry, the omissions should be reviewed to ensure all systems are registered for compliance monitoring with the standards.

- Several standards are actively being monitored for compliance, but the applicable responsible entities were not registered. Most notable is that transmission owners are being monitored for the vegetation management standard. Several other monitored measures related to protection apply to generator owners and operators, load-serving entities, and distribution providers.

- Some entities who are not members of the regional reliability organization may not have been included in the registration data by some regions.

Large SCADA Centers as Transmission Operators

In several regions, RTOs have been initially designated as being responsible for a number of functions. A concern arises when operators of RTO member systems as large as 10,000 MW or more are not included on the list of responsible entities. The concern is that the chain of accountability for complying with reliability standards may be weakened in these instances. In contrast, entities in other regions operating systems of a few hundred MW are fully accountable for compliance with the standards.

It may be the case that accountability is achieved through RTO agreements and protocols that members must follow to operate and plan reliable systems. However, this approach leaves some concern that accountability may be too remote for entities operating large transmission systems and that the benefits of reliability through "defense in depth" are undermined.

As a mitigating measure, NERC and regional compliance programs should not be restricted from monitoring the larger SCADA centers as needed to verify compliance and including them in the readiness audits to help them strive for excellence in their reliability responsibilities. In the long term, there may be a need to develop criteria to ensure that the chain of accountability is strong and direct for all entities operating bulk electric system facilities.

Number of Planning Authorities

Several regions indicated a higher than expected number of planning authorities. The Functional Model anticipates the planning authority has a wider view than a single transmission system and coordinates transmission and resource planning over that wider area. One reason for a high number of planning authorities may be that NERC did not ask for resource planning entities and those who do resource planning registered as planning authorities to address that aspect of their responsibilities. A second reason may be that many transmission owners in the region believe they have the highest authority for integrated planning of their system and are not comfortable with another entity having oversight as their planning authority. Some indicated they registered as a planning authority because they participated in a regional planning process through a committee.

New Balancing Authorities or Transmission Operators

Several new balancing authorities or transmission operators appeared in several regions that were not previously known to NERC as control areas. The balancing authorities appear mostly to be "nested" areas within larger balancing authority areas. These entities appear now because the scope of functions in the standards has been narrowed to balancing, which is what some of them do. These entities did not qualify as a control area with the transmission reliability tasks included. Although these entities may in fact be balancing a metered system and meeting reliability standards, there is a concern that reliability may be undermined if these entities have not been certified as control areas, transmission operators, or balancing authorities.

As a transitional measure, it may be appropriate for regions to provide an interim form of certification (e.g., a subset of the control area certification or the results of a readiness audit) for the new or currently uncertified balancing authorities or transmission operators. This does not create a new certification requirement. It ensures that all existing control areas that become balancing authorities or transmission operators were certified and the registration process does not allow creation of a new balancing authority or transmission operator without some form of qualification review.

Unmapped Control Areas

Several control areas registered in the TSIN database did not register. NERC used the TSIN registry to cross reference the existing control areas to verify completeness of the registration data. These entities appear in the spreadsheet in Appendix E, but show a "0" under number of functions assigned. The discrepancies are most likely due to outdated TSIN information, but require follow up verification.

Additional Functions Being Monitored for Compliance

The initial registration requested by NERC did not include all entities that need to be monitored for compliance in 2005. For example, the vegetation management standard (FAC-003) applies to transmission owners. Other examples are related to system protection and apply to transmission owners,

generator owners, and in some cases distribution providers and load-serving entities (e.g., PRC-004, PRC-005, PRC-007, PRC-008, PRC-009, PRC-010, PRC-015, PRC-016, and PRC-017.) In lieu of expanding the functions on the registration list at this late date, all regions were requested to continue monitoring compliance of the entities that were previously monitored for these standards within each region.

Inclusion of All Load, Generation and Transmission Facilities

There is a need to verify that all load, generation, and transmission interconnected within the region is within one and only one balancing authority area; that each element of the bulk electric system is within one transmission operator's area of responsibility; and that each balancing authority and transmission operator is within a single reliability coordinator area.

Non-member Entities

Some regions noted that there were entities that operate or plan the bulk electric system but are not members of the region. Regions should be encouraged to identify all responsible entities within the region, regardless of regional affiliation.

Discussion of Recommendations

Recommendations applicable to the issues above have been addressed in prior sections.

The issues identified above were also addressed individually to each region as applicable. Responses have been requested by March 25, 2005.

This initial mapping of responsible entities should be viewed as a first step and should be progressively developed over time. It is intended to be a dynamic mapping. The mapping should be maintained and published by each regional reliability organization in dialog with its members.

The regional reliability process plan should be the primary tool for documenting responsibilities of entities within the region. The region and the entities must work together to reach mutual agreement on assigned functions. The region should publish the list of responsible entities and resolve any gaps or redundancies. Any conflicts should be adjudicated through a regional dispute resolution process.

Section 9 – Recommendations and Action Plan

Summary of Recommendations

The task force recommendations are summarized below. These recommendations offer guiding principles for the revision of the Functional Model, development of regional reliability process plans, and other actions to effectively coordinate the development of reliability standards with the Functional Model. An action plan for initiating the next steps is provided in the next section.

1. Reliability standards should be developed to meet justifiable reliability objectives, not solely to codify the functions and tasks defined in the Functional Model. The Functional Model represents a set of guiding principles for the development of reliability standards. It provides definitions and interrelationships to be taken into account in the development of standards. The Functional Model does not itself establish a minimum set of reliability requirements or define who should be responsible for reliability requirements.

2. The Functional Model and reliability standards may need to be revised from time to time to maintain an appropriate degree of consistency.

3. Responsible entities should be held accountable for compliance with reliability standards. Compliance monitoring should be measured against the reliability standards. This should not preclude using the Functional Model as a guide for identifying entities that should be accountable for meeting reliability standards. All responsible entities for a particular function must be held to a consistent set of performance criteria with no regard to the size of the responsibility area or facilities within that area.

4. Titles of responsible operating entities described in the Functional Model should be revised to emphasize both the wide-area role of the reliability authority and the authority of the transmission operator for reliability within its responsibility area. For example, the reliability authority should be an “interconnection reliability authority” and the transmission operator should be a “transmission authority”.

5. The interconnection reliability authority definition, tasks and interrelationships in the Functional Model should be revised to focus on interconnection reliability and coordination of reliability among its transmission authorities. The concept of ‘highest authority’ as it appears in the Functional Model should be modified to recognize multiple responsible entities can have ‘an’ authority to direct actions to operate reliably within their area and scope of responsibility. For example, the transmission authority may have authority to direct actions to protect its own system. It is important that this shift not be seen as diminishing the authority of the interconnection reliability authority from directing actions to preserve the reliability of the interconnection. This authority must remain explicit in the Functional Model. It should also be explicit that other responsible entities must follow these interconnection reliability authority directives, subject to safety, equipment, environmental, statutory and regulatory requirements.

6. The transmission authority definition, tasks and interrelationships in the Functional Model should be revised to strengthen its authority and responsibilities to manage reliability within its area, subject to oversight by the interconnection reliability authority looking at interconnection-related issues.

7. Regional reliability organizations should be tasked to document how reliability responsibilities are assigned and integrated within the region to achieve reliable planning and operation of bulk electric systems. Initially these plans should include balancing authorities, transmission authorities, interconnection reliability authorities, interconnection planning coordinators, transmission planners, resource planners, and transmission owners. These plans should identify the interrelationships between the various responsible entities providing these functions. Regional reliability process plans

need to be consistent and meet certain criteria necessary for interconnection reliability, but also should be flexible in meeting the regional reliability and organizational needs. Identification of responsible entities within the plans should evolve over time to remain current with actual authorities, responsibilities and relationships. These plans should subsume previous regional reliability plans focused on reliability coordinators, as well as efforts to develop responsible entity templates. The plans should be maintained current and should be periodically reported.

8. The planning authority in the Functional Model should be revised to be named an "interconnection planning coordinator". The definition, tasks and interrelationships of the interconnection planning coordinator, transmission planner, resource planner, and transmission owner should be modified as necessary to recognize that transmission planners, resource planners, and transmission owners have certain authorities in the planning process. The interconnection planning coordinator description should be revised to emphasize the wide-area oversight, coordination, and integration of transmission and resource plans across systems.

9. Mandatory boundary constraints between responsible entities should be set at the minimum threshold necessary for the reliability of the interconnections. Otherwise there should be no restrictions on boundary conditions between responsible entities. These criteria should be set through an open process and adopted into organization certification standards.

10. Accountability for operating and planning tasks should be clearly linked to bulk electric system assets. Each bulk electric system asset should be addressed by a single responsible entity for each function. These accountabilities should be documented in the regional reliability process plans.

11. A goal is that all responsible entities should be accountable for compliance with all reliability standards applicable to that responsible entity.

12. All entities having primary responsibility for reliable operation of the bulk electric systems should be certified in accordance with an associated organization certification standard. Initially, the interconnection reliability authority, the balancing authority, and the transmission authority should be certified. Each such responsible entity should be certified to have the capability to perform all requirements assigned to the function(s) it serves, as defined in the certification standards.

13. Delegation or division of responsibilities among responsible entities should be documented in writing, such as through formal agreements, market protocols, interconnection and service agreements, procedures, standing orders, etc.

14. Reliability relevance thresholds should be considered as standards are developed, as well as in compliance monitoring. Assigning applicability and a burden for compliance monitoring should have a positive benefit for bulk electric system reliability. When possible, any applicability thresholds should be documented in the standards themselves.

15. The interchange authority should remain in the Functional Model but should be renamed the "interchange coordinator". The interchange coordinator should be implemented in stages as driven by reliability need or business justification. The interchange coordinator definition, tasks and interrelationships should be modified to allow more flexibility and should be less prescriptive of a particular business model.

16. The current interchange functions bundled with the balancing authority in the new standards should be separated and made to apply to the interchange authority (coordinator) when these standards are next revised.

Next Steps

The milestones below outline recommended next steps to achieve the recommendations above. In the long term, the Functional Model should be periodically reviewed and revised as necessary. This work should be managed jointly by the groups with an interest in the Functional Model, including the Operating Committee, Planning Committee, Standards Authorization Committee, Compliance and Certification Committee, Compliance and Certification Managers Committee and the Critical Infrastructure Protection Committee.

Milestone	Schedule
Functional Model – Reliability Standards Coordination Task Force (FM-RSC TF) presents its final report to the Technical Steering Committee (TSC). TSC augments the Functional Model Working Group (FMWG) with members from the FM-RSC TF to provide continuity. TSC assigns the resulting FMWG+ to draft proposed revisions to the Functional Model and an outline to guide development of regional reliability process plans. The TSC appoints FMWG+ officers.	March 11, 2005
Staff reviews the FM-RSC TF report with the standing committees and requests endorsement the assignment of this work to the FMWG+.	Complete review by all committees by March 31, 2005
Director – Standards presents the FM-RSC TF report to standards drafting teams to guide standards development on an interim basis until Functional Model revisions are completed.	April 1, 2005
Director – Standards informs industry of proposed revisions to Functional Model and development of regional reliability process plans.	Public workshops on April 6-7 and April 14-15, 2005
Initial meeting of the FMWG+.	April 7-8, 2005
FMWG+ posts draft revisions to Functional Model for a 45-day public comment period.	May 1 to June 15, 2005
FMWG+ provides progress report to the Stakeholders Committee and the Board of Trustees.	May 2, 2005
FMWG+ presents draft outline of guide for development of regional reliability process plans to standing committees for preliminary endorsement.	Complete review by all committees by June 15, 2005
FMWG+ presents draft revisions to the Functional Model to the standing committees for comment.	Committee inputs received by June 15, 2005
NERC requests regional reliability organizations to develop regional reliability process plans for approval by standing committees in December 2005.	Issue request by July 1, 2005
FMWG+ completes analysis of committee and public comments on proposed revisions to the Functional Model.*	July 15, 2005.

FMWG+ provides a progress report to Stakeholders Committee and Board of Trustees.	August 2, 2005.
FMWG+ works jointly with regional reliability organization representatives to prepare a final guide for regional reliability process plans for approval by standing committees.	September 15, 2005
FMWG+ presents the revised Functional Model for approval of the standing committees.*	September 15, 2005
FMWG+ presents the revised Functional Model for approval by the Board of Trustees.*	November 1, 2005
FMWG+ presents to the standing committees for approval a recommended scope and membership needs for a group to continue long-term maintenance of the Functional Model. This plan addresses the process and governance for maintaining the Functional Model.	December 9, 2005
Regional reliability organizations present regional reliability process plans and updated responsible entity registrations to standing committees for approval.	December 9, 2005
NERC and regional reliability organizations implement 2006 compliance program in accordance with the regional reliability process plans.	Beginning January 1, 2006
Regional reliability process plans presented for Board approval.	February 7, 2006.

* In the event that the FMWG+ determines a second 45-day posting of the revised Functional Model is necessary, that posting would occur from August 15 to September 30, 2005. Approval would then be deferred until December 2005 by the standing committees and February 2006 by the Board.

Appendix A – Task Force Scope

Scope

The Standing Committees' Executive Committees has established the following goals for the Functional Model and Standards Coordination Task Force:

1. Review the list of issues in **Attachment 1** and prepare a concise statement of the problems to be addressed by the task force. Additional issues may be considered as long as they are within the scope of removing barriers to implementing the Functional Model in reliability standards, certification criteria, and compliance monitoring. Additional background information is provided in **Attachment 2**.
2. Investigate the technical, corporate, and regulatory impediments that hinder implementing the Reliability Authority as defined in the Functional Model. Identify the differences between the Reliability Coordinator as defined in the Version 0 standards and the Reliability Authority as defined in the Functional Model. Recommend a course of action for developing standards and certification criteria for Reliability Coordinators or Reliability Authorities, or a combination of the two.
3. Develop a recommendation for the scope and criteria for regional reliability plans that would systematically ensure that planning and operating reliability responsibilities are effectively defined, coordinated, and communicated on a continuing basis going forward.
4. For other problem areas defined in Goal 1 above, develop a recommendation to remove barriers to implementing the Functional Model in reliability standards, certification criteria and compliance monitoring. For each problem area, describe the impediments and an approach for overcoming those impediments.
5. Based on the findings above, recommend whether further changes are needed to the standards, Functional Model, certification criteria, and regional reliability plans.

Membership

The Functional Model and Standards Coordination Task Force must include members with expertise in the Reliability Functional Model, regional reliability plans, Version 0 Reliability Standards, and the criteria for certifying the Reliability Authority, Reliability Coordinator, Balancing Authority, Interchange Authority, and Transmission Operator. The membership should also include representatives from each of the 10 Regional Councils. Those members selected for their expertise in the areas listed above could also serve as the Regional Council representatives.

Reporting

The task force will report to the Technical Steering Committee.

Officers

The Standing Committees' Executive Committees will select a chairman and vice-chairman from those on the task force.

Timeline

January 19, 2005	Task force in place
February 15, 2005	Preliminary recommendations to SCEC
March 15-17, 2005	Final report to standing committees
May 2-3, 2005	Report to NERC Board of Trustees

Appendix B – Task Force Roster

Member	Organization	Region
Gerry Burrows	Kansas City Power & Light	SPP
Linda Campbell	FRCC — Florida Reliability Coordinating Council	FRCC
Dennis Chastain	TVA — Tennessee Valley Authority	SERC
Kevin Conway	Grant County Public Utility District	WECC
Jim Cyrulewski	Michigan Electric Power Coordination Center	ECAR
Mark Fidrych	WAPA — Western Area Power Administration	WECC
Scott Henry	Duke Power	SERC
Tony Jankowski	WE Energies	MAIN
Stanley Kopman	NPCC—Northeast Power Coordinating Council	NPCC
Ken Kuyper	Corn Belt Power Cooperative	MRO
Steve McCoy	California ISO	WECC
Paul McCurley	NRECA – National Rural Electric Cooperative Assn.	NA
Robert Millard	MAIN — Mid-America Interconnected Network	MAIN
Scott Moore	AEP — American Electric Power	ECAR
Steve Myers	ERCOT	ERCOT
John Norden	ISO New England	NPCC
Mike Raezer	Tucson Electric Power Company	WECC
Mike Risan	Basin Electric Power Cooperative	MRO
Karl Tammar	New York ISO	NPCC
Brian Thumm	Entergy Services	SERC
Joe Willson	PJM Interconnection	MAAC
Mike Yealland	IESO — Independent Electricity Market Operator	NPCC
Charles Yeung	SPP — Southwest Power Pool	SPP
Mike Oatts	Southern Company Services	SERC
Don Benjamin	NERC — North American Electric Reliability Council	Staff
Gerry Cauley	NERC — North American Electric Reliability Council	Staff

Appendix C – Reliability Functional Model Background

There are a few basic concepts of the Functional Model that are important to understand:

- **The model as a reflection of the industry.** The Functional Model captures the basic functions that must be performed to ensure a reliable bulk electric system, and defines each function as a collection of tasks. NERC developed the functional model because, in the mid-1990's, the traditional, vertically integrated utility was no longer the de facto organizational structure for the electricity industry. While many utilities remain vertically integrated today and will for the foreseeable future, others have unbundled their organizations or sold their generation or transmission assets to other organizations and bilateral transactions have moved from the system operators to independent and affiliate marketers. The development of Independent System Operators and Regional Transmission Organizations has resulted in the shifting of old responsibilities and the development of new responsibilities and relationships that NERC's operating policies and planning standards had never considered. As a result, NERC's reliability standards were losing their focus because they were written primarily for control areas, reliability coordinators, and regional reliability councils.

- **Loss of corporate "glue."** The obvious physical "disintegration" of the traditional control area into separate reliability and market functions and organizations has masked the more subtle loss of the corporate "glue" that once held those functions together. Confidentiality agreements and physical separations between the marketers and system operators have imposed new barriers to the coordinating interrelationships between transmission and generating operations. Because the NERC operating policies and planning standards were written for a vertically integrated organizational structure, they depended on the built-in coordination between departments or operating functions within those organizations that were inherent in their corporate structure. For example, a policy that requires the control area to operate its transmission system within NERC's first contingency criteria didn't need to specify that the operator on the transmission operator had to work with the generation dispatcher on the energy management function, or with the tariff administrator who provided transmission service to other customers. The policies assumed the utility's overall management structure would fill in those details.

  Therefore, as some vertically integrated organizations have unbundled, it isn't sufficient to only list the tasks that they used to do and bundle those tasks into functions. The industry also has to:

  - Clearly state that the tasks within a function cannot be assigned to other functions, and
  - Establish the *relationships* between and among those functions.

  This is why the Functional Model must define both the reliability functions as sets of tasks, and the interrelationships between and among the responsible entities who perform those functions and tasks.

- **Reliability Authority.** Some of the interrelationships that are defined in the Model are missing from the existing operating policies and planning standards, and hence from the Version 0 standards. Therefore, when the drafting team simply replaced the "Reliability Coordinator" with the "Reliability Authority," many people objected because their organizations were not structured to accommodate the responsibilities of the reliability authority or its interrelationship with other responsible entities as defined in the Model. Furthermore, the new reliability standards were not structured to accommodate the Reliability Authority either, but rather the Reliability Coordinator. For these reasons, the drafting team put the Reliability Coordinator in, and the left the Reliability Authority out.

- **Interchange Authority.** The Functional Model defines the Interchange Authority as the responsible entity who authorizes bilateral transactions from one Balancing Authority to another. When the Interchange Authority function was first unveiled in the Functional Model, many folks assumed that every control area would perform this function as they do today (mostly, the sink

Control Area). This led to the conclusion that the Balancing Authorities would be need to deal with more than a hundred Interchange Authorities, and the Control Area Criteria Task Force and its successor, the Functional Model Review Task Group, was deluged with comments and concerns about the impending mess this would cause.

But the Functional Model is not a physical model. The Model describes functions that must be performed, but not how to perform them.

Taking this to heart, the Operating Committee's Interchange Subcommittee is working on a plan to implement the Interchange Authority function, and is considering the merit of there being one Interchange Authority for each interconnection. Until the Interchange Subcommittee's work is complete, the Version 0 drafting team decided to leave the Interchange Authority out of the draft reliability standards for now, and assigned most of the Interchange Authority tasks to the Balancing Authorities.

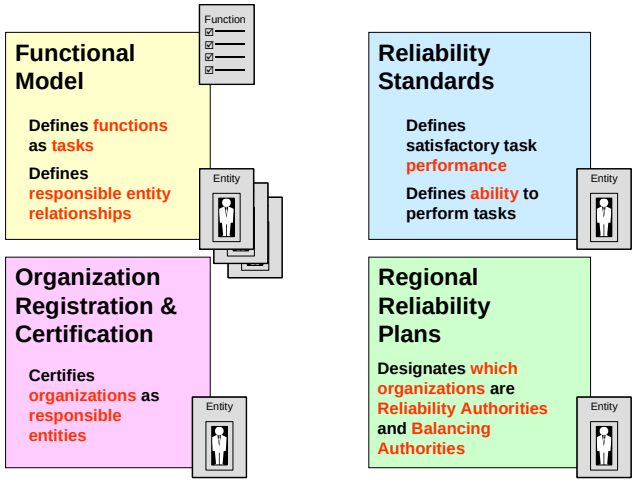
- **Functional Model Purpose.** The Functional Model is not a physical model. Its sole purpose is to identify the functions (tasks) that must be performed, and the interrelationship between the responsible entities that perform those functions.

  The Model is not intended to prescribe the physical structure of the electric industry or any organization. The hierarchy that many people have suggested between the functions (e.g., the Reliability Authority as the highest operating level) is better left to the reliability standards, regional reliability plans, and Reliability Authority certification requirements. These documents are better suited to effect the corporate structure changes, agreements, and relationships that are necessary as described in the Functional Model. The interrelationships described within the Model may not be possible within in the industry today because of constraints and boundaries imposed by state, provincial, and federal laws and tariffs.

The successful implementation of NERC's reliability standards depends on the proper interrelationship among the standards and:

- The responsible entities as defined in the Functional Model,
- The details of reliability coordination as explained in the regional operating reliability plans, and
- The organization certification requirements. (See diagram at right).

Only by reviewing all of these documents together can the course of their future development be understood.



Appendix D – Regional Reliability Process Report Guidelines

The following is a preliminary outline of guidelines for the regional reliability process plans. This outline should be further developed into a guide that the regional reliability organizations can use to develop their regional plans. The guide should be developed in partnership with the regions and should be revised periodically as experience is gained with use of the reports.

Regional reliability process plans should address the following items. In general, the report is intended to provide a broad, high-level description of reliability processes in the region. The goals of the plans are to show that there are coordinated processes to effectively achieve reliability objectives within the region, as embodied in the NERC and regional reliability standards, and to show clear accountability for compliance with those standards.

To the extent it is necessary to include critical infrastructure protection or commercially sensitive information, that information may be redacted from publicly available documents.

The plans should:

- Identify the reliability objectives of the region and how those reliability objectives are consistent with NERC and regional reliability standards.
- Include a description of the unique characteristics of the bulk electric systems that effect reliability planning and operations within the region.
- Describe the processes for reliability planning and reliable operation of the bulk electric systems in the region and how those processes are coordinated.
- Describe coordination with neighboring regions to achieve reliability planning and reliable operation of bulk electric systems.
- Identify the organizations that will be monitored for compliance with reliability standards. Initially, this list should include interconnection reliability authorities, transmission authorities, balancing authorities, interconnection planning coordinators, transmission planners, resource planners and transmission owners. The region may identify other responsible entities as needed. The list of entities requested by NERC may be modified over time as compliance monitoring needs change.
- For each identified responsible entity, indicate the bulk electric system assets over which the entity has responsibility. This may be described as an electrical footprint (bounded area) of the bulk electric system, by voltage or other class of equipment, by facility, by element, or by device. The objective is to provide sufficient detail that all assets of the bulk electric system are assigned to an identified responsible entity and that these assignments do not conflict i.e., do not have overlaps or gaps).
- Describe the interrelationships of reliability tasks performed by the identified responsible entities, including delegation of critical tasks. The objective is to demonstrate that processes are coordinated among the responsible entities and responsibilities are clearly understood among the responsible entities.
- Describe how reliability information exchange is achieved as needed to support the reliability processes described.

Appendix E – Initial Functional Registration of Responsible Entities

Entity Name	Entity Code	No. Of Functions Registered	Reliability Coordinator	Transmission Operator	Balancing Authority	Planning Authority	Transmission Planner	Regional Reliability Organization
ECAR		**75**	**3**	**18**	**16**	**18**	**19**	**1**
American Electric Power	AEP	3		X		X	X	
American Municipal Power - Ohio	AMP	0						
Allegheny Power	AP	2		X			X	
Buckeye Power Inc	BPI	0						
Big Rivers Electric Co-op	BREC	4		X	X	X	X	
Cinergy Corp	CIN	4		X	X	X	X	
Consumers Energy	CONEN	0						
Detroit Edison Company	DEC	0						
Duke Energy Fayette	DEFA	0						
Duke Energy Hanging Rock	DEHR	0						
Duke Energy Vermillion	DEVI	1			X			
Duke Energy Washington	DEWO	0						
Duquesne Light Company	DLCO	2		X			X	
The Dayton Power & Light Company	DPL	3		X		X	X	
Dynegy Generation	DYN	0						
East Central Area Reliability Coordination Agreement	ECAR	1						X
East Kentucky Power Co-op	EKPC	4		X	X	X	X	
First Energy	FE	4		X	X	X	X	
GridAmerica	GA	2				X	X	
Hoosier Energy Rural Electric Co-op	HE	4		X	X	X	X	
Indiana Municipal Power Agency	IMPA	0						
Indianapolis Power & Light Company	IPL	4		X	X	X	X	
International Transmission Company	ITC	4		X	X	X	X	
MCCP (Lansing BWL - LBWL)	LBWL	2			X	X		
LG&E Energy LLC	LGEE	3		X	X		X	
Michigan Electric Coordinated Systems	MECS	0						
Michigan Electric Transmission Co. LLC	METC	4		X	X	X	X	
Midwest ISO	MISO	2	X			X		
MCCP (Michigan Public Power Agency - MPPA)	MPPA	2			X	X		
Northern Indiana Public Service Co.	NIPS	4		X	X	X	X	
Ohio Valley Electric Corp.	OVEC	4		X	X	X	X	
PJM Interconnection	PJM	5	X	X	X	X	X	
PSEG Power LLC	PSEG	0						
Southern Indiana Gas & Electric Co.	SIGE	0						
Tennessee Valley Authority	TVA	1	X					
Vectren Energy Delivery of Indiana	VEDI	3		X	X		X	
MCCP (Wolverine Power Co-op - WPC)	WPC	3		X		X	X	

Entity Name	Entity Code	No. Of Functions Registered	Reliability Coordinator	Transmission Operator	Balancing Authority	Planning Authority	Transmission Planner	Regional Reliability Organization
Wabash Valley Power Association Inc	WVPA	0						
ERCOT		**20**	**1**	**1**	**1**	**1**	**15**	**1**
Austin Energy	AEN	1					X	
American Electric Power - ERCOT	AEPT	1					X	
Brownsville Public Utilities Board	BPUB	1					X	
Brazos Electric Coop	BRAZ	1					X	
Bryan Texas Utilities	BRYU	1					X	
City of College Station	CCS	1					X	
Centerpoint Energy	CPTE	1					X	
ERCOT ISO	ERCO	5	X	X	X	X		X
Lower Colorado River Authority TSC	LCRA	1					X	
Magic Valley Electric Cooperative	MVEC	1					X	
City Public Service Board of San Antonio	PSBSA	1					X	
Rayburn Country	RAY	1					X	
South Texas Electric Cooperatives	STEC	1					X	
City of Garland/Texas Municipal Power Authority	TMPA	1					X	
Texas New Mexico Power	TNPX	1					X	
TXU Electric Delivery	TXU	1					X	
FRCC		**70**	**1**	**15**	**11**	**21**	**21**	**1**
Beaches Energy Services of Jacksonville Beach	BES	3		X		X	X	
City of Key West	CKW	2				X	X	
City of Vero Beach	CVB	2				X	X	
Florida Keys Electric Cooperative	FKEC	3		X		X	X	
Florida Municipal Power Agency	FMPA	2				X	X	
Florida Municipal Power Pool	FMPP	1			X			
Progress Energy Florida	FPC	4		X	X	X	X	
Florida Power & Light Co.	FPL	4		X	X	X	X	
Ft. Pierce Utilities	FPU	2				X	X	
Florida Reliability Coordinating Council	FRCC	2	X					X
Gainesville Regional Utilities	GVL	4		X	X	X	X	
City of Homestead	HST	1			X			
JEA	JEA	4		X	X	X	X	
Kissimmee Utility Authority	KUA	3		X		X	X	
Lakeland Electric	LAK	3		X		X	X	
Lee County Electric Cooperative	LEEEC	3		X		X	X	
City of Lake Worth	LWU	2				X	X	
Utilities Commission of New Smyrna Beach	NSB	2		X	X			
Ocala Electric Utility	OEU	2				X	X	
Orlando Utilities Commission	OUC	3		X		X	X	
Reedy Creek Improvement District	RC	3			X	X	X	
Seminole Electric Cooperative	SEC	4		X	X	X	X	

Entity Name	Entity Code	No. Of Functions Registered	Reliability Coordinator	Transmission Operator	Balancing Authority	Planning Authority	Transmission Planner	Regional Reliability Organization
Southeastern Power Administration - FL	SEPA-FL	3		X		X	X	
City of Tallahassee	TAL	4		X	X	X	X	
Tampa Electric Company	TEC	4		X	X	X	X	
MAAC		**8**	**1**	**2**	**1**	**1**	**2**	**1**
First Energy	FE	2		X			X	
Mid Atlantic Area Council	MAAC	1						X
PJM Interconnection	PJM	5	X	X	X	X	X	
MAIN		**42**	**3**	**10**	**13**	**4**	**11**	**1**
Alliant Energy	ALT	3		X	X		X	
Alliant Energy - CA - ALTE	ALTE	1			X			
Alliant Energy - CA - ALTW	ALTW	3		X	X		X	
Ameren Transmission	AMRN	3		X	X		X	
American Transmission	ATC	3		X		X	X	
Commonwealth Edison	CE	0						
Central Illinois Light Co	CILC	0						
Central Iowa Power Cooperative	CIPC	1					X	
Columbia Water & Light	CWLD	3		X	X		X	
City Water Light & Power	CWLP	3		X	X		X	
Electric Energy, Inc.	EEI	4		X	X	X	X	
Illinois Municipal Electric Agency	IMEA	0						
Illinois Power Co.	IP	0						
Mid-America Interconnected Network	MAIN	1						X
Madison Gas and Electric Company	MGE	1			X			
Midwest ISO	MISO	2	X			X		
PJM Interconnection	PJM	5	X	X	X	X	X	
Southern Illinois Power Cooperative	SIPC	3		X	X		X	
Soyland	SOY	2		X			X	
Tennessee Valley Authority	TVA	1	X					
Upper Peninsula Power Co.	UPPC	1			X			
Wisconsin Energy Corporation	WEC	1			X			
Wisconsin Public Power Inc.	WPPI	0						
Wisconsin Public Service Corporation	WPS	1			X			
MRO		**67**	**2**	**20**	**15**	**4**	**25**	**1**
City of Ames Electric Services	AES	1					X	
Alliant Energy	ALT	0						
Basin Electric Power Cooperative	BEPC	1					X	
Corn Belt Power Cooperative	CBPC	2		X			X	
Cedar Falls Utilities	CFU	1					X	
Central Iowa Power Cooperative	CIPC	0						
Dairyland power Cooperative	DPC	3		X	X		X	
GEN~SYS Energy	GENSYS	0						
Great River Energy	GRE	3		X	X		X	
Heartland Consumers Power District	HCPD	1					X	
Hastings Utilities	HU	1					X	

Entity Name	Entity Code	No. Of Functions Registered	Reliability Coordinator	Transmission Operator	Balancing Authority	Planning Authority	Transmission Planner	Regional Reliability Organization
Iowa Association of Municipal Utilities	IAMU	1					X	
Lincoln Electric System	LES	3		X	X		X	
Montana Dakota Utilities	MDU	2		X			X	
Municipal Energy Agency of Nebraska	MEAN	0						
MidAmerican Energy Company	MEC	3		X	X		X	
Madison Gas and Electric Company	MGE	2		X	X			
Manitoba Hydro Electric Board	MHEB	4		X	X	X	X	
Midwest ISO	MISO	2	X			X		
Allete (Minnesota Power)	MP	3		X	X		X	
Minnkota Power Cooperative	MPC	2		X			X	
Muscatine Power & Water	MPW	3		X	X		X	
Missouri River Energy Services	MRES	0						
Midwest Reliability Organization	MRO	1						X
MAPP RTC	MRTC	1				X		
Morgan Stanley Capital Group, Inc	MSCG	0						
Northwestern Energy	MWE	2		X			X	
Nebraska Public Power District	NPPD	3		X	X		X	
Northern States Power Company (Xcel)	NSP	3		X	X		X	
Omaha Public Power District	OPPD	3		X	X		X	
Otter Tail Power Company	OTP	3		X	X		X	
PPM Energy Inc.	PPM	0						
Rochester Public Utilities	RPU	2		X			X	
Southern Minnesota Municipal Power Agency	SMP	3		X	X		X	
Saskatchewan	SPC	5	X	X	X	X	X	
Split Rock Energy	SRE	0						
Western Area Power Administration	WAUE	3		X	X		X	
NPCC		**49**	**5**	**11**	**6**	**7**	**19**	**1**
Northeast Power Coordinating Council	NPCC	2				X		X
MAR								
Maritime Area	MAR	0						
New Brunswick Power Transmission Corporation	NBPTC	1					X	
New Brunswick System Operator	NBSO	4	X	X	X	X		
Nova Scotia Power Incorporated	NSPI	3		X	X		X	
NE								
Bangor Hydro Electric Company	BHEC	1					X	
Boston Edison	BOSED	1					X	
Commonwealth Electric Company	CEC	0						
Cambridge Electric Light Company	CELC	1					X	
Central Maine Power Company	CMPC	1					X	
ISO New England	ISNE	5	X	X	X	X	X	
Maine Electric Power Company	MEPC	1					X	
Maine Local Control Center	MLCC	1		X				

Entity Name	Entity Code	No. Of Functions Registered	Reliability Coordinator	Transmission Operator	Balancing Authority	Planning Authority	Transmission Planner	Regional Reliability Organization
National Grid USA	NATGRID	1					X	
Northeast Utilities	NEU	2		X			X	
REMVEC Local Control Center	REMVEC	1		X				
United Illuminating Company	UNTI	1					X	
VELCO	VELCO	1					X	
NY								
Niagara Mohawk Power Corporation	NMPC	2		X			X	
New York ISO	NYIS	5	X	X	X	X	X	
ONT								
Canadian Niagara power	CANP	1					X	
Great Lakes Power	GLP	1					X	
Hydro One Networks	HONE	3		X		X	X	
The Independent Electricity System Operator	IMO	5	X	X	X	X	X	
QUE								
Hydro-Quebec TransEnergie	HQT	5	X	X	X	X	X	
SERC		**81**	**6**	**18**	**21**	**18**	**17**	**1**
SEPA - Hartwell	SEHA	0						
Southeastern Electric Reliability Council	SERC	1						X
SEPA - Ruth	SERU	0						
SEPA - Thurmond	SETH	0						
EES								
Associated Electric Cooperative, Inc.	AECI	4		X	X	X	X	
City of North Little Rock, AR	DENL	1			X			
City of Ruston, LA	DERS	1			X			
Entergy Services, Inc.	EES	5	X	X	X	X	X	
Louisiana Generating, LLC	LAGN	3		X	X	X		
SOCO								
Alabama Electric Cooperative, Inc.	AEC	4		X	X	X	X	
KGEN Enterprise, LLC	DEEM	1			X			
KGEN Murray 1, LLC - Murray 500	DEMG	1			X			
KGEN Murray II, LLC - Murray 230	DEMT	1			X			
KGEN Sandersville, LLC	DESG	1			X			
Georgia Transmission Corporation	GTC	3		X		X	X	
Municipal Electric Authority of Georgia	MEAG	2				X	X	
Southeastern Power Administration - SOU	SEPA-SOU	3		X		X	X	
South Mississippi Electric Power Association	SME	4		X	X	X	X	
Southern Company Services, Inc.	SOCO	5	X	X	X	X	X	
TVA								
Alcoa Power Generating, Inc. - Tapoco	APGI	1		X				
Batesville Control Area	BCA	1			X			
Southeastern Power Administration -	SEPA-	3		X		X	X	

Entity Name	Entity Code	No. Of Functions Registered	Reliability Coordinator	Transmission Operator	Balancing Authority	Planning Authority	Transmission Planner	Regional Reliability Organization
TVA	TVA							
Tennessee Valley Authority	TVA	5	X	X	X	X	X	
VACAR								
Progress Energy Carolinas	CPL	4		X	X	X	X	
Carolina Power & Light Company - CPLE	CPLE	0						
Carolina Power & Light Company - CPLW	CPLW	0						
Duke Power	DUK	4		X	X	X	X	
South Carolina Public Service Authority (Santee Cooper)	SC	4		X	X	X	X	
South Carolina Electric & Gas Company	SCEG	5	X	X	X	X	X	
Southeastern Power Administration - VACAR	SEPA-VAC	4		X	X	X	X	
VACAR North	VACN	1	X					
VACAR South	VACS	1	X					
Dominion Virginia Power	VAP	4		X	X	X	X	
Alcoa Power Generating, Inc. - Yadkin	YAD	4		X	X	X	X	
SPP		**60**	**1**	**18**	**17**	**3**	**20**	**1**
Arkansas Electric Coop	AECC	1					X	
Cleco Corporation	CLEC	3		X	X		X	
AEP - Central & Southwest	CSWS	4		X	X	X	X	
Empire District Electric	EDE	3		X	X		X	
Grand River Dam Authority	GRDA	3		X	X		X	
City Power & Light, Indepenence, MO	INDN	3		X	X		X	
Board of Public Utilities, Kansas City, Kansas	KACY	3		X	X		X	
Kansas City Power & Light	KCPL	2		X			X	
Kansas City Power & Light	KCPLSPS	1			X			
City of Lafayette, LA	LAFA	3		X	X		X	
Louisiana Energy & Power Authority	LEPA	1			X			
Midwest Energy	MIDW	2		X			X	
Missouri Public Service	MPS	3		X	X		X	
Oklahoma Gas & Electric	OKGE	4		X	X	X	X	
Sunflower Electric Power	SECI	3		X	X		X	
Southwestern Power Administration	SPA	3		X	X		X	
City Utilities, Springfield, MO	SPRM	2		X			X	
Southwestern Public Service - Xcel	SPS	3		X	X		X	
Southwest Power Pool	SWPP	4	X			X	X	X
Western Farmers Electric Coop	WFEC	3		X	X		X	
West Plains Energy	WPEK	3		X	X		X	
Westar	WR	3		X	X		X	
WECC		**169**	**3**	**45**	**36**	**39**	**45**	**1**
Rocky Mountain - Desert Southwest Reliability Coordinator	RDRC	1	X					
Bureau of Reclamation	USDO	0						

Entity Name	Entity Code	No. Of Functions Registered	Reliability Coordinator	Transmission Operator	Balancing Authority	Planning Authority	Transmission Planner	Regional Reliability Organization
Western Electricity Coordinating Council	WECC	1						X
AZNMSNV								
Arizona Public Service Company	AZPS	4		X	X	X	X	
Duke Energy Control Area Services, LLC	DEAA	1			X			
El Paso Electric Company	EPEC	4		X	X	X	X	
Duke Energy Control Area Services, LLC	GRMA	1			X			
Duke Energy Control Area Services, LLC	HGMA	1			X			
Imperial Irrigation District	IID	4		X	X	X	X	
Nevada Power Company	NEVP	4		X	X	X	X	
Public Service Company of New Mexico	PNM	4		X	X	X	X	
Platte River Power Autority	PRPA	3		X		X	X	
Salt River Project	SRP	4		X	X	X	X	
Tucson Electric Power	TEPC	4		X	X	X	X	
Western Area Power Administration - Desert Southwest Region	WALC	4		X	X	X	X	
CAMX								
COMISION FEDERAL DE ELECTRICIDAD	CFE	4		X	X	X	X	
California ISO	CISO	3		X	X	X		
California Mexico Reliability Coordinator	CMRC	1	X					
Los Angeles Department of Water and Power	LDWP	4		X	X	X	X	
Modesto Irrigation Distric	MID	1					X	
Pacific Gas and Electric Company	PGAE	2		X			X	
Southern California Edison Company	SCE	3		X		X	X	
San Diego Gas & Electric Company	SDGE	2		X			X	
Sacramento Municipal Utility District	SMUD	4		X	X	X	X	
The Transmision Agency of Northern California	TANC	2				X	X	
Turlock Irrigation District	TIDC	3		X	X	X		
Western Area Power Administration Sierra Nevada Region	WASN	2		X			X	
NWPP								
Alberta Electric System Operator	AESO	4		X	X	X	X	
AltaLink LP.	ALTA	1		X				
ATCO Electric Ltd.	ATCO	1		X				
Avista Utilities	AVA	4		X	X	X	X	
British Columbia Transmission Corporation (BCTC)	BCHA	4		X	X	X	X	
Bonneville Power Administration	BPAT	4		X	X	X	X	
Public Utility District #1 of Chelan County	CHPD	4		X	X	X	X	
Deseret Generation & Transmission	DGT	2				X	X	

Entity Name	Entity Code	No. Of Functions Registered	Reliability Coordinator	Transmission Operator	Balancing Authority	Planning Authority	Transmission Planner	Regional Reliability Organization
Co-operative								
PUD # 1 of Douglas County	DOPD	4		X	X	X	X	
Eugene Water & Electric Board	EWEB	2		X			X	
Grant County Public Utility District	GCPD	4		X	X	X	X	
Idaho Power Company	IPCO	4		X	X	X	X	
NorthWestern Energy	NWMT	4		X	X	X	X	
PacifiCorp - East	PACE	4		X	X	X	X	
PacifiCorp - West	PACW	4		X	X	X	X	
Portland General Electric	PGE	4		X	X	X	X	
Pacific Northwest Security Coordinator	PNSC	1	X					
Puget Sound Energy	PSEI	4		X	X	X	X	
Seattle City Light	SCL	4		X	X	X	X	
Sierra Pacific Power Company	SPPC	4		X	X	X	X	
Tacoma Power	TPWR	4		X	X	X	X	
Western Area Power Administration - Upper Great Plains Region	WAUW	4		X	X	X	X	
Fortis BC	WKPL	2		X			X	
RMPA								
BlackHills Power	BHBE	3		X		X	X	
Black Hills Generation	BHG01	3		X		X	X	
Colorado Springs Utilities	CSU	2		X			X	
Public Service Company of Colorado	PSCO	3			X	X	X	
Tri-State Generation & Transmission	TSGT	3		X		X	X	
Western Area Power Administration - WACM	WACM	4		X	X	X	X	
Aquila Inc.	WPEL	3		X	X		X	

Appendix F – Suggested Revisions to Reliability Functional Model

The edits to the Functional Model provided in this appendix are very preliminary, but provide an initial indication of how the recommendations of this report could be embodied in revisions to the model.

NERC Reliability Functional Model

Function Definitions and Responsible Entities

Version 2

Approved by Standing Committees: November 11 – 13, 2003
Approved by Board of Trustees:

Prepared by the
Functional Model Review Task Group
Planning Reliability Model Task Force

Contents

Foreword

This document replaces Version 1 of the NERC Functional Model that the Board of Trustees approved in June 2001.

* * *

Historically, Control Areas were established by vertically integrated utilities to operate their individual power systems in a secure and reliable manner and provide for their customers' electricity needs. The traditional Control Area operator balances its load with its generation, implements interchange schedules with other Control Areas, and ensures transmission reliability.

As utilities began to provide transmission service to other entities, the Control Area also began to perform the function of Transmission Service Provider through tariffs or other arrangements. NERC's Operating Policies and Standards have reflected this traditional electric utility industry structure, and ascribed virtually every reliability function to the Control Area.

Beginning in the early 1990s with the advent of open transmission access and restructuring of the electric utility industry to facilitate the operation of wholesale power markets, the functions performed by Control Areas began to change to reflect the newly emerging industry structure. These changes occurred because:

1. Some utilities were separating their transmission from their Merchant Functions (functional unbundling), and even selling off their generation,

2. Some states and provinces were instituting "customer choice" options for selecting energy providers, and

3. The developing power markets were requiring wide-area transmission reliability assessment and dispatch solutions, which were beyond the capability of many Control Areas to perform.

As a result, the ~~current~~ NERC Operating Policies in place at that time, which are centered on Control Area operations, were beginning to lose their focus, and become more difficult to apply and enforce.

The Control Area Criteria Task Force. The NERC Operating Committee formed the Control Area Criteria Task Force in 1999 to address this problem. The Task Force began by listing all the tasks required for maintaining electric system reliability and then organizing these tasks into basic groups that it called "functions." The Task Force then attempted to assign these functions to the basic "reliability organizations" such as Control Areas or Regional Transmission Organizations. But that didn't work because the Control Areas themselves were unbundling some of the functions they traditionally performed, and the emerging RTOs and ISOs, while following structures as defined in Order 2000, were not alike.

Realizing that there ~~was no longer a "standard"~~ were new reliability organizations in addition to the existing "historically standard" control area organizations, the Task Force decided to build a "Functional Model" consisting of the functions that ensure reliability and meet the needs of the marketplace. Then, organizations—whether they be traditional,

vertically-integrated control areas, regional transmission organizations, independent system operators, independent transmission companies or so on—can "roll up" those functions they perform, and register with NERC as one or more of the following: Generator Owners, Generator Operators, Transmission Service Providers, Transmission Owners, ~~Transmission Operator~~Transmission ~~s~~Authorities, Distribution Providers, Load Serving Entities, Purchasing-Selling Entities, ~~Reliability Authorities~~Interconnection Reliability Authorities, ~~Planning Authorities~~Interconnection Planning Coordinators, Balancing Authorities, ~~Interchange Authorities~~Interchange Coordinators, Transmission Planners, Resource Planners, Standards Developers, and the Compliance Monitors. The providers of functions defined in the Functional Model are called "Responsible Entities". This enables NERC to rewrite its reliability standards in terms of these -Responsible E~~e~~ntities who perform ~~the~~ certain reliability functions.

Excerpted and revised from Version 1 of the NERC Functional Model
June 12, 2001

Introduction

The NERC Functional Model defines the set of functions that must be performed to ensure the reliability of the bulk electric system. It also explains the relationship between and among the entities responsible for performing the tasks within each function. The Model provides the foundation and framework upon which NERC develops and maintains its Reliability Standards. NERC's Reliability Standards establish the requirements of the responsible entities that perform the functions defined in this Model. **The Functional Model provides the hierarchal ~~order~~relationships for authority over reliability issues ~~in that all core reliability functions "roll up" under the Reliability Authority~~.**

While the Model is not a standard, and does not have compliance requirements, the Reliability Standards must respect the definitions and interrelationships contained in the Model. Doing otherwise could result in Reliability Standards that conflict with one another.

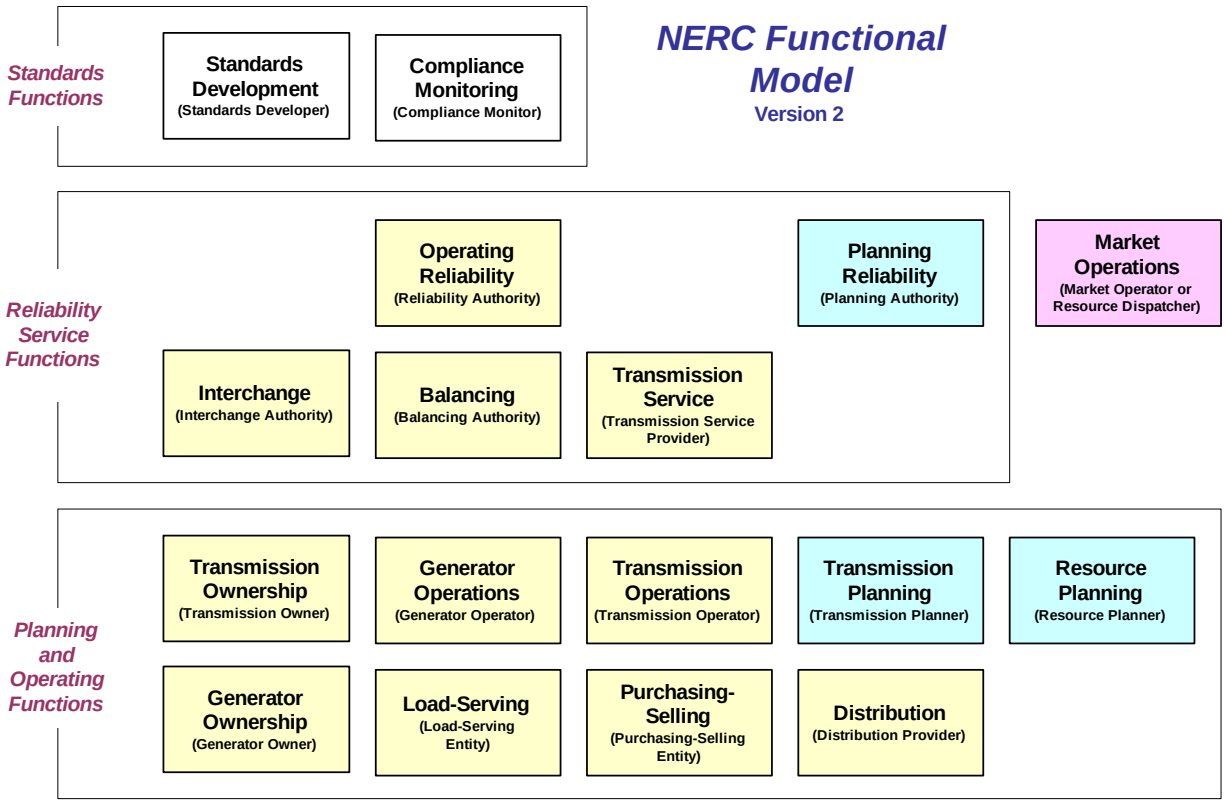
The Model does not prescribe any particular organization or market structure. Organizations may perform one or more functions as they see fit, but must recognize that some functions require the organization and its personnel to be certified to perform that function. Organizations must also recognize that, as responsible entities, they are responsible for ensuring that all tasks within each function are performed. While organizations may agree to split the tasks of a particular function (for example, an RTO may perform some ~~Transmission Operator~~Transmission Authority tasks with their members performing the remainder), NERC will require that one of the organizations be the "responsible entity," ensuring that all of the tasks of the function are performed.

The Model recognizes that the Regional ~~Councils~~Reliability Organizations and other organizations may develop reliability standards separate from the NERC Reliability Standards that are not inconsistent with the NERC Reliability Standards. Such standards may be more detailed or more stringent than the NERC Reliability Standards. The Model accommodates any organization that develops reliability standards."

Functional Model maintenance. The Functional Model is maintained by the NERC standing committees and Board of Trustees. The section titled, "Functional Model Approval Procedure," in this document explains the procedures for reviewing and revising the Model.

Technical discussions. The companion document, "Functional Model – Technical Discussions," provides additional details on the functions themselves, how organizations can "roll up" those functions they wish to perform, and how organizations as "responsible entities" interrelate.

Functional Model Diagram



Function Name	*Responsible Entity*
Operating Reliability Function	~~Reliability Authority~~Interconnection Reliability Authority
Planning Reliability Function	~~Planning Authority~~Interconnection Planning Coordinator
Balancing Function	Balancing Authority
Interchange Function	~~Interchange Authority~~Interchange Coordinator
Transmission Service Function	Transmission Service Provider
Transmission Ownership Function	Transmission Owner
Transmission Operations Function	~~Transmission Operator~~Transmission Authority
Transmission Planning Function	Transmission Planner
Resource Planning Function	Resource Planner
Distribution Function	Distribution Provider
Generator Ownership Function	Generator Owner
Generator Operations Function	Generator Operator
Load-S~~s~~erving Function	Load-S~~s~~erving Entity
Purchasing-Selling Function	Purchasing-Selling Entity
Market Operations Function	Market Operator (or Resource Dispatcher)
Standards Development Function	Standards Developer
Compliance Monitoring Function	Compliance Monitor

Terms used in the Functional Model

Areas

~~Reliability Authority~~Interconnection Reliability Authority **Area**. The collection of generation, transmission, and loads within the boundaries of the ~~Reliability Authority~~Interconnection Reliability Authority. Its boundary coincides with one or more Balancing Authority Areas.

Balancing Authority Area. The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.

Transmission Planning Area. That area under the purview of the Transmission Planner.

~~Planning Authority~~Interconnection Planning Coordinator **Area**. That area under the purview of the ~~Planning Authority~~Interconnection Planning Coordinator. It will include one or more Transmission Planning Areas.

General

Task. One of the elements that make up a Function in the Functional Model.

Responsible Entity. The label that NERC applies to a single~~n~~ organization that is directly responsible for carrying out the tasks within a Function.

Function. A group of related tasks that can not be logically subdivided into other groups.

Authority. The highest level of responsible entity for a particular function. The ~~Reliability Authority~~Interconnection Reliability Authority is the highest level of all responsible entities ~~and has the ultimate authority over all operating functions defined in the Functional Model for ensuring actions to~~ for maintaining reliability within the ~~Reliability Authority~~Interconnection Reliability Authority Area. The Balancing Authority is the highest level authority for the balancing function within its area. The Transmission Authority is the highest level authority for transmission operations within its area. It is important that the Interconnection Reliability Authority has authority to direct actions of all other entities, including the Transmission Authority and Balancing Authority, to preserve the reliability of the Interconnection.~~.~~

Transaction. An agreement arranged by a Purchasing-Selling Entity to transfer energy from a seller to a buyer.

Transmission Arrangements. An agreement between a Transmission Service Provider and Transmission Customer (Purchasing-Selling Entity, Generator Owner, Load-Serving Entity) for transmission services.

Customer. A Purchasing-Selling Entity, Generator Owner, Load-Serving Entity, or End-user.

End-use Customer. The customer served by a Load-Serving ~~Entity~~Entity which consumes energy.

Purpose of the Functional Model

The purpose of the NERC Reliability Functional Model is to:

1. Functionalize the tasks being performed today for electric system reliability so that reliability organizations such as Control Areas, Regional Transmission Organizations, Independent System Operators and others can more easily and clearly identify the reliability functions for which they are responsible~~they provide~~. A specific organization may register with NERC to be the Responsible Entity for ~~may provide~~ one or more of the functions identified in the Functional Model. This clarity of reliability function provisions should help all organizations that depend on a reliable electric system.

2. Define in general terms each function and the relationships between the Responsible Ee~~ntities who are responsible for performing the tasks within the functions. The framework for developing the function definitions is:

    a. The responsibility for performing a function should not be split by organizations – a Responsible Entity is responsibl;e for all the tasks that define the function

    b. The functions are independent of the organization structure performing the function, and

    c. The function definitions provide flexibility to accommodate the range of presently conceivable organization structures.

3. Provide a framework for Reliability Standards ~~(including organization certification criteria)~~ and compliance measures developed through the NERC Standards Development Process that will apply to certain tasks defined in the Functional Model.

    a. It is not expected that standards will be developed for each task since the Functional Model is developed in more detail than is needed for reliability standards. However, standards may contain more detail than the associated activity in the Functional Model.

    b. Responsibility for compliance with a standard will apply to the ~~organizations performing~~ Responsible Entity for that function.

    c. Other organizations developing standards may use the NERC Functional Model in the same manner.

4. Provide linkages between business practices developed by other organizations showing how certain practices may relate to the reliability functions in the Functional Model.

Guiding Principles of the Functional Model

For further details, refer to "Functions, Tasks, Responsible Entities, and Organizations" in the Technical Discussions document.

As explained in the "Purpose of the Functional Model," the Functional Model provides the framework on which the NERC reliability standards are based. To ensure that this framework remains viable, the Model itself is governed by a set of "guiding principles" that define a *function*, and establish the relationship between the *responsible entities* who are responsible for performing the *tasks* listed in the Model, and the NERC *reliability standards*. NERC must work within these guiding principles when revising or interpreting the Functional Model to maintain the integrity of the Model and NERC's Reliability Standards.

1. The Functional Model defines the *functions* that must be performed and does not imply organization structure ~~or hierarchy~~.

    a. Functions comprise *tasks*.

    b. Tasks are *what* must be done, not *how*.

2. An *organization* ~~who~~ that registers with NERC as performing a function is considered a *responsible entity* and must ensure that all tasks are performed.

    a. Reliability standards ~~are~~ identify those requirements that must be performed by *responsible entities*. Thus, we say that the Functional Model is the framework on which the reliability standards are based.

    b. An organization may delegate a task to another organization, but may not delegate its responsibility for ensuring that the task is accomplished.

    c. **The Functional Model provides the hierarchal order for authority over reliability issues ~~in that all core reliability functions "roll-up" under the Reliability Authority~~.**

3. Organizations that perform ~~certain~~ authority functions must be certified as being capable of performing those functions. Organization certification requirements are a category of NERC standards

4. Some tasks in the Functional Model may not result in a reliability standard.

Function

Function – Operating Reliability

Definition

Ensures the ~~real-time~~ operating reliability of the interconnected bulk electric transmission systems within a ~~Reliability Authority~~Interconnection Reliability Authority Area and the Interconnection ~~and with and among other Reliability Authority Areas.~~. Has ~~authority~~the responsibility and authority[1] to direct and coordinate all ~~over all~~ operating reliability functions within its area to maintain the reliability of the Interconnection.

Task~~s~~s

1. Maintain reliability of the ~~Reliability~~ Interconnection Reliability Authority Area in accordance with Reliability Standards. ~~by enforcing~~ Enforce ~~operational reliability requirements~~
2. Monitor, and record ~~as required for reliability analysis all~~ reliability-related parameters as required for reliability analysis of the Interconnection and ~~within~~ the ~~Reliability Authority~~Interconnection Reliability Authority Area~~, including generation dispatch and generation and transmission maintenance plans~~
3. Coordinate ~~Direct revisions to to~~ generation and transmission maintenance plans and direct revisions~~as required and as permitted by agreements to maintain reliability~~within the Interconnection Reliability Authority Area to maintain reliability.

~~4.Request revisions to generation maintenance plans as required and as permitted by agreements~~

~~5.~~4. Develop and communicate Interconnection Reliability Operating Limits ~~(to protect from instability, uncontrolled separations and cascading outages)~~.

~~6.~~5. Perform reliability analysis (actual, ~~and~~ contingency and post-contingency) for the ~~Reliability Authority~~Interconnection Reliability Authority Area

~~7.~~6. Assess Interchange Schedules and direct actions to protect the reliability of the Interconnection and interconnected transmission systems within a Interconnection Reliability Authority Area.~~Approve or deny bilateral schedules from the reliability perspective~~

~~8.Assist in determining Interconnected Operations Services requirements for balancing generation and load, and transmission reliability (e.g., reactive requirements, location of operating reserves).~~

~~9.~~7. Identify, communicate, and direct actions to relieve reliability operating situations~~threats~~ and reliability op~~e~~erating limit violations in the ~~Reliability Authority~~Interconnection Reliability Authority Area

~~10.~~8. Direct and coordinate implementation of emergency procedures

~~11.~~9. Direct and coordinate System Restoration

~~Ensures SDOLs are developed, monitored and followed~~

[1] Use of the term authority does not imply granting of any authority that would conflict with statutory, legal, or contractual authorities that exist with any organization.

10. Coordinate~~s~~ operations with adjoining RAs

11. ~~Develop~~Evaluate and coordinate operating plans within the Interconnection Reliability Authority Area.~~including contingency plans~~

Entity

Responsible Entity – ~~Reliability Authority~~Interconnection Reliability Authority

Relationships with other Responsible Entities

Ahead of Time

1. Receives facility and operational data from Generator Operators, Load-Serving Entities, Transmission Owners, Generator Owners, ~~Transmission Operator~~Transmission ~~s~~Authorities, Balancing Authorities, and Distribution Providers.

2. ~~Works with Transmission Owneres and Operators, Generator Owners, transmission Planners, Planning Authorities and adjoining Reliability Authorities to Calculates Interconnection Reliability Operating Limits and SOLs. And p~~Communicates the IROLs to Transmission Authorities and other Interconnection Reliability Authorities~~rovides these operating limits where needed~~.

3. Assists Transmission Authorities with the development and coordination of SOLs.

~~2.based on Transmission Owners' and Generator Owners' specified equipment ratings.~~

~~3.~~4. Receives generation dispatch from Balancing Authorities and issues dispatch adjustments to Balancing Authorities to respect operating system limits ~~mitigate congestion~~ within the ~~Reliability Authority~~Interconnection Reliability Authority Area (if not resolved through market mechanisms).

~~4.~~5. Receives Interchange Transactions from ~~Interchange Authorities~~Interchange Coordinators for reliability analysis.

~~5.Provides Interchange Transaction approvals to Interchange Authorities based on reliability analysis.~~

6. Receives generation operation plans and commitments from Balancing Authorities for reliability analysis of ~~Reliability Authority~~Interconnection Reliability Authority Area.

7. Receives generation and transmission maintenance plans from Generator operators and ~~Transmission Operator~~Transmission ~~s~~Authorities for reliability analysis of ~~Reliability Authority~~Interconnection Reliability Authority Area.

8. Directs Generator and ~~Transmission Operator~~Transmission ~~s~~Authorities to revise transmission maintenance plans as required for reliability~~and as permitted by agreements~~

9. Uses system models, coordinated with planning models, to p~~P~~rovides operating reliability analyses to ~~Transmission Operator~~Transmission ~~s~~Authorities, Generator Operators, Transmission Service Providers, ~~and~~ Balancing Authorities and Planners in its Area as well as other ~~Reliability Authorities~~Interconnection Reliability Authorities.

10. Assist in determining Interconnected Operations Services requirements for balancing generation and load, and transmission reliability (e.g., reactive requirements, location of operating reserves).

11.

Real Time

~~10.~~12. Receives real-time operational information from Balancing Authority~~, and Transmission Operator~~Transmission Authority and adjoining ~~Reliability Authorities~~Interconnection Reliability Authorities for monitoring.

~~11.~~13. Issues reliability alerts to Generator Operators, Load-Serving Entities, ~~Transmission Operator~~Transmission ~~s~~Authorities, Transmission Service Providers, Balancing Authorities, ~~Interchange Authorities~~Interchange Coordinators, ~~Planning Authorities~~Interconnection Planning Coordinators, ~~Regional Council~~Regional Reliability Organizations, and NERC.

~~12.~~14. Issues corrective actions (e.g., curtailments or load shedding) to ~~Transmission Operator~~Transmission ~~s~~Authorities, ~~Transmission Service Providers~~, Balancing Authorities, and ~~Interchange Authorities~~Interchange Coordinators.

~~13.~~15. Coordinates reliability processes and actions with and among other ~~Reliability Authorities~~Interconnection Reliability Authorities both Ahead of Time, in Real Time and post-Contingency.

~~14.~~16. Coordinates with Transmission Planners, ~~Planning Authority~~Interconnection Planning Coordinator, and Transmission Service Providers on transmission system limitations.

~~15.~~17. Coordinates with ~~Planning Authorities~~Interconnection Planning Coordinators on reliability issues, as appropriate both Ahead of Time, in Real Time and post-Contingency.~~.~~

Special Considerations

The ~~Reliability Authority~~Interconnection Reliability Authority's purview must be broad enough to enable it to calculate Interconnection Reliability Operating Limits, which may be based on the operating parameters of other transmission systems beyond ~~the~~ a single ~~Transmission Operator~~Transmission Authority's vision. ~~The~~ A single ~~Transmission Operator~~Transmission Authority may not be aware that an IROL is at risk. ~~is responsible for the reliability of its "local" transmission system, and may not be aware that its system is violating an Interconnection Reliability Operating Limit~~. Therefore, the ~~Reliability Authority~~Interconnection Reliability Authority may direct the ~~Transmission Operator~~Transmission ~~s~~Authorities or Balancing Authorities to take action to mitigate Interconnection Reliability Operating Limits.

Function

Function – Planning Reliability

Definition

Ensures a plan ~~long-term (~~generally one year and beyond~~) plan~~ is available for adequate resources and transmission within a ~~Planning Authority~~Interconnection Planning Coordinator Area. It integrates and assesses the plans from the Transmission Planners and Resource Planners within the ~~Planning Authority~~Interconnection Planning Coordinator Area to ensure those plans meet the reliability standards, and develops ~~and recommends solutions~~ corrective actions f~~t~~or plans that do not meet those standards.

Tasks

1. Develop and maintain transmission and resource (demand and capacity) system models to evaluate transmission system performance and resource adequacy.
2. Maintain and develop~~apply~~ methodologies and tools for the analysis and simulation of the transmission systems in the assessment and development of transmission expansion plans and the analysis and development of resource adequacy plans.
3. Define~~, and~~ collect or develop and share information required for planning purposes, including:
    a. Transmission facility characteristics and ratings,
    b. Demand and energy ~~end-use customer~~ forecasts, capacity resources, and demand response programs,
    c. Generator unit performance characteristics and capabilities, and
    d. Long-term capacity purchases and sales.
4. Evaluate plans for customer requests for transmission service.
    a. Evaluate responses to long-term (generally one year and beyond) transmission service requests.
    b. Review transmission facility plans required to integrate new (end-use customer, generation, and transmission) facilities into the interconnected bulk electric systems.
5. Review and determine TTC, IROL and SOL values (generally one year and beyond) as appropriate.
6. Assess, develop, ~~and~~ document and report on resource and transmission expansion plans.
    a. Integrate and verify that the respective plans for the ~~Planning Authority~~Interconnection Planning Coordinator Area meet reliability standards.
    b. Identify and report on potential transmission system and resource adequacy deficiencies, and provide alternate plans that mitigate these deficiencies.

~~7.Provide analyses and reports as required on the long-term resource and transmission plans for the Planning Authority Area.~~

~~8.~~7. Monitor transmission expansion plan and resource plan implementation.

~~9.~~8. Coordinate projects requiring transmission outages that can impact reliability and firm transactions.

~~10.~~9. Evaluate the impact of revised transmission and generator in-service dates on resource and transmission adequacy.

11.Work with adjoining ~~Planning Authorities~~Interconnection Planning Coordinators so that system models and resource and transmission expansion plans take into account modifications made to networks in adjacent ~~Planning Authority~~Interconnection Planning Coordinator Areas.

Responsible Entity – ~~Planning Authority~~Interconnection Planning Coordinator

Relationships with other Responsible Entities

1. Collects information as appropriate, including:

    a. Transmission facility characteristics and ratings from the Transmission Owners, Transmission Planners, ~~Transmission Operator~~Transmission ~~s~~Authorities, and others.

    b. Demand and energy ~~end-use customer~~ forecasts, capacity resources, and demand response programs from Load-Serving Entities and Resource Planners.

    c. Generator unit performance characteristics and capabilities from Generator Owners and others.

    d. Long-term capacity purchases and sales from Transmission Service Providers.

2. Receives TSP's ~~requests for long-term~~ transmission service requests sent to the ~~from~~ Transmission Planners and provides the resulting plans to Transmission Service Providers, Transmission Plannerrs and Operators and Transmission Owners.

3. Provides transmission facility plans required to integrate new (end-use customer, generation, and transmission) facilities into the interconnected bulk electric systems to the Transmission Owners, Generator Owners, Transmission Planners and other requesters.

4. Coordinates TTC, IROL and SOL values (generally one year and beyond) with Transmission Planners, ~~Reliability Authority~~Interconnection Reliability Authority, Transmission Owner and Operatror, Transmission Service Provider and neighboring ~~Planning Authorities~~Interconnection Planning Coordinators.

5. Integrates and verifies that the respective plans of the Resource Planners and Transmission Planners meet reliability standards, and ~~.~~ develops corrective actions for plans that do not meet those standards.

~~5.~~

6. Coordinates the plans for the interconnection of facilities[2] to the bulk electric systems within its ~~Planning Authority~~Interconnection Planning Coordinator Area with Transmission Planners and Resource Planners.

7. Coordinates as appropriate with resource suppliers outside of the ~~Planning Authority~~Interconnection Planning Coordinator Area.

[2] Generators, transmission lines, and end-use customer equipment

8. Coordinates transmission system protection and control, including special protection systems, with Transmission Planners, other ~~Planning Authorities~~Interconnection Planning Coordinators, Generator Owners, Generator Operators, Transmission Owners, ~~Transmission Operator~~Transmission ~~s~~Authorities, ~~Reliability Authorities~~Interconnection Reliability Authorities, and Distribution Providers.

9. Coordinates with its related ~~Reliability Authority~~Interconnection Reliability Authority(ies) and other ~~Planning Authorities~~Interconnection Planning Coordinators on reliability issues, as appropriate.

Function

Function – Balancing

Definition

Integrates resource plans ahead of time, keeps actual interchange equal to its scheduled interchange and provides frequency bias obligation for its Balancing Authority Area~~and maintains load-interchange-generation balance within a Balancing Authority Area and supports Interconnection frequency~~ in real time.

Tasks

1. Must have control of any of the following combinations within a Balancing Authority Area:
    a. Load and Generation (an isolated system)
    b. Load and Scheduled Interchange
    c. Generation and Scheduled Interchange
    d. Generation, Load, and Scheduled Interchange
2. Calculate Area Control Error within the Balancing Authority Area.
3. Review generation commitments, dispatch, and load forecasts.
4. Formulate an operational plan (generation commitment, outages, etc) for reliability assessment
5. Approve Interchange Transactions from ramping ability perspective
6. Implement interchange schedules by entering those schedules into an energy management system for both AC systems and DC Ties
7. Provide frequency response
8. Monitor and report control performance and disturbance recovery
9. Provide balancing and energy accounting (including hourly checkout of Interchange Schedules and Actual Interchange), and administer Inadvertent energy paybacks
10. Determine needs for Interconnected Operations Services
11. Deploy Interconnected Operations Services.
12. Implement emergency procedures

Responsible Entity – Balancing Authority

Relationships with other Responsible Entities

Ahead of Time

1. Compiles load forecasts from Load-Serving Entities.
2. Receives operational plans and commitments for the Balancing Authority Area from Generator Operators (or Market Operator) ~~within the Balancing Authority Area~~
3. Determines amount required and deploys Interconnected Operations Services to ensure balance (e.g., amount of operating reserve, load-following, frequency response) in coordination with the ~~Reliability Authority~~Interconnection Reliability Authority.
4. Submits integrated operational plans (including maintenance plans from Generator Operators) to the ~~Reliability Authority~~Interconnection Reliability Authority for reliability assessment and provide balancing information to the ~~Reliability Authority~~Interconnection Reliability Authority for monitoring.
5. Receives approved, valid, and balanced Interchange Schedules from the ~~Interchange Authorities~~Interchange Coordinators.
6. Confirms interchange schedules with ~~Interchange Authorities~~Interchange Coordinators.
7. Confirms ramping capability with ~~Interchange Authorities~~Interchange Coordinators.
8. Implements generator commitment and dispatch schedules from the Load-Serving Entities and Generator Operators who have arranged for generation within the Balancing Authority Area. The Balancing Authority provides this commitment and dispatch schedule to the ~~Reliability Authority~~Interconnection Reliability Authority.
9. Provides generation dispatch to its ~~Reliability Authority~~Interconnection Reliability Authority for reliability analysis.
10. Acquires Interconnected Operations Services from Generator Owners.

Real Time

11. Directs resources (Generator Operators and Load-Serving Entities) to take action to ensure balance in real time.
12. Directs ~~Transmission Operator~~Transmission Authority to reduce voltage or shed load if needed to ensure balance within its Balancing Authority Area.
13. Receives loss allocation from Transmission Service Providers (for repayment with in-kind losses).
14. Provides real-time operational information for ~~Reliability Authority~~Interconnection Reliability Authority monitoring.
15. Complies with reliability requirements specified by ~~Reliability Authority~~Interconnection Reliability Authority.
16. Informs ~~Reliability Authority~~Interconnection Reliability Authority and ~~Interchange Authorities~~Interchange Coordinators of Interchange Schedule

interruptions (e.g., due to generation or load interruptions) within its Balancing Authority Area.

17. Directs Generator Operators to implement redispatch for congestion management as directed by the ~~Reliability Authority~~Interconnection Reliability Authority.
18. Requests operating information from Generator Operators.
19. Verifies implementation of emergency procedures to ~~Reliability Authority~~Interconnection Reliability Authority.
20. Coordinates use of controllable loads with Load Serving Entities (i.e., interruptible load that has been bid in as Interconnected Operations Services).
21. Implements emergency procedures as directed by the ~~Reliability Authority~~Interconnection Reliability Authority.

After the hour

22. Confirms Interchange Schedules with ~~Interchange Authorities~~Interchange Coordinators after the hour for "checkout."
23. Confirms Actual Net Interchange with adjacent Balancing Authorities after the hour for "checkout."

Function

Function – Market Operations

Definition

Integrates energy, capacity, balancing, and transmission resources to achieve an economic, reliability-constrained dispatch of resources. The dispatch may be either cost-based or bid-based.

Tasks

1. Administer a market that provides capacity, energy, balancing resources, and other Ancillary Services subject to system requirements and constraints.

2. Arrange resources for congestion management.

3. Provide dispatch plans.

Special Considerations

The Market Operations function, its tasks, and the interrelationships with other entities is included in the Functional Model only as an interface point with other types of industry models.

Responsible Entity – Market Operator (or Resource Dispatcher)

Relationships with other Responsible Entities

Market Operator tasks and relationships are specific to a particular Market Operator and will depend on the market structure over which the Market Operator presides.

The Resource Dispatcher performs the same dispatch duties of~~as~~ the Market Operator, but in a non-market environment.

Making Deals

1. **Approves or denies Market Transaction requests from Purchasing-Selling Entities, Generator Owners, and Load-Serving Entities based on market clearing.**

Ahead of Time

2. **Provide individual commitment plans to Generators Operators**

Provide operational plans and generation commitment to the Balancing Authority

Function

Function – Resource Planning

Definition

Develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a ~~Planning Authority~~Interconnection Planning Coordinator Area.

Tasks

1. Maintain resource models and apply appropriate tools for the development of adequate resource plans.

2. Define and collect or develop demand and resource information required for planning purposes.

3. Provide capacity resource information to planning and operating functions and service functions.

4. Assist in the evaluation of the deliverability of resources to customers.

5. Include consideration of generation capacity from resources both within and outside of the ~~Planning Authority~~Interconnection Planning Coordinator Area.

6. Develop and report, as appropriate, on its resource plans to others for assessment and compliance with reliability standards.

7. Monitor and report, as appropriate, on its resource plan implementation.

Entity

Responsible Entity – Resource Planner

Relationships with other Responsible Entities

1. Coordinates the resource models with its ~~Planning Authority~~Interconnection Planning Coordinator.

2. Works and coordinates with Transmission Owners and Transmission Planners on the deliverability of resources to customers.

3. Reports its resource plan to the ~~Planning Authority~~Interconnection Planning Coordinator for assessment and compliance with reliability standards.

4. Reports on resource plan implementation to the ~~Planning Authority~~Interconnection Planning Coordinator.

5. Works with ~~Planning Authority~~Interconnection Planning Coordinator and Transmission Planners to identify potential alternative solutions to meet resource requirements.

6. Coordinates with and collects data for resource planning from the Load-Serving Entities, Generator Owners, Generator Operators, Transmission Owners, ~~Transmission Operator~~Transmission ~~s~~Authorities, and ~~Interchange Authorities~~Interchange Coordinators.

7. Coordinates with Transmission Planners, Transmission Service Providers, ~~Reliability Authorities~~Interconnection Reliability Authorities, and ~~Planning Authorities~~Interconnection Planning Coordinators on resource adequacy plans as appropriate.

8. Coordinates with other Resource Planners within the ~~Planning Authority~~Interconnection Planning Coordinator Area to avoid the double-counting of resources.

Special Considerations

In some markets, it may be required that the same entity perform the Resource Planning Function and the ~~Planning Authority~~Interconnection Planning Coordinator Function. For example, the Resource Planner may also be the ~~Planning Authority~~Interconnection Planning Coordinator in those markets where there are no entities responsible or obligated to serve load. In these cases, the Resource Planning Function becomes a resource assessment function performed by the ~~Planning Authority~~Interconnection Planning Coordinator that identifies the need for additional resources to be provided by the market.

Function

Function – Transmission Operations

Definition

Ensures the reliability of the bulk electric transmission system within a Transmission Authority Area. Has the responsibility and authority to direct and coordinate the operation of transmission facilities within its area to maintain the reliability of the bulk electric system.. ~~Operates or directs the operations of the transmission facilities.~~

Tasks

1. Develop transmission operating and contingency plans and operate the system to ensure the reliability of the area in accordance with ~~NERC~~ Reliability Standards ~~and defined operatong limits~~.

~~1.~~2. Determine and communicate System Operating Limits.

3. Monitor and perform reliability analysis of the Transmission Authority Area. ~~Maintain reliability of the transmission area in accordance with Reliability Standards.~~

~~2.~~4. Implement~~Provide~~ detailed transmission maintenance schedules (dates and times) provided by the Transmission Owner

~~3.~~5. Adjust dc ties and phase shifters within the transmission area for those Interchange Transactions that include ~~the dc tie~~these facilities in the transmission path

~~4.~~6. Deploys reactive resources to m~~M~~aintain voltages within defined ~~voltage profiles~~limits.

5. ~~Contribute to the development of facility ratings and operating Define operating limits, develop contingency plans, and monitor operations of the transmission facilities.~~

~~6.~~7. Provide telemetry of transmission system information in real time and historical operating information as required

8. ~~.~~Coordinate operations plans, reliability analysis, and operations with the Interconnection Reliability Authority, Balancing Authority, and other ~~Transmission Operator~~Transmission ~~s~~Authorities

9. Implement reliability measures as directed by the ~~Reliability Authority~~Interconnection Reliability Authority

10. Requests the Balancing Authority to adjust generation dispatch to relieve System Operating Limit violations.

11. Approve or deny Interchange Schedules from a reliability perspective.

12. Develop and implement emergency procedures.

13. Develop and implement System Restoration Plan.

Entity

Responsible Entity – ~~Transmission Operator~~Transmission Authority

Relationships with other Responsible Entities

Ahead of Time

1. Receives maintenance requirements and plans from the Transmission Owner and generator operating plans as needed for coordination from the ~~Reliability Authority~~Interconnection Reliability Authority.

2. Defines operating limits, develops contingency plans, and monitors operations of the transmission facilities under the ~~Transmission Operator~~Transmission Authority's control and as directed by the ~~Reliability Authority~~Interconnection Reliability Authority.

3. Provides operating information to the ~~Reliability Authority~~Interconnection Reliability Authority.

4. Determines amount required and arranges for interconnected operations services from Generator Owners to ensure voltage support (e.g., reactive supply from generation resources) ~~in coordination with~~under the general direction of the ~~Reliability Authority~~Interconnection Reliability Authority.

5. Provides maintenance schedules and construction plans to ~~Reliability Authority~~Interconnection Reliability Authority and ~~Planning Authority~~Interconnection Planning Coordinator.

6. Revises transmission maintenance plans as ~~requested~~ required by the ~~Reliability Authority~~Interconnection Reliability Authority ~~and as permitted by agreements,~~ recognizing that equipment maintenance must be performed as needed to ensure the life of the equipment and meet warranty requirements.

7. Provides ~~Planning Authority~~Interconnection Planning Coordinator information on capability to curtail (reduce) and shed load during emergencies.

8. Maintains and uses system modeling tools for planning and analysis that are coordinated with the ~~Reliability Authority~~Interconnection Reliability Authority, Transmission Planner and ~~Planning Authority~~Interconnection Planning Coordinator.

9. Coordinate operating, contingency and emergency plans with others.

10. Contribute to the development of facility ratings and operating limits

Real Time

~~8.~~11. Operates or directs the operations of the transmission system within equipment and facility ratings ~~-~~established by the Transmission Owners and Generator Owners, ~~Reliability Authority~~Interconnection Reliability Authority, Thansmission Planner and ~~Planning Authority~~Interconnection Planning Coordinator and system ~~ratings~~ limits established by the ~~Reliability~~

~~Authority~~Interconnection Reliability Authority, ~~Transmission Operator~~Transmission Authority, Transmission Planner and ~~Planning Authority~~Interconnection Planning Coordinator.

~~9.~~12. Deploys reactive resources from Transmission Owners and Generator Owners as Interconnected Operations Services to maintain acceptable voltage profiles.

~~10.~~13. Provides real-time operations information to the ~~Reliability Authority~~Interconnection Reliability Authority.

~~11.~~14. Notifies Generator Operators of transmission system problems (e.g., voltage limitations or equipment overloads that may affect generator operations).

~~12.~~15. Requests ~~Reliability Authority~~Interconnection Reliability Authority to mitigate equipment overloads. (e.g., redispatch, transmission loading relief).

~~13.~~16. Coordinates load shedding with, or as directed by, the ~~Reliability Authority~~Interconnection Reliability Authority.

~~14.~~17. Directs Distribution Providers to shed load in response to the ~~Reliability Authority~~Interconnection Reliability Authority, Transmission ~~o~~Operator or ~~b~~Balancing Authority..

~~15.~~18. Implements dc tie operations for those ties under the ~~Transmission Operator~~Transmission Authority's purview as directed by the ~~Transmission Service Provider~~~~Interchange Authority~~Interchange Coordinator.

19. Reports compliance information to Compliance Monitor

20. Provides historical operating data to others as required

Function

Function – Interchange

Definition

Receives approvals and communicates authorization to ~~Authorizes~~ implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures Interchange Transactions are properly identified for reliability assessment purposes.

Tasks

1. Determine valid, balanced, Interchange Schedules (validation of sources and sinks, transmission arrangements, interconnected operations services, etc.).

2. Verify ramping capability of the source and sink Balancing Authority Areas for requested Interchange Schedules

3. Collect and disseminate Interchange Transaction approvals, changes, and denials

4. Authorize implementation of Interchange Transactions **over both AC and DC interfaces**

5. Enter Interchange Transaction information into Reliability Assessment Systems (e.g., the Interchange Distribution Calculator in the Eastern Interconnection)

6. Maintain record of individual Interchange Transactions

Entity

Responsible Entity – ~~Interchange Authority~~Interchange Coordinator

Relationships with other Responsible Entities

Ahead of Time

1. Verifies ramping capability for requested Interchange Schedules with Balancing Authorities.

2. Receives requests from Purchasing-Selling Entities to implement Interchange Transactions.

3. Submits all Interchange Transaction requests to the ~~Reliability Authorities~~Interconnection Reliability Authorities, Balancing Authorities, and Transmission Service Providers for approvals.

4. Receives confirmation from Transmission Service Providers of transmission arrangement(s).

5. Recieves confirmation of the reliability assessment from the ~~Reliability Authority~~Interconnection Reliability Authority(ies)

~~5.~~6. Receives confirmation from Balancing Authorities of the ability to meet ramping requirements for submitted Interchange Schedules.

~~6.~~7. Receives information from Balancing Authorities of expected Interconnected Operations Services deployments that result in an Interchange Transaction (for example, an Interchange Schedule that is enabled by reducing load in a Balancing Authority Area, which frees up resources.)

~~7.~~8. Informs Purchasing-Selling Entities on implementation of load-provided Interconnected Operations Services that were bid into the market that result in an Interchange Transaction.

~~8.~~9. Provides approved, valid, and balanced Interchange Schedules to the Balancing Authorities for implementation.

10. Receives curtailments and redispatch implementation from ~~Reliability Authorities~~Interconnection Reliability Authorities.

Real Time

~~9.~~11. Provides Transmission Service Providers with the requested Interchange Transactions received from Purchasing Selling Entities using that Transmission Service Providers' transmission system.

~~10.~~12. Receives curtailments and redispatch implementation from ~~Reliability Authorities~~Interconnection Reliability Authorities. Moved to Ahead of Time.

~~11.~~13. Informs Transmission Service Providers, Purchasing-Selling Entities, ~~Reliability Authorities~~Interconnection Reliability Authorities, and Balancing

Authorities of Interchange Schedule Implementations and Curtailments after being notified by the ~~Reliability Authority~~Interconnection Reliability Authority.

~~12.~~14. Receives information on Interchange Schedule interruptions due to generation loss or load interruption from the Balancing Authorities.

After the hour

~~13.~~15. Maintains and provides records of individual Interchange Transactions for the Balancing Authorities.

Function

Function – Transmission Planning

Definition

Develops a ~~long-term (~~plan (generally one year and beyond) ~~plan~~ for the reliability ~~(adequacy)~~ of the interconnected bulk electric transmission systems within its portion of the ~~Planning Authority~~Interconnection Planning Coordinator Area

~~*Tasks*~~

~~Develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within a portion of the Planning Authority Area.~~

Tasks

1. Maintain transmission system models (steady-state, dynamics, and short circuit) for analysis and simulation of and apply appropriate tools for the development of transmission plans and the reliability assessment of current facilities.

2. Define and collect transmission information and transmission facility characteristics and ratings.

3. Develop expansion plans that support reliable and safe operation of the electric facilities while respecting voltage and stability limits and facility thermal ratings ~~Develop plans within defined voltage and stability limits and within appropriate facility thermal ratings.~~

4. Define system protection and control needs and requirements, including special protection systems (remedial action schemes), to meet reliability standards.

5. Work with the ~~Planning Authority~~Interconnection Planning Coordinator to d~~D~~etermine TTC values[3] as appropriate.

6. Notify others of any planned transmission changes that may impact their facilities.

7. Evaluate and plan for all interconnection requests and transmission service ~~and interconnection~~ requests beyond one year.

8. Develop and report, as appropriate, on its transmission expansion plan for assessment and compliance with reliability standards.

9. Monitor and report, as appropriate, on its transmission expansion plan implementation.

10. Support the development of IROL and SOL

[3] TTC is the total transfer capability and refers to the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions.

Entity

Responsible Entity – Transmission Planner

Relationships with other Responsible Entities

1. Provides transmission information, as appropriate, to planning and operating entities and service entities.

2. Coordinates and collects data as appropriate for system modeling, and plans transmission system modifications and expansion for Load-Serving Entities, Generator Owners, and Distribution Providers with other Transmission Planners, Transmission Owners, ~~Transmission Operator~~Transmission ~~s~~Authorities, and Transmission Service Providers.

    a. Coordinates its transmission models with its ~~Planning Authority~~Interconnection Planning Coordinator.

    b. Notifies Generator Owners and Transmission Owners of any planned transmission changes that may ~~impact~~ affect the operation of their facilities.

    c. Coordinates with Resource Planners on the deliverability of new and proposed generation facilities, as appropriate.

3. Coordinates with Transmission Service Providers, Transmission Owners, ~~Reliability Authorities~~Interconnection Reliability Authorities, ~~Planning Authorities~~Interconnection Planning Coordinators, Resource Planner and other Transmission Planners on system limitations, transmission adequacy plans, and the determination of TTC values as appropriate.

4. Coordinates with its ~~Planning Authority~~Interconnection Planning Coordinator, other ~~Planning Authorities~~Interconnection Planning Coordinators, and other Transmission Planners within its ~~Planning Authority~~Interconnection Planning Coordinator Area on reliability issues, as appropriate, including

    a. Develops and reports its transmission expansion plan to its ~~Planning Authority~~Interconnection Planning Coordinator for assessment and compliance with reliability standards.

    b. Works with its ~~Planning Authority~~Interconnection Planning Coordinator to identify potential alternative solutions, including solutions proposed by stakeholders, to meet interconnected bulk electric system requirements.

    c. Reports on transmission expansion plan implementation to its ~~Planning Authority~~Interconnection Planning Coordinator.

    5.Coordinate with TSP to evaluate and plan for transmission service and interconnection requests beyond one year.

Function

Function – Transmission Service

Definition

Administers the transmission tariff. Provides transmission services to qualified market participants under applicable transmission service agreements (for example, the *pro forma* tariff).

Tasks

1. Receive transmission service requests and process each request for service according to the requirements of the tariff.

    a. Maintain commercial interface for receiving and confirming requests for transmission service according to the requirements of the tariff (e.g., OASIS).

2. Approve or deny transmission service requests

3. Approve Interchange Transactions from transmission service arrangement perspective

4. Determine and post available transfer capability (ATC[4]) values.

5. Allocate transmission losses (MWs or funds) among Balancing Authority Areas.

6. coordinate with Transmission Planner and ~~Planning Authority~~Interconnection Planning Coordinator to develop plans to accommodate transmission service requests that cannot be accommodated with existing planned facilities.

[4] In this document, we use the term "ATC" in the generic sense to refer to the amount of transmission transfer capability that is offered under regulatory requirements.

Responsible Entity – Transmission Service Provider

Relationships with other Responsible Entities

Making Deals

1. Approves or denies transmission service requests from Purchasing-Selling Entities, Generator Owners, and Load-Serving Entities

Ahead of Time

2. Receives transmission expansion plans identified by the ~~Planning Authority~~Interconnection Planning Coordinator and IROL,SOL and TTC to help determine ability to accommodate long-term transmission service requests

3. Coordinates ATC with ~~Reliability Authority~~Interconnection Reliability Authority (who may adjust operating reliability limits) and other Transmission Service Providers

4. Confirms Transmission Service requests to ~~Interchange Authorities~~Interchange Coordinators.

Real Time

5. Receives Interchange Transaction implementation and revisions from the ~~Interchange Authorities~~Interchange Coordinators

Function

Function – Transmission Ownership

Definition

Owns and maintains transmission facilities.

Tasks

1. Install and maintain transmission facilities according to ~~prudent~~ good utility practice

2. Establish ratings of transmission facilities.

3. Develops interconnection and operating agreements consistent with NERC Reliability Standards.

4. Implement transmission expansion plans

Responsible Entity – Transmission Owner

Relationships with other Responsible Entities

1. Coordinates with Transmission Planners and the ~~Planning Authority~~Interconnection Planning Coordinator and those entities (Generator Owners, other Transmission Owners, and Load-Serving Entities) desiring to interconnect facilities with the bulk electric systems.

2. Considers for implementation, transmission expansion plans identified by the ~~Planning Authority~~Interconnection Planning Coordinator

3. Provides transmission expansion plans and changes to the ~~Planning Authority~~Interconnection Planning Coordinator and Transmission Planners.

4. Develops agreements or procedures with the Transmission Service Providers.

5. Develops operating agreements or procedures with the ~~Transmission Operator~~Transmission ~~s~~Authorities and ~~Reliability Authorities~~Interconnection Reliability Authorities.

6. Provides transmission facility ratings to ~~Transmission Operator~~Transmission ~~s~~Authorities, ~~Reliability Authorities~~Interconnection Reliability Authorities, Transmission Service Providers, Transmission Planners, and ~~Planning Authority~~Interconnection Planning Coordinator.

7. Provides construction plans to the ~~Reliability Authority~~Interconnection Reliability Authority and ~~Planning Authority~~Interconnection Planning Coordinator

8. Provides facility maintenance ~~plans~~ plans and vegetation control and ROW management plans to the ~~Transmission Operator~~Transmission Authority.

9. Develops agreements with adjacent Transmission Owners for the design, construction, ~~and~~ operation and maintenance of joint transmission facilities.

Function

Function – Distribution

Definition

Provides and operates the "wires" between the transmission system and the end-use customer.

Tasks

1. Provide the interface between the transmission system and the end-use customer.
2. Provide voltage reduction and load shedding as necessary
3. Provide demand forecast data and real time metering data.
4. maintain power factor obligations

Responsible Entity – Distribution Provider

Relationships with other Responsible Entities

Ahead of Time

1. Coordinates with Load-Serving Entities, Transmission Planners and their related ~~Planning Authority~~Interconnection Planning Coordinator on transmission expansion (e.g., coordination of system protection, special protection systems, load shedding, etc).

2. Works with end-use customers to identify new facility connection needs.

3. Provide demand forecast data to the ~~Reliability Authority~~Interconnection Reliability Authority and ~~Planning Authority~~Interconnection Planning Coordinator.

Real Time

~~3.~~4. Implements voltage reduction and sheds load as directed by ~~Transmission Operator~~Transmission ~~s~~Authorities and Balancing Authorities

5. Provide operating and historical data as required.

Special Considerations

The Distribution Provider provides the physical connection between the end-use customer and the electric system. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage.

The Distribution Provider is responsible for “local” safety and reliability. The Distribution Provider knows which customers are “critical” loads that should be shed only as a last resort, and provides the switches and reclosers for this emergency action.

Function

Function – Generator Operation

Definition

Operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services.

Tasks

1. Operate generators to provide energy or Interconnected Operations Services (or both) per contracts or arrangements
2. Formulate daily generation plan
3. Report operating and availability status of units and related equipment, such as automatic voltage regulators.
4. Develop annual maintenance plan for generating units and performs the day-to-day generator maintenance
5. Provides voltage support to ~~Transmission Operator~~Transmission ~~s~~Authorities

Responsible Entity – Generator Operator

Relationships with other Responsible Entities

Ahead of Time

1. Provides generation commitment plans to the Balancing Authority or Market Operator after notification by Purchase-Selling Entities or Load Serving Entities of transaction approvals.
2. Provides Balancing Authority and ~~Transmission Operator~~Transmission Authority with requested amount of Interconnected Operations Services.
3. Provides operating and availability status of units to ~~Reliability Authority~~Interconnection Reliability Authority and Balancing Authority for reliability analysis.
4. Reports annual maintenance plan for generating units to Balancing Authority and ~~Transmission Operator~~Transmission Authority.
5. Reports status of automatic voltage regulators to ~~Transmission Operator~~Transmission ~~s~~Authorities.
6. Provides long-term unit maintenance schedules and unit retirement plans to Resource Planner and ~~Planning Authority~~Interconnection Planning Coordinator.

Real Time

7. Follows generation dispatch as directed by Balancing Authority.or Market Operator~~Implements, upon direction by Balancing Authority, redispatch and interchange schedules~~
8. Provides real-time operating information to the ~~Transmission Operator~~Transmission Authority and Balancing Authority (to both the “host” Balancing Authority in which the Generator is physically located and the sink Balancing Authority in case the generation is dynamically transferred between Balancing Authority Areas).

Function

Function – Generator Ownership

Definition

Owns and maintains generating units.

Tasks

1. Establish generating unit ratings, limits and operating requirements.
2. Maintain its generation facilities according to ~~prudent~~ good utility practices.
3. Verify generating unit performance characteristics

Responsible Entity – Generator Owner

Relationships with other Responsible Entities

1. Provides generator ratings, limits, and models to Transmission Planners and ~~Planning Authorities~~Interconnection Planning Coordinators and updates with any changes.

Real Time

2. May deal directly[5] with either Load Serving Entities or Purchase-Selling Entities via bilateral contracts for energy, capacity, and Interconnected Operations Services ~~products~~

~~3.Provides voltage support to Transmission Operators~~

[5] The Generator Owner can serve as its own Purchasing-Selling Entity, or be affiliated with a Load-Serving Entity.

Function

Function – Purchasing-Selling

Definition

Purchases or sells energy, capacity and all necessary Interconnected Operations Services as required. Purchasing-Selling Entities may be Marketers or Merchant Affiliates.

Tasks

1. Purchase and sell generation or capacity
2. Arrange Interchange Transactions
3. Arrange for transmission service (as required by tariffs)
4. Purchase and sell Interconnected Operations Services
5. Request implementation of Interchange Transactions

Responsible Entity – Purchasing-Selling Entity

Relationships with other Responsible Entities

Making Deals

1. Assists Load Serving Entities (LSE) in defininge Interchange Transactions ~~in~~to meet~~ing~~ the LSE's needs.
2. Assists Load Serving Entities and other Purchasing-Selling Entities in supplying the Interconnected Operations Services needs of the Load-Serving Entities. (e~~E~~.g., supplying regulation service via Interchange Transactions).
3. Arranges for transmission service from Transmission Service Providers and makes arrangements for Interconnected Operations Services with Generator Owners or Load-Serving Entities as applicable for Interchange Transactions.
4. **Submits Market Transaction Requests to the Market Operator (whereapplicable).**

Transaction Approval and Plans Ahead of Time

~~4.~~5. Submits requests to ~~Interchange Authorities~~Interchange Coordinators to implement Interchange Transactions.

~~5.~~6. Notifies Market Operator (where applicable), Generator Operators and Load Serving Entities if Interchange Transaction requests are approved or denied.

Real Time

~~6.~~7. Notifies ~~Interchange Authorities~~Interchange Coordinators of Transaction Cancellations or Terminations.

Function

Function – Load-Serving

Definition

Secures energy and transmission service (and related Interconnected Operations Services) to serve the end-use customer.

Tasks

1. Collect, acqrire or develop individual and ~~develop~~ overall load profiles and forecasts of end-user energy requirements. (Daily, weekly, monthly, annually etc…)

2. Identify and provide facilities for load curtailment

3. Identify and provide facilities for self-provided Interconnected Operations Services

4. Negotiate agreements for needed energy, transmission service, and Interconnected Operations Services

5. Manage resource portfolios to meet demand and energy requirements of end-use customers.

Entity

Responsible Entity – Load-Serving Entity

Relationships with other Responsible Entities

Making Deals

1. Assists end-use customers develop and submit load profiles, plans, and forecasts as needed to the Balancing Authorities, Generator Owners, Generator Operators, Purchasing-Selling Entities, ~~Planning Authority~~Interconnection Planning Coordinators, Resource Planners, Transmission Planners, and Market Operator(s).
2. Assists Purchasing-Selling Entities in arranging for the delivery of energy to a specific metering point for loads via bilateral contracts
3. Assists Generator Owners and Generator Operators on behalf of end-use customers in securing energy and Interconnected Operations Services needed via bilateral contracts. (In this role the Load Serving Entity is acting like the Purchasing-Selling Entity.)

Ahead of Time

4. Arranges for transmission service via Transmission Service Providers.
5. Provides generation (affiliated and non-affiliated) commitments and dispatch schedules to the Balancing Authority or Market Operator (where applicable).
6. Works with end-use customers to identify new facility connection needs
7. Works with Resource Planners to ensure planned purchases that cross ~~Planning Authority~~Interconnection Planning Coordinator Area boundaries are properly reported for system modeling and reliability assessments
8. Coordinates with Transmission Planner and the ~~Planning Authority~~Interconnection Planning Coordinator on data requirements for system modeling and transmission expansion.
9. Works with the Balancing Authorities and ~~Transmission Operator~~Transmission ~~s~~Authorities for implementing load shedding during emergency conditions and to provide load interruption capability as an Interconnected Operations Service.

Real Time

10. Assists Distribution Providers in implementing load shedding during emergency conditions and Balancing Authorities to provide load interruption capability as an Interconnected Operations Service

Function – Compliance Monitoring

Definition

Monitors, reviews, and ensures compliance with Reliability Standards and administers sanctions or penalties for non-compliance to the standards.

Tasks

1. Audit and document NERC Reliability Standard compliance of all registered Responsible Entities ~~to Reliability Standards~~
2. Recommend ~~sanctions or penalties~~actions to resolve ~~for~~ non-compliance with Reliability Standards

Entity

Responsible Entity – Compliance Monitor

Relationships with other Responsible Entities

1. Receives oversight direction from the Standards Developer for consistency
2. Monitors all responsible entities as required by Reliability Standards and Certification Criteria.
3. Provides compliance information to the Standards Developer and others as appropriate

Function

Function – Standards Development

Definition

Develops, maintains, and implements Reliability Standards to ensure the reliability of the interconnected bulk electric transmission systems in the United States, Canada, and Baja California Norte, Mexico. Add reference footnote to the NERC Standard Development Process

Tasks

1. Develop Reliability Standards for the planning and operation of the interconnected bulk electric transmission systems that serve the United States, Canada, and Baja California Norte, Mexico.
2. Develop compliance measurement and enforcement procedures for each Reliability Standard.
3. Develop Criteria and Certification Procedures for Balancing, Interchange, and ~~Reliability Authorities~~Interconnection Reliability Authorities, ~~Transmission Operator~~Transmission ~~s~~Authorities, and others as needed.
4. Provide for appeals and dispute resolution procedures.

Responsible Entity – Standards Developer

Relationships with other Responsible Entities

Coordinates with other standards-approving organizations

Coordinates via due process with the public (mainly industry participants) as defined in the Standards Development Process Manual.

Provides oversight direction to the Compliance Monitor for consistency.

Functional Model Approval Procedure

Changes to the Functional Model are approved by the standing committees and the board of trustees. The Functional Model is the guiding framework for the Reliability Standards, and the functions, their definitions, and interrelationships ~~must~~ should be observed as Standard Authorization Requests (SA ~~SA~~Rs) and Standards are drafted. Doing otherwise would cause conflicts among the Reliability Standards as they are developed over time.

The Functional Model Working Group considers all requests to revise the Functional Model, and manages the revision process:

1. Functional Model Working Group reviews the proposed revision to the Model, considering current Reliability Standards, and SARs and Standards being drafted. The Working Group shall respond within 90 days and shall ~~will~~ work with the individual or group requesting the change to the Model.

2. Working Group posts revision for public comment for 45 days.

3. Working Group submits revision to the standing committees for review and approval. (The revision will include an implementation date for the revisions.)

4. Working Group submits standing committee-approved revision to the NERC Board of Trustees for approval.

5. NERC staff posts revised Functional Model.

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

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

Interchange Authority Implementation Task Force

Report to the Interchange Subcommittee

Introduction

In considering the implementation of the NERC Reliability Functional Model, the Operating Committee charged the Interchange Subcommittee (IS) with operationally defining the Interchange Authority (IA) function. The Interchange Authority Function Task Force (IAFTF) was formed to compile and address the outstanding issues surrounding the IA function, and define how the IA function would operate with the adoption of standards related to the NERC Reliability Functional Model (FM). The IAFTF developed a white paper to define how the tasks of an Interchange Authority could be performed operationally and how the Interchange Authority function interrelates with other functions – both market and reliability.

When the white paper was presented to the NERC Operating Committee (OC), they requested the Interchange Subcommittee to distribute the report as a means to solicit further comments on the IA functionality from NAESB, the ISO/RTO Council, NERC Functional Model Working Group, and other industry groups and to further develop detailed IA functionality and recommendations for supporting tools.

The IS recognized that the white paper focused on implementation of the IA as defined in the NERC Reliability Functional Model however did not consider the initial implementation of the Version 0 Standards or the transition to Version 1 Standards. To address this issue and the charge from the NERC OC, the IS formed the Interchange Authority Implementation Task Force (IAITF) to provide recommendations on the implementation of the Interchange Authority.

Executive Summary

The purpose of this report is to provide recommendations on how to implement the concept of an Interchange Authority (IA) into an industry that "operates" within the Functional Model. In providing recommendations for the implementation of the IA, the task force focused on key milestones to which the recommendations are aligned. The recommendations are based on the following implementation timeframes:

a) Near Term – Recommendations that can be put in place to support the implementation of the Version 0 Standards that will take place on April 1, 2005. (All required changes may not be completed by this date)
b) Mid Term – Recommendations that can be implemented in support of the Version 1 Coordinate Interchange Standard.
c) Long Term – Recommendations in support of the conclusions of the Interchange Authority Function Task Force white paper to implement a single interconnection-wide IA.

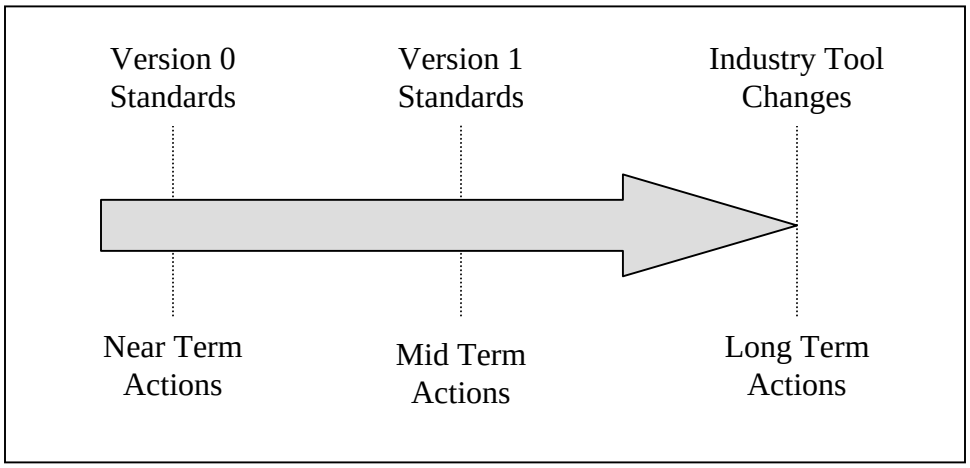


Figure 1 – Recommendation Timeframes

The report provides options associated with each of the implementation milestones and identifies considerations associated with each option. These options were only considered if they could be applied in the time required to effectively meet the implementation milestones. The task force recommendations include the specific action items required to implement them and the responsible party.

Near Term Implementation Options

The near term options considered by the task force were limited to those solutions that could be put in place to support the implementation of the Version 0 Standards that will take place on April 1, 2005 or within a reasonable period of time thereafter. The task force analyzed the results of the mapping of IA tasks to Version 0 requirements and used it as a means of formulating the recommendations. In the following options, consideration was given to functional specifications for tool changes, clarification of the Version 0 Standards and revisions to reference guides.

Option 1

The Sink Balancing Authority (BA) will perform the interchange tasks of the current Sink Control Area and those associated with the Tag Authority in E-tag. The mapping in Appendix C & D show where the IA requirements are being met in the Version 0 Standards. Considerations:

a) Revise the definition of the IA to remove the term "authority" and replace it with the term "coordinate". Modify the definition of Interchange Authority in the Functional Model as follows:
~~Authorizes~~ *Coordinates and communicates* implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures Interchange *is* ~~Transactions are~~ properly identified for reliability assessment purposes.
In addition, the tasks of the IA should be modified to more closely reflect this definition as outlined in Appendix A. The relationship of the IA with other functional entities should be modified as shown in Appendix B.

b) Rename the Interchange Authority to Interchange Coordinator. The formal change in name from IA to IC may remove some concern related to the use of the word "authority" and may more closely reflect actual practice and expectations.

c) Modify the Functional Model (as identified in Appendix A & B) to include the revised IA tasks under the Balancing Authority. (Note: This may not require a wholesale change to the Functional Model. Mapping of tasks to the BA can be done with an explanatory note without removing the IA from the Functional Model.)

d) Issue a letter to the industry explaining the role of the BA under the Version 0 Standards and relationship to the functional model as per the above.

e) Modify the existing Interchange Guideline as a reference document associated with the Version 0 interchange standards to clarify the role of adjacent TSP's in ensuring a contiguous transmission path by including adjacent TSP's on E-tags.

Option 2

Do nothing. The interchange and tagging tasks performed by the Control Areas today are performed by the Balancing Authority under the Version 0 Standards. The IA is not a registered entity and is not referred to in the Version 0 Standards. Considerations:

a) The BA as described in the functional model will not correctly refer to the interchange and tagging tasks being performed under Version 0.
b) The Electronic Tagging Functional Specification still refers to the role of the Control Area as the Tag Authority.

Mid Term Implementation Options

The mid term options considered by the task force were limited to those solutions that could be put in place in conjunction with the issuance of the Version 1 Coordinate Interchange Standard. This Standard is currently under development based on the existing NERC functional model will require further revision to coordinate with any changes to the functional model.

Option 1

Require that the organization performing the Tag Authority function register as the IA (see figure 2). The Electronic Tagging Functional Specification assigns the Tag Authority requirements to the "entity responsible for Control Area operations". This has been translated to the Sink BA in the current Version 0 Standards. Considerations:

a) Revise the Electronic Tagging Functional Specification to reflect functional model language and map the Tagging Service requirements from the Control Area to the Interchange Coordinator (IC) performing the Interchange function for a Sink Balancing Authority's organization. (Note: This does not preclude the Balancing Authority from using a third party to fulfill these requirements.) **Action:** NERC IS to assign this action to TISWG. TISWG to consider the following:
    1. Updating the TSIN registry to include Functional Model entities.
    2. Impact analysis of the E-tag modifications required to implement the Functional Model entities.
b) Require registration to the revised IC entity.
c) Revise the version 1 Coordinate Interchange Standard to reflect the modified IA (IC) tasks and relationships as identified in Appendix A and B.

Option 2

Revise the Coordinate Interchange Standard to reflect current day interchange and tagging requirements. Considerations:

a) Depending on the decision made regarding mid and long term recommendations, either remove the IA from the Functional Model or leave it as a place holder. If left as a place holder until long term recommendations are implemented, it must be made clear in the Functional Model that the IA entity will not be implemented under the Version 1 Standards.
b) Remove the "how" language from the existing version 0 standard and focus on the "what" without using the IA terminology.

Long Term Implementation Options

In considering the long term options for implementing the Interchange Authority, the task force focused on the option proposed by the Interchange Authority Function Task Force white paper. Comments received on the IAFTF white paper indicate industry support for Option 3 (consolidated approach). This option would create a single NERC wide or interconnection wide IA. Upon completion of the commercial functions as prescribed by NAESB during the Market Period, the submitting PSE would send the completed balanced request for interchange to a defined IA. This IA would be responsible for:

1. Distributing the Request for Interchange (RFI) to all affected reliability entities.
2. Obtaining confirmation of the RFI from the reliability entities.
3. Distributing status of the confirmation process.
4. Authorizing implementation of physical interchange by the affected BAs.
5. Forwarding individual confirmed RFI(s) along with appropriate net interchange information to the appropriate reliability assessment systems e.g. Interchange Distribution Calculator (IDC).
6. Maintaining records of scheduled interchange.

Option 1

The Task Force reviewed the issues associated with the implementation a single industry wide IA and considered the following:

a) Perform a cost benefit analysis of the tool changes required to implement the IA. Consideration should be given to both a new industry wide tool in addition to modifications to the existing E-tag functionality.
b) Consider the proposed industry move to OASIS Phase II. Electronic scheduling associated with this tool may allow IA type functionality to be implemented.

Recommendations

Near Term

Review "Near Term" recommendations a, b, and c.

The sink Balancing Authority (BA) will perform the interchange tasks of the current sink Control Area and those associated with the Tag Authority in E-tag (see figure 2). The mapping in Appendix C & D shows where the IA requirements are being met in the Version 0 Standards. The following actions are required to accomplish this:

a) Revise the definition of the IA to remove the term "authority" and replace it with the term "coordinate". Modify the definition of Interchange Authority in the Functional Model as follows:
~~Authorizes~~ *Coordinates and communicates* implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures Interchange *is* ~~Transactions are~~ properly identified for reliability assessment purposes.
In addition, the tasks of the IA should be modified to more closely reflect this definition as outlined in Appendix A. The relationship of the IA with other functional entities should be modified as shown in Appendix B.
Action: NERC IS to send a letter to the Functional Model Working Group requesting the changes to the NERC Functional Model as outlined in Appendices A & B.

b) Rename the Interchange Authority to Interchange Coordinator. The formal change in name from IA to IC may remove some concern with the use of the word "authority" and may more closely reflect actual practice and expectations.
Action: NERC IS to draft a letter to the Functional Model Working Group to request a change to the Functional Model.

c) Modify the Functional Model (as identified in Appendix A & B) to include the revised IA tasks under the Balancing Authority. (Note: This may not require a wholesale change to the Functional Model. Mapping of tasks to the BA can be done with an explanatory note without removing the IA from the Functional Model.)
Action: NERC IS to send a letter to the Functional Model Working Group requesting that, for Version 0, the revised IA tasks as described in the above be mapped to the BA in the functional model.

d) Modify the existing Interchange Guideline as a reference document associated with the Version 0 interchange standards to clarify the role of adjacent TSP's in ensuring a contiguous transmission path by including adjacent TSP's on E-tags. **Action:** NERC IS to assign this action to the Interchange Guideline Working Group.

Mid Term

Require that the organization performing the Tag Authority functions register as the modified IA (IC) (see figure 2). The Electronic Tagging Functional Specification assigns the Tag Authority requirements to the "entity responsible for Control Area operations". This has been translated to the Sink BA in the current Version 0 Standards. The following actions are required to accomplish this:

a) Revise the Electronic Tagging Functional Specification to reflect functional model language and map the Tagging Service requirements from the Control Area to the Interchange Coordinator (IC) performing the Interchange function for a Sink Balancing Authority's organization.. (Note: This does not preclude the Balancing Authority from using a third party to fulfill these requirements.)
   Action: NERC IS to assign this action to TISWG. TISWG to consider the following:
   1) Updating the TSIN registry to include Functional Model entities.
   2) Impact analysis of the E-tag modifications required to implement the Functional Model entities.
b) Require registration to the modified IA (IC) entity.
   Action: NERC IS to draft a letter to the NERC body responsible for registration, requesting that registration for the revised IA be completed in conjunction with the implementation of the Version 1 Coordinate Interchange Standard.
c) Revise the version 1 Coordinate Interchange Standard to reflect the modified IA (IC) tasks and relationships as identified in Appendix A and B.
   Action: Coordinate Interchange Standards drafting team.

Long Term

The Task Force reviewed the issues associated with the implementation a single industry wide IA and recommend that NERC consider the following:

a) Perform a cost benefit analysis of the tool changes required to implement the IA. Consideration should be given to both a new industry wide tool and modifications to the existing E-tag functionality.
b) Consider the proposed industry move to OASIS Phase II. Electronic scheduling associated with this tool may allow IA type functionality to be implemented.

Appendix A – Recommended Interchange Authority Functional Tasks Modifications

1. ~~Determine~~ *Consolidate evaluations of* valid, balanced, Interchange Schedules (validation of sources and sinks, transmission arrangements, interconnected operations services, etc.).

2. ~~Verify~~ *Collect* ramping capability *confirmations* of ~~the source and sink~~ Balancing Authority Areas for requested Interchange Schedules

3. *Coordinate (i.e.,* Collect, *consolidate*, and disseminate*)* Interchange ~~Transaction~~ approvals, changes, and denials

~~4. Authorize implementation of Interchange Transactions~~

5. ~~Enter~~ *Communicate* Interchange Transaction information ~~in~~to Reliability Assessment Systems (e.g., the Interchange Distribution Calculator in the Eastern Interconnection)

6. Maintain a record of individual Interchange *Schedules* ~~Transactions~~

Notes: These tasks can be mapped to the current practices of the industry as follows:

- Task 1 – The evaluation is done in a distributed manner today by various BA's and TSP's and the Tag Authority service of the E-tag performs consolidation see figure 2 (note the distributed evaluation is not a change from the Functional Model)
- Task 2 – The collection of ramping confirmations is done by Tag Authority service of E-tag see figure 2 (note: the distributed ramping confirmation is not a change from the Functional Model)
- Task 3 – The coordination is performed by the Tag Authority service of E-tag see figure 2 (this is not a change from the Functional Model)
- Task 4 – Since there is no designated single, unified authorization today, this task should be eliminated
- Task 5 – This communication is performed by the Tag Authority service to the IDC in the Eastern Interconnection. See figure 2 (this is not a change from the Functional Model)
- Task 6 – The record retention is performed in a distributed manner by the various Tag Authority Services. (This function is satisfied by the archiving feature of E-tag in the Eastern Interconnection[1] and as an archiving requirement in the Western Interconnection[2].) This is not a change from the Functional Model

[1] E-tag Functional Specification – Version 1.7.05: Historical Tag Archive
Every service shall keep available for retrieval every Tag and associated messages received by the service until that Tag's stop date/time is more than ninety (90) days in the past. Authorities must have this information available to Approval and Agent systems through standard E-Tag querying mechanisms throughout the ninety-day period, as well as through written request by other parties who may require data but not be participants listed on the Tag (i.e., NERC). Tag Agent and Approvals must have these Tags available by written request.

[2] The WECC's electronic tag retention requirement is 1 year unless the tag(s) are the subject of an ongoing dispute and then they must be retained until the dispute is resolved.

Appendix B - Recommended Interchange Authority Entity Relationship Modifications

Ahead of Time

1. ~~Verifies ramping capability for requested Interchange Schedules with Balancing Authorities.~~ *Redundant to item 5. Accomplished by "Ahead of Time" relationship 5*

2. Receives requests from Purchasing-Selling Entities to implement Interchange Transactions. (Done by the PSE tag agent service communicating with the tag authority service of the sink BA see figure 2)

3. Submits all Interchange Transaction requests to the Reliability Authorities, Balancing Authorities, and Transmission Service Providers for approvals.(Done by the BA tag authority service submitting tags to the tag approval service of entities involved in the transaction see figure 2)

4. Receives confirmation from Transmission Service Providers of transmission arrangement(s). *(Note: Clarification is required regarding the role of the sink PSE in ensuring a contiguous transmission path by including appropriate TSP's on E-tags.)* (Done by the TSP tag approval service communicating with the BA tag authority service see figure 2)

5. Receives confirmation from Balancing Authorities of the ability to meet ramping requirements for submitted Interchange Schedules. (Done by the TSP tag approval service communicating with the BA tag authority service see figure 2)

6. ~~Receives information from Balancing Authorities of expected Interconnected Operations Services deployments that result in an Interchange Transaction (for example, an Interchange Schedule that is enabled by reducing load in a Balancing Authority Area, which frees up resources.)~~ *Comment: Move this function to the BA.*

7. ~~Informs Purchasing-Selling Entities on implementation of load-provided Interconnected Operations Services that were bid into the market that result in an Interchange Transaction.~~ *Comment: Move this function to the BA.*

8. ~~Provides approved, valid, and balanced Interchange Schedules to the Balancing Authorities for implementation.~~ *Balancing Authorities ensure valid and balanced Interchange Schedules by BA to BA confirmation (see figure 4).*
Comment: Move this function to the BA.

Real Time

9. Provides Transmission Service Providers with the requested Interchange Transactions received from Purchasing Selling Entities using that Transmission Service Providers' transmission system. .(Done by the BA tag authority service submitting tags to the tag approval service of entities involved in the interchange transaction (see figure 2)

10. Receives curtailments and redispatch implementation from Reliability Authorities. (Done by the Reliability Authority communicating with the Sink BA tag authority service see figure 3)

11. Informs Transmission Service Providers, Purchasing-Selling Entities, Reliability Authorities, and Balancing Authorities of Interchange Schedule Implementations and Curtailments. (Done by the Sink BA tag authority service communicating with the agent and approval service see figure 3)

12. Receives information on Interchange Schedule interruptions due to generation loss or load interruption from the Balancing Authorities.(Done by communication with the sink BA receiving a reliability modification request and communicating it with the appropriate entities see figure 3)

After the hour

Maintains and provides records of individual Interchange Transactions for the Balancing Authorities.

Appendix C – Mapping of IA Functions

Function #	Description	Version 0 Requirement	Responsible Entity
IA 1	Determine valid, balanced, Interchange Schedules (validation of sources and sinks, transmission arrangements, interconnected operations services, etc.).	Done in a distributed fashion using E-tag.	TSP, Sink BA, TOP
IA 2	Verify ramping capability of the source and sink Balancing Authority Areas for requested Interchange Schedules	INT-002-0 R3.3 INT-003-0 R1.3 INT-003-0 R1.1.3	BA
IA 3	Collect and disseminate Interchange Transaction approvals, changes, and denials	INT-003-0 R1	Sink BA
IA 4	Authorize implementation of Interchange Transactions	INT-002-0 R2 INT-002 -0 R3 INT-002-0 R5 INT-003-0 R4	TSP;BA
IA 5	Enter Interchange Transaction information into Reliability Assessment Systems (e.g., the Interchange Distribution Calculator in the Eastern Interconnection)	INT-002-0 R 1.4. The Sink Balancing Authority shall ensure that all tags and any modifications to tags are provided via a secure network to the following entities on the Scheduling Path: Security Analysis Services (IDC or other regional reliability tools).	Sink BA
IA 6	Maintain record of individual Interchange Transactions	Maintained in E-tag for 90 days	Tag Authority Service

Appendix D - Interchange Coordinator (IC) Mapping to Version 0

INT-001-0	R 3.	The Balancing Authority or Purchasing Selling Entity responsible for submitting the tag shall submit all tags to the Sink Balancing Authority (IC) according to timing tables in Attachment 1-INT-001-0.
INT-002-0	R 1.	The Sink Balancing Authority (IC) shall ensure that all tags and any modifications to tags are provided via a secure network to the following entities on the Scheduling Path:
INT-002-0	R 4.	Each Balancing Authority and Transmission Service Provider on the Scheduling Path shall communicate their approval or denial of the Interchange Transaction to the Sink Balancing Authority (IC).
INT-002-0	R 5.	Upon receipt of approvals or denials from all of the individual Balancing Authorities and Transmission Service Providers, the Sink Balancing Authority (IC) shall communicate the composite approval status of the Interchange Transaction to the Purchasing-Selling Entity and all other Balancing Authorities and Transmission Service Providers on the Scheduling Path and through the Reliability analysis service to affected Transmission Operators and Reliability Coordinators.
INT-003-0	R 4.	The Sink Balancing Authority shall be responsible for initiating implementation of each Interchange Transaction as tagged. Upon receiving composite approval from the Sink Balancing Authority (IC), each Balancing Authority on the scheduling path shall enter confirmed schedules into its ACE equation
INT-004-0	R 1.	If a Reliability Coordinator, Transmission Operator, or Source or Sink Balancing Authority, due to a reliability event, needs to modify an Interchange Transaction that is in progress or scheduled to be started, the entity shall, within 60 minutes of the start of the emergency Transaction, modify the Interchange Transaction tag, and shall communicate the modification to the Sink Balancing Authority (IC).
INT-004-0	R 3.	Upon receipt of modification to an Interchange Transaction as described in Requirement R1, the Sink Balancing Authority (IC) (Source Balancing Authority in the case of a loss of generation) shall communicate the modified information about the Interchange Transaction, including its composite approval status, to all Balancing Authorities and Transmission Service Providers on the Transaction path and the Purchasing-Selling Entity responsible for the Transaction.
INT-004-0	R 4.	At such time as the reliability event allows for the reloading of the transaction, the entity that initiated the curtailment shall release the limit on the Interchange Transaction tag to allow reloading the transaction and shall communicate the release of the limit to the Sink Balancing Authority (IC).

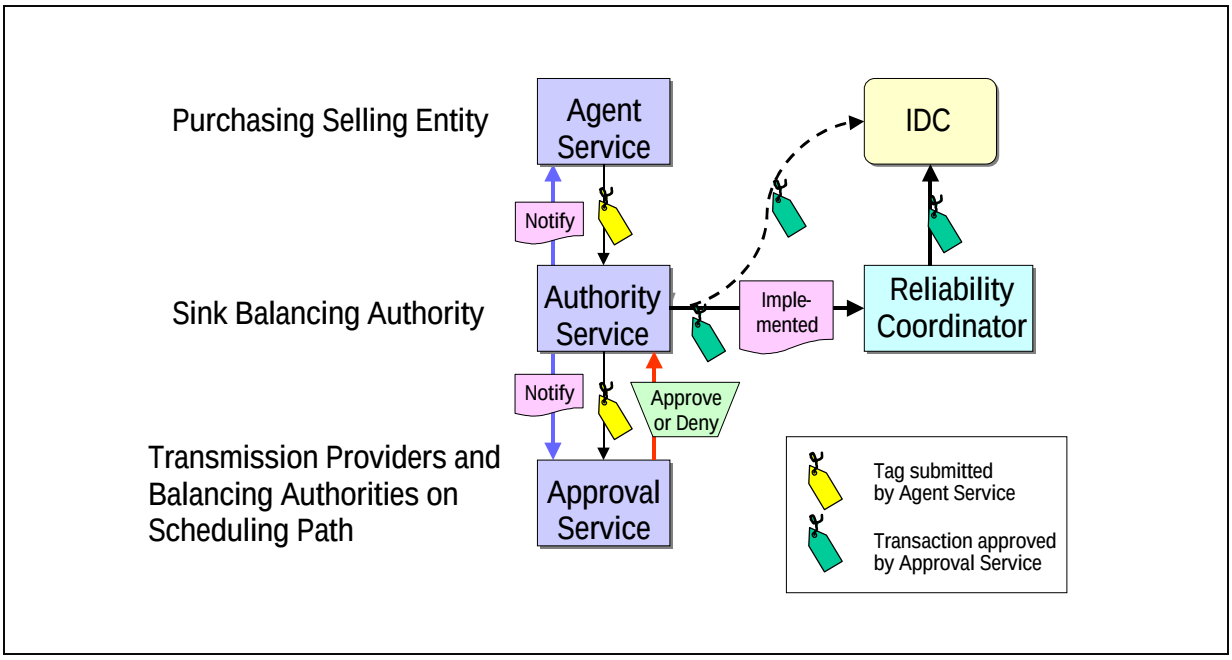


Figure 2 – Tagging Services

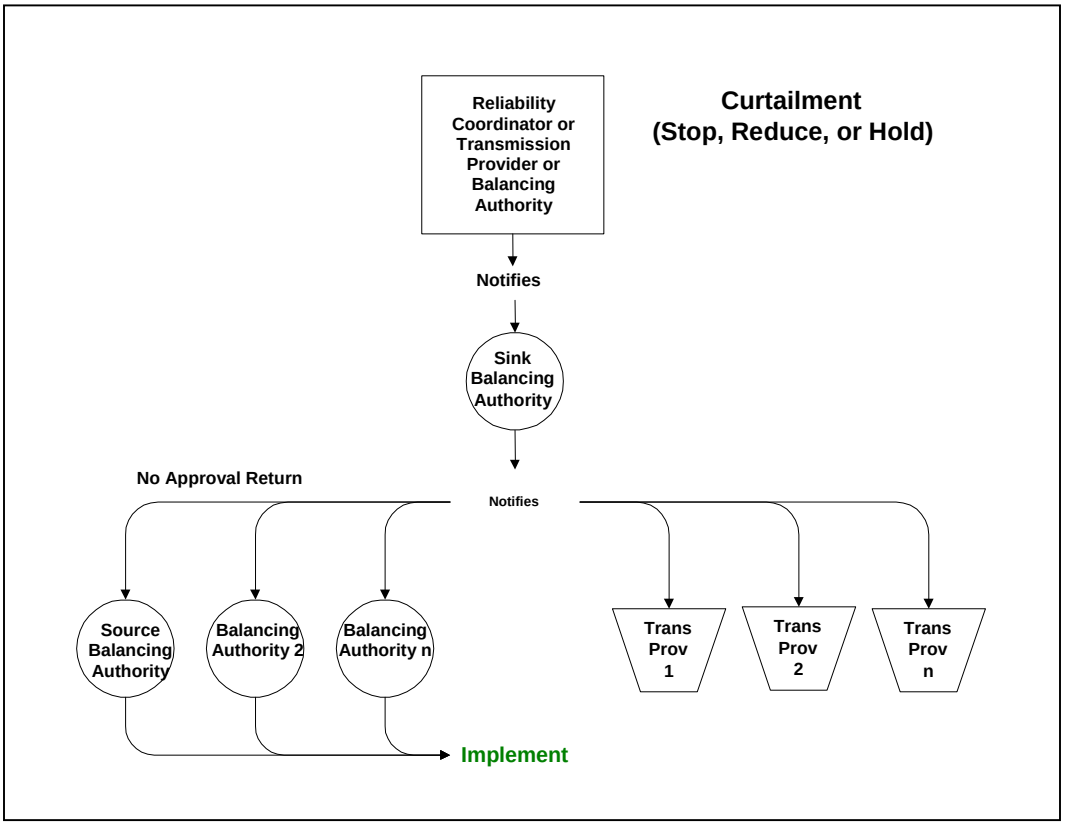


Figure 3 - Tag Curtailment

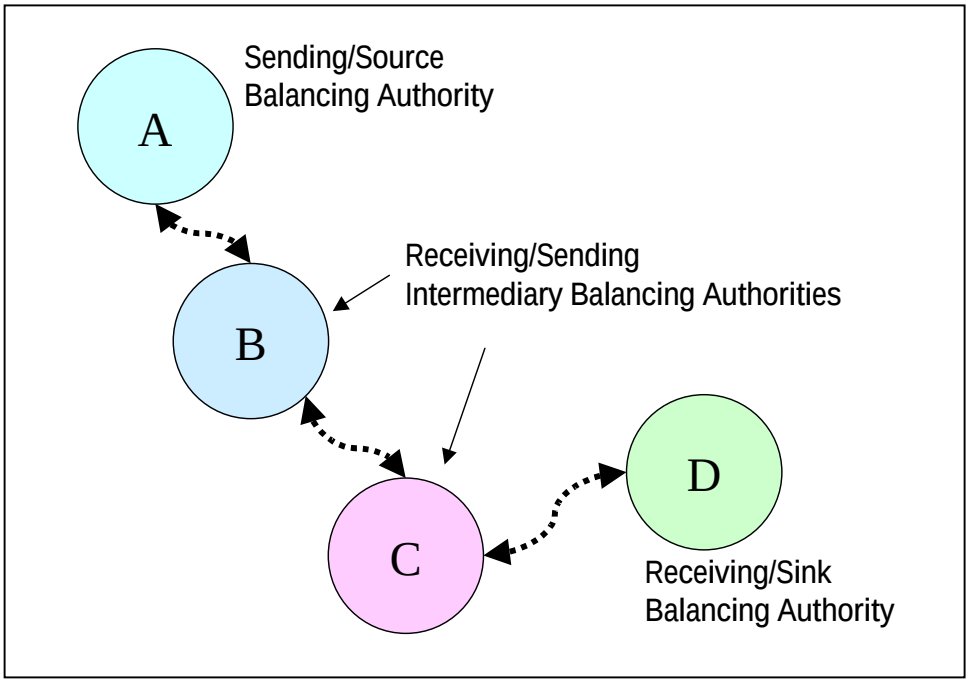


Figure 4 - BA to BA Schedule Confirmation

NERC Reliability Functional Model

Function Definitions and Responsible Entities

Version 2

Approved by Standing Committees: November 11 – 13, 2003
Approved by Board of Trustees: February 10, 2004

Prepared by the
Functional Model Review Task Group
Planning Reliability Model Task Force

Contents

Foreword

This document replaces Version 1 of the NERC Functional Model that the Board of Trustees approved in June 2001.

* * *

Historically, Control Areas were established by vertically integrated utilities to operate their individual power systems in a secure and reliable manner and provide for their customers' electricity needs. The traditional Control Area operator balances its load with its generation, implements interchange schedules with other Control Areas, and ensures transmission reliability.

As utilities began to provide transmission service to other entities, the Control Area also began to perform the function of Transmission Service Provider through tariffs or other arrangements. NERC's Operating Policies and Standards have reflected this traditional electric utility industry structure, and ascribed virtually every reliability function to the Control Area.

Beginning in the early 1990s with the advent of open transmission access and restructuring of the electric utility industry to facilitate the operation of wholesale power markets, the functions performed by Control Areas began to change to reflect the newly emerging industry structure. These changes occurred because:

1. Some utilities were separating their transmission from their Merchant Functions (functional unbundling), and even selling off their generation,

2. Some states and provinces were instituting "customer choice" options for selecting energy providers, and

3. The developing power markets were requiring wide-area transmission reliability assessment and dispatch solutions, which were beyond the capability of many Control Areas to perform.

As a result, the current NERC Operating Policies, which are centered on Control Area operations, were beginning to lose their focus, and become more difficult to apply and enforce.

The Control Area Criteria Task Force. The NERC Operating Committee formed the Control Area Criteria Task Force in 1999 to address this problem. The Task Force began by listing all the tasks required for maintaining electric system reliability and then organizing these tasks into basic groups that it called "functions." The Task Force then attempted to assign these functions to the basic "reliability organizations" such as Control Areas or Regional Transmission Organizations. But that didn't work because the Control Areas themselves were unbundling some of the functions they traditionally performed, and the emerging RTOs and ISOs, while following structures as defined in Order 2000, were not alike.

Realizing that there was no longer a "standard" reliability organization, the Task Force decided to build a "Functional Model" consisting of the functions that ensure reliability and meet the needs of the marketplace. Then, organizations—whether they be traditional, vertically-integrated control areas, regional transmission organizations, independent

system operators, independent transmission companies or so on—can "roll up" those functions they perform, and register with NERC as one or more of the following: Generator Owners, Generator Operators, Transmission Service Providers, Transmission Owners, Transmission Operators, Distribution Providers, Load Serving Entities, Purchasing-Selling Entities, Reliability Authorities, Planning Authorities, Balancing Authorities, Interchange Authorities, Transmission Planners, Resource Planners, Standards Developers, and the Compliance Monitors. This enables NERC to rewrite its reliability standards in terms of these entities who perform the reliability functions.

Excerpted and revised from Version 1 of the NERC Functional Model
June 12, 2001

Introduction

The NERC Functional Model defines the set of functions that must be performed to ensure the reliability of the bulk electric system. It also explains the relationship between and among the entities responsible for performing the tasks within each function. The Model provides the foundation and framework upon which NERC develops and maintains its Reliability Standards. NERC's Reliability Standards establish the requirements of the responsible entities that perform the functions defined in this Model.

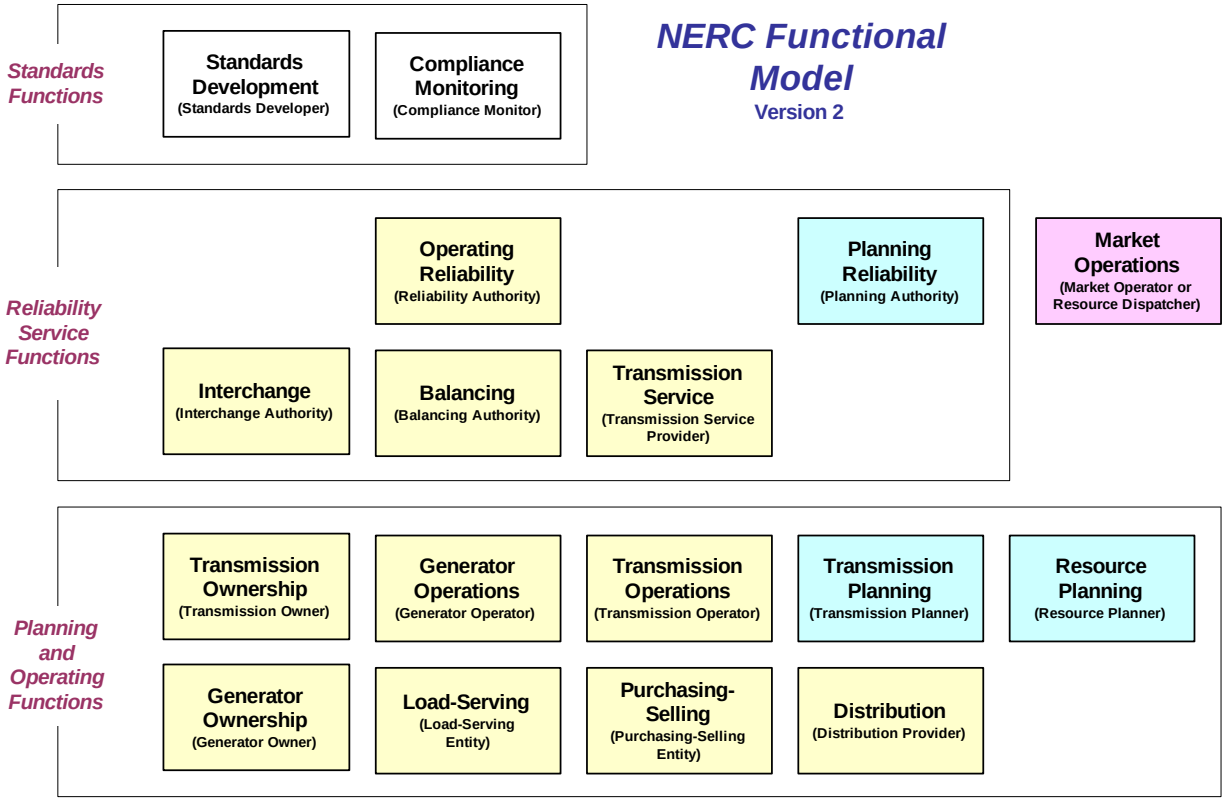
While the Model is not a standard, and does not have compliance requirements, the Reliability Standards must respect the definitions and interrelationships contained in the Model. Doing otherwise could result in Reliability Standards that conflict with one another.

The Model does not prescribe any particular organization or market structure. Organizations may perform one or more functions as they see fit, but must recognize that some functions require the organization and its personnel to be certified to perform that function. Organizations must also recognize that, as responsible entities, they are responsible for ensuring that all tasks within each function are performed. While organizations may agree to split the tasks of a particular function (for example, an RTO may perform some Transmission Operator tasks with their members performing the remainder), NERC will require that one of the organizations be the "responsible entity," ensuring that all of the tasks of the function are performed.

Functional Model maintenance. The Functional Model is maintained by the NERC standing committees and Board of Trustees. The section titled, "Functional Model Approval Procedure," in this document explains the procedures for reviewing and revising the Model.

Technical discussions. The companion document, "Functional Model – Technical Discussions," provides additional details on the functions themselves, how organizations can "roll up" those functions they wish to perform, and how organizations as "responsible entities" interrelate.

Functional Model Diagram



Function Name	*Responsible Entity*
Operating Reliability Function	Reliability Authority
Planning Reliability Function	Planning Authority
Balancing Function	Balancing Authority
Interchange Function	Interchange Authority
Transmission Service Function	Transmission Service Provider
Transmission Ownership Function	Transmission Owner
Transmission Operations Function	Transmission Operator
Transmission Planning Function	Transmission Planner
Resource Planning Function	Resource Planner
Distribution Function	Distribution Provider
Generator Ownership Function	Generator Owner
Generator Operations Function	Generator Operator
Load-serving Function	Load-serving Entity
Purchasing-Selling Function	Purchasing-Selling Entity
Market Operations Function	Market Operator (or Resource Dispatcher)
Standards Development Function	Standards Developer
Compliance Monitoring Function	Compliance Monitor

Terms used in the Functional Model

Areas

Reliability Authority Area. The collection of generation, transmission, and loads within the boundaries of the Reliability Authority. Its boundary coincides with one or more Balancing Authority Areas.

Balancing Authority Area. The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.

Transmission Planning Area. That area under the purview of the Transmission Planner.

Planning Authority Area. That area under the purview of the Planning Authority. It will include one or more Transmission Planning Areas.

General

Task. One of the elements that make up a Function in the Functional Model.

Responsible Entity. The label that NERC applies to an organization that is responsible for carrying out the tasks within a Function.

Function. A group of tasks that can not be logically subdivided into other groups.

Authority. The highest level of responsible entity for a particular function. The Reliability Authority is the highest level of all responsible entities.

Transaction. An agreement arranged by a Purchasing-Selling Entity to transfer energy from a seller to a buyer.

Transmission Arrangements. An agreement between a Transmission Service Provider and Transmission Customer (Purchasing-Selling Entity, Generator Owner, Load-Serving Entity) for transmission services.

Customer. A Purchasing-Selling Entity, Generator Owner, Load-Serving Entity, or End-user.

End-use Customer. The customer served by a Load-Serving Entity.

Purpose of the Functional Model

The purpose of the NERC Reliability Functional Model is to:

1. Functionalize the tasks being performed today for electric system reliability so that reliability organizations such as Control Areas, Regional Transmission Organizations, Independent System Operators and others can more easily and clearly identify the reliability functions they provide. A specific organization may provide one or more of the functions identified in the Functional Model.

2. Define in general terms each function and the relationships between the entities who are responsible for performing the tasks within the functions. The framework for developing the function definitions is:

    a. The responsibility for performing a function should not be split by organizations

    b. The functions are independent of the organization structure performing the function, and

    c. The function definitions provide flexibility to accommodate the range of presently conceivable organization structures.

3. Provide a framework for Reliability Standards (including organization certification criteria) and compliance measures developed through the NERC Standards Development Process that will apply to certain tasks defined in the Functional Model.

    a. It is not expected that standards will be developed for each task since the Functional Model is developed in more detail than is needed for reliability standards. However, standards may contain more detail than the associated activity in the Functional Model.

    b. Responsibility for compliance with a standard will apply to the organizations performing that function.

    c. Other organizations developing standards may use the NERC Functional Model in the same manner.

4. Provide linkages between business practices developed by other organizations showing how certain practices may relate to the reliability functions in the Functional Model.

Guiding Principles of the Functional Model

For further details, refer to "Functions, Tasks, Responsible Entities, and Organizations" in the Technical Discussions document.

As explained in the "Purpose of the Functional Model," the Functional Model provides the framework on which the NERC reliability standards are based. To ensure that this framework remains viable, the Model itself is governed by a set of "guiding principles" that define a *function*, and establish the relationship between the *responsible entities* who are responsible for performing the *tasks* listed in the Model, and the NERC *reliability standards*. NERC must work within these guiding principles when revising or interpreting the Functional Model to maintain the integrity of the Model and NERC's Reliability Standards.

1. The Functional Model defines the *functions* that must be performed and does not imply organization structure or hierarchy.

    a. Functions comprise *tasks*.

    b. Tasks are *what* must be done, not *how*.

2. An *organization* who registers with NERC as performing a function is considered a *responsible entity* and must ensure that all tasks are performed.

    a. Reliability standards are those requirements that must be performed by *responsible entities*. Thus, we say that the Functional Model is the framework on which the reliability standards are based.

    b. An organization may delegate a task to another organization, but may not delegate its responsibility for ensuring that the task is accomplished.

3. Organizations that perform certain functions must be certified as being capable of performing those functions. Organization certification requirements are a category of NERC standards

4. Some tasks in the Functional Model may not result in a reliability standard.

Function

Function – Operating Reliability

Definition

Ensures the real-time operating reliability of the interconnected bulk electric transmission systems within a Reliability Authority Area.

Tasks

1. Enforce operational reliability requirements
2. Monitor all reliability-related parameters within the Reliability Authority Area, including generation dispatch and transmission maintenance plans
3. Direct revisions to transmission maintenance plans as required and as permitted by agreements
4. Request revisions to generation maintenance plans as required and as permitted by agreements
5. Develop Interconnection Reliability Operating Limits (to protect from instability and cascading outages).
6. Perform reliability analysis (actual and contingency) for the Reliability Authority Area
7. Approve or deny bilateral schedules from the reliability perspective
8. Assist in determining Interconnected Operations Services requirements for balancing generation and load, and transmission reliability (e.g., reactive requirements, location of operating reserves).
9. Identify, communicate, and direct actions to relieve reliability threats and limit violations in the Reliability Authority Area
10. Direct implementation of emergency procedures
11. Direct and coordinate System Restoration

Responsible Entity – Reliability Authority

Relationships with other Responsible Entities

Ahead of Time

1. Receives facility and operational data from Generator Operators, Load-Serving Entities, Transmission Owners, Generator Owners, Transmission Operators, Distribution Providers.
2. Calculates Interconnection Reliability Operating Limits based on Transmission Owners' and Generator Owners' specified equipment ratings.
3. Receives generation dispatch from Balancing Authorities and issues dispatch adjustments to Balancing Authorities to mitigate congestion within the Reliability Authority Area (if not resolved through market mechanisms).
4. Receives Interchange Transactions from Interchange Authorities for reliability analysis.
5. Provides Interchange Transaction approvals to Interchange Authorities based on reliability analysis.
6. Receives generation operation plans and commitments from Balancing Authorities for reliability analysis of Reliability Authority Area.
7. Receives transmission maintenance plans from Transmission Operators for reliability analysis of Reliability Authority Area.
8. Direct Transmission Operators to revise transmission maintenance plans as required and as permitted by agreements.
9. Provides reliability analyses to Transmission Operators, Generator Operators, Transmission Service Providers, and Balancing Authorities in its Area as well as other Reliability Authorities.

Real Time

10. Receives real-time operational information from Balancing Authority and Transmission Operator for monitoring.
11. Issues reliability alerts to Generator Operators, Load-Serving Entities, Transmission Operators, Transmission Service Providers, Balancing Authorities, Interchange Authorities, Planning Authorities, Regional Councils, and NERC.
12. Issues corrective actions (e.g., curtailments or load shedding) to Transmission Operators, Transmission Service Providers, Balancing Authorities, and Interchange Authorities.
13. Coordinates reliability processes and actions with and among other Reliability Authorities.
14. Coordinates with Transmission Planners, Planning Authority, and Transmission Service Providers on transmission system limitations.
15. Coordinates with Planning Authorities on reliability issues, as appropriate.

Special Considerations

The Reliability Authority's purview must be broad enough to enable it to calculate Interconnection Reliability Operating Limits, which may be based on the operating

parameters of other transmission systems beyond the Transmission Operator's vision. The Transmission Operator is responsible for the reliability of its "local" transmission system, and may not be aware that its system is violating an Interconnection Reliability Operating Limit. Therefore, the Reliability Authority may direct the Transmission Operators or Balancing Authorities to take action to mitigate Interconnection Reliability Operating Limits.

Function

Function – Planning Reliability

Definition

Ensures a long-term (generally one year and beyond) plan is available for adequate resources and transmission within a Planning Authority Area. It integrates and assesses the plans from the Transmission Planners and Resource Planners within the Planning Authority Area to ensure those plans meet the reliability standards, and develops and recommends solutions to plans that do not meet those standards.

Tasks

1. Develop and maintain transmission and resource (demand and capacity) system models to evaluate transmission system performance and resource adequacy.
2. Maintain and apply methodologies and tools for the analysis and simulation of the transmission systems in the assessment and development of transmission expansion plans and the analysis and development of resource adequacy plans.
3. Define and collect or develop information required for planning purposes, including:
    a. Transmission facility characteristics and ratings,
    b. Demand and energy end-use customer forecasts, capacity resources, and demand response programs,
    c. Generator unit performance characteristics and capabilities, and
    d. Long-term capacity purchases and sales.
4. Evaluate plans for customer requests for transmission service.
    a. Evaluate responses to long-term (generally one year and beyond) transmission service requests.
    b. Review transmission facility plans required to integrate new (end-use customer, generation, and transmission) facilities into the interconnected bulk electric systems.
5. Review and determine TTC values (generally one year and beyond) as appropriate.
6. Assess, develop, and document resource and transmission expansion plans.
    a. Integrate and verify that the respective plans for the Planning Authority Area meet reliability standards.
    b. Identify and report on potential transmission system and resource adequacy deficiencies, and provide alternate plans that mitigate these deficiencies.
7. Provide analyses and reports as required on the long-term resource and transmission plans for the Planning Authority Area.
8. Monitor transmission expansion plan and resource plan implementation.
9. Coordinate projects requiring transmission outages that can impact reliability and firm transactions.

10. Evaluate the impact of revised transmission and generator in-service dates on resource and transmission adequacy.

Responsible Entity – Planning Authority

Relationships with other Responsible Entities

1. Collects information as appropriate, including:

    a. Transmission facility characteristics and ratings from the Transmission Owners, Transmission Planners, Transmission Operators, and others.

    b. Demand and energy end-use customer forecasts, capacity resources, and demand response programs from Load-Serving Entities and Resource Planners.

    c. Generator unit performance characteristics and capabilities from Generator Owners and others.

    d. Long-term capacity purchases and sales from Transmission Service Providers.

2. Receives requests for long-term transmission service from Transmission Planners and provides the resulting plans to Transmission Service Providers and Transmission Owners.

3. Provides transmission facility plans required to integrate new (end-use customer, generation, and transmission) facilities into the interconnected bulk electric systems to the Transmission Owners, Generator Owners, and other requesters.

4. Coordinates TTC values (generally one year and beyond) with Transmission Planners and neighboring Planning Authorities.

5. Integrates and verifies that the respective plans of the Resource Planners and Transmission Planners meet reliability standards.

6. Coordinates the plans for the interconnection of facilities[1] to the bulk electric systems within its Planning Authority Area with Transmission Planners and Resource Planners.

7. Coordinates as appropriate with resource suppliers outside of the Planning Authority Area.

8. Coordinates transmission system protection and control, including special protection systems, with Transmission Planners, other Planning Authorities, Generator Owners, Generator Operators, Transmission Owners, Transmission Operators, Reliability Authorities, and Distribution Providers.

9. Coordinates with its related Reliability Authority(ies) and other Planning Authorities on reliability issues, as appropriate.

[1] Generators, transmission lines, and end-use customer equipment

Function

Function – Balancing

Definition

Integrates resource plans ahead of time, and maintains load-interchange-generation balance within a Balancing Authority Area and supports Interconnection frequency in real time.

Tasks

1. Must have control of any of the following combinations within a Balancing Authority Area:
    a. Load and Generation (an isolated system)
    b. Load and Scheduled Interchange
    c. Generation and Scheduled Interchange
    d. Generation, Load, and Scheduled Interchange
2. Calculate Area Control Error within the Balancing Authority Area.
3. Review generation commitments, dispatch, and load forecasts.
4. Formulate an operational plan (generation commitment, outages, etc) for reliability assessment
5. Approve Interchange Transactions from ramping ability perspective
6. Implement interchange schedules by entering those schedules into an energy management system
7. Provide frequency response
8. Monitor and report control performance and disturbance recovery
9. Provide balancing and energy accounting (including hourly checkout of Interchange Schedules and Actual Interchange), and administer Inadvertent energy paybacks
10. Determine needs for Interconnected Operations Services
11. Deploy Interconnected Operations Services.
12. Implement emergency procedures

Responsible Entity – Balancing Authority

Relationships with other Responsible Entities

Ahead of Time

1. Compiles load forecasts from Load-Serving Entities.
2. Receives operational plans and commitments from Generator Operators within the Balancing Authority Area
3. Determines amount required and deploys Interconnected Operations Services to ensure balance (e.g., amount of operating reserve, load-following, frequency response) in coordination with the Reliability Authority.
4. Submits integrated operational plans (including maintenance plans from Generator Operators) to the Reliability Authority for reliability assessment and provide balancing information to the Reliability Authority for monitoring.
5. Receives approved, valid, and balanced Interchange Schedules from the Interchange Authorities.
6. Confirms interchange schedules with Interchange Authorities.
7. Confirms ramping capability with Interchange Authorities.
8. Implements generator commitment and dispatch schedules from the Load-Serving Entities and Generator Operators who have arranged for generation within the Balancing Authority Area. The Balancing Authority provides this commitment and dispatch schedule to the Reliability Authority.
9. Provides generation dispatch to its Reliability Authority for reliability analysis.
10. Acquires Interconnected Operations Services from Generator Owners.

Real Time

11. Directs resources (Generator Operators and Load-Serving Entities) to take action to ensure balance in real time.
12. Directs Transmission Operator to reduce voltage or shed load if needed to ensure balance within its Balancing Authority Area.
13. Receives loss allocation from Transmission Service Providers (for repayment with in-kind losses).
14. Provides real-time operational information for Reliability Authority monitoring.
15. Complies with reliability requirements specified by Reliability Authority.
16. Informs Reliability Authority and Interchange Authorities of Interchange Schedule interruptions (e.g., due to generation or load interruptions) within its Balancing Authority Area.
17. Directs Generator Operators to implement redispatch for congestion management as directed by the Reliability Authority.
18. Requests operating information from Generator Operators.
19. Verifies implementation of emergency procedures to Reliability Authority.
20. Coordinates use of controllable loads with Load Serving Entities (i.e., interruptible load that has been bid in as Interconnected Operations Services).

21. Implements emergency procedures as directed by the Reliability Authority.

After the hour

22. Confirms Interchange Schedules with Interchange Authorities after the hour for "checkout."

23. Confirms Actual Interchange with adjacent Balancing Authorities after the hour for "checkout."

Function

Function – Market Operations

Definition

Integrates energy, capacity, balancing, and transmission resources to achieve an economic, reliability-constrained dispatch of resources. The dispatch may be either cost-based or bid-based.

Tasks

1. Administer a market that provides capacity, energy, balancing resources, and other Ancillary Services subject to system requirements and constraints.

2. Arrange resources for congestion management.

3. Provide dispatch plans.

Special Considerations

The Market Operations function, its tasks, and the interrelationships with other entities is included in the Functional Model only as an interface point with other types of industry models.

Entity

Responsible Entity – Market Operator (or Resource Dispatcher)

Relationships with other Responsible Entities

Market Operator tasks and relationships are specific to a particular Market Operator and will depend on the market structure over which the Market Operator presides.

The Resource Dispatcher performs the same dispatch duties as the Market Operator, but in a non-market environment.

Function

Function – Resource Planning

Definition

Develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority Area.

Tasks

1. Maintain resource models and apply appropriate tools for the development of adequate resource plans.

2. Define and collect or develop demand and resource information required for planning purposes.

3. Provide capacity resource information to planning and operating functions and service functions.

4. Assist in the evaluation of the deliverability of resources to customers.

5. Include consideration of generation capacity from resources both within and outside of the Planning Authority Area.

6. Develop and report, as appropriate, on its resource plans to others for assessment and compliance with reliability standards.

7. Monitor and report, as appropriate, on its resource plan implementation.

Entity

Responsible Entity – Resource Planner

Relationships with other Responsible Entities

1. Coordinates the resource models with its Planning Authority.

2. Works and coordinates with Transmission Owners and Transmission Planners on the deliverability of resources to customers.

3. Reports its resource plan to the Planning Authority for assessment and compliance with reliability standards.

4. Reports on resource plan implementation to the Planning Authority.

5. Works with Planning Authority to identify potential alternative solutions to meet resource requirements.

6. Coordinates with and collects data for resource planning from the Load-Serving Entities, Generator Owners, Generator Operators, Transmission Owners, Transmission Operators, and Interchange Authorities.

7. Coordinates with Transmission Service Providers, Reliability Authorities, and Planning Authorities on resource adequacy plans as appropriate.

8. Coordinates with other Resource Planners within the Planning Authority Area to avoid the double-counting of resources.

Special Considerations

In some markets, it may be required that the same entity perform the Resource Planning Function and the Planning Authority Function. For example, the Resource Planner may also be the Planning Authority in those markets where there are no entities responsible or obligated to serve load. In these cases, the Resource Planning Function becomes a resource assessment function performed by the Planning Authority that identifies the need for additional resources to be provided by the market.

Function

Function – Transmission Operations

Definition

Operates or directs the operations of the transmission facilities.

Tasks

1. Maintain reliability of the transmission area in accordance with Reliability Standards.

2. Provide detailed maintenance schedules (dates and times)

3. Adjust dc ties within the transmission area for those Interchange Transactions that include the dc tie in the transmission path

4. Maintain defined voltage profiles.

5. Define operating limits, develop contingency plans, and monitor operations of the transmission facilities.

6. Provide telemetry of transmission system information

Responsible Entity – Transmission Operator

Relationships with other Responsible Entities

Ahead of Time

1. Receives maintenance requirements and plans from the Transmission Owner.

2. Defines operating limits, develops contingency plans, and monitors operations of the transmission facilities under the Transmission Operator's control and as directed by the Reliability Authority.

3. Provides operating information to the Reliability Authority.

4. Determines amount required and arranges for interconnected operations services from Generator Owners to ensure voltage support (e.g., reactive supply from generation resources) in coordination with the Reliability Authority.

5. Provides maintenance schedules and construction plans to Reliability Authority and Planning Authority.

6. Revises transmission maintenance plans as requested by the Reliability Authority and as permitted by agreements, recognizing that equipment maintenance must be performed as needed to ensure the life of the equipment and meet warranty requirements.

7. Provides Planning Authority information on capability to curtail (reduce) and shed load during emergencies.

Real Time

8. Operates or directs the operations of the transmission system within equipment and facility ratings established by the Transmission Owners and Generator Owners, and system ratings established by the Reliability Authority.

9. Deploys reactive resources from Transmission Owners and Generator Owners as Interconnected Operations Services to maintain acceptable voltage profiles.

10. Provides real-time operations information to the Reliability Authority.

11. Notifies Generator Operators of transmission system problems (e.g., voltage limitations or equipment overloads that may affect generator operations).

12. Requests Reliability Authority to mitigate equipment overloads. (e.g., redispatch, transmission loading relief).

13. Coordinates load shedding with, or as directed by, the Reliability Authority.

14. Directs Distribution Providers to shed load.

15. Implements dc tie operations for those ties under the Transmission Operator's purview as directed by the Transmission Service Provider.

Function

Function – Interchange

Definition

Authorizes implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures Interchange Transactions are properly identified for reliability assessment purposes.

Tasks

1. Determine valid, balanced, Interchange Schedules (validation of sources and sinks, transmission arrangements, interconnected operations services, etc.).

2. Verify ramping capability of the source and sink Balancing Authority Areas for requested Interchange Schedules

3. Collect and disseminate Interchange Transaction approvals, changes, and denials

4. Authorize implementation of Interchange Transactions

5. Enter Interchange Transaction information into Reliability Assessment Systems (e.g., the Interchange Distribution Calculator in the Eastern Interconnection)

6. Maintain record of individual Interchange Transactions

Responsible Entity – Interchange Authority

Relationships with other Responsible Entities

Ahead of Time

1. Verifies ramping capability for requested Interchange Schedules with Balancing Authorities.

2. Receives requests from Purchasing-Selling Entities to implement Interchange Transactions.

3. Submits all Interchange Transaction requests to the Reliability Authorities, Balancing Authorities, and Transmission Service Providers for approvals.

4. Receives confirmation from Transmission Service Providers of transmission arrangement(s).

5. Receives confirmation from Balancing Authorities of the ability to meet ramping requirements for submitted Interchange Schedules.

6. Receives information from Balancing Authorities of expected Interconnected Operations Services deployments that result in an Interchange Transaction (for example, an Interchange Schedule that is enabled by reducing load in a Balancing Authority Area, which frees up resources.)

7. Informs Purchasing-Selling Entities on implementation of load-provided Interconnected Operations Services that were bid into the market that result in an Interchange Transaction.

8. Provides approved, valid, and balanced Interchange Schedules to the Balancing Authorities for implementation.

Real Time

9. Provides Transmission Service Providers with the requested Interchange Transactions received from Purchasing Selling Entities using that Transmission Service Providers' transmission system.

10. Receives curtailments and redispatch implementation from Reliability Authorities.

11. Informs Transmission Service Providers, Purchasing-Selling Entities, Reliability Authorities, and Balancing Authorities of Interchange Schedule Implementations and Curtailments.

12. Receives information on Interchange Schedule interruptions due to generation loss or load interruption from the Balancing Authorities.

After the hour

13. Maintains and provides records of individual Interchange Transactions for the Balancing Authorities.

Function

Function – Transmission Planning

Definition

Develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority Area

Tasks

Develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within a portion of the Planning Authority Area.

Tasks

1. Maintain transmission system models (steady-state, dynamics, and short circuit) and apply appropriate tools for the development of transmission plans.

2. Define and collect transmission information and transmission facility characteristics and ratings.

3. Develop plans within defined voltage and stability limits and within appropriate facility thermal ratings.

4. Define system protection and control needs and requirements, including special protection systems (remedial action schemes), to meet reliability standards.

5. Determine TTC values[2] as appropriate.

6. Notify others of any planned transmission changes that may impact their facilities.

7. Evaluate and plan for transmission service and interconnection requests beyond one year.

8. Develop and report, as appropriate, on its transmission expansion plan for assessment and compliance with reliability standards.

9. Monitor and report, as appropriate, on its transmission expansion plan implementation.

[2] TTC is the total transfer capability and refers to the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions.

Entity

Responsible Entity – Transmission Planner

Relationships with other Responsible Entities

1. Provides transmission information, as appropriate, to planning and operating entities and service entities.

2. Coordinates and collects data as appropriate for system modeling, and plans transmission system modifications and expansion for Load-Serving Entities, Generator Owners, and Distribution Providers with other Transmission Planners, Transmission Owners, and Transmission Service Providers.

    a. Coordinates its transmission models with its Planning Authority.

    b. Notifies Generator Owners and Transmission Owners of any planned transmission changes that may impact their facilities.

    c. Coordinates with Resource Planners on the deliverability of new and proposed generation facilities, as appropriate.

3. Coordinates with Transmission Service Providers, Transmission Owners, Reliability Authorities, Planning Authorities, and other Transmission Planners on system limitations, transmission adequacy plans, and the determination of TTC values as appropriate.

4. Coordinates with its Planning Authority, other Planning Authorities, and other Transmission Planners within its Planning Authority Area on reliability issues, as appropriate, including

    a. Develops and reports its transmission expansion plan to its Planning Authority for assessment and compliance with reliability standards.

    b. Works with its Planning Authority to identify potential alternative solutions, including solutions proposed by stakeholders, to meet interconnected bulk electric system requirements.

    c. Reports on transmission expansion plan implementation to its Planning Authority.

Function

Function – Transmission Service

Definition

Administers the transmission tariff. Provides transmission services to qualified market participants under applicable transmission service agreements (for example, the *pro forma* tariff).

Tasks

1. Receive transmission service requests and process each request for service according to the requirements of the tariff.

    a. Maintain commercial interface for receiving and confirming requests for transmission service according to the requirements of the tariff (e.g., OASIS).

2. Approve or deny transmission service requests

3. Approve Interchange Transactions from transmission service arrangement perspective

4. Determine and post available transfer capability (ATC[3]) values.

5. Allocate transmission losses (MWs or funds) among Balancing Authority Areas.

[3] In this document, we use the term "ATC" in the generic sense to refer to the amount of transmission transfer capability that is offered under regulatory requirements.

Responsible Entity – Transmission Service Provider

Relationships with other Responsible Entities

Making Deals

1. Approves or denies transmission service requests from Purchasing-Selling Entities, Generator Owners, and Load-Serving Entities

Ahead of Time

2. Receives transmission expansion plans identified by the Planning Authority to help determine ability to accommodate long-term transmission service requests

3. Coordinates ATC with Reliability Authority (who may adjust operating reliability limits) and other Transmission Service Providers

4. Confirms Transmission Service requests to Interchange Authorities.

Real Time

5. Receives Interchange Transaction implementation and revisions from the Interchange Authorities

Function

Function – Transmission Ownership

Definition

Owns and maintains transmission facilities.

Tasks

1. Install and maintain transmission facilities according to prudent utility practice
2. Establish ratings of transmission facilities.
3. Develops interconnection agreements.

Responsible Entity – Transmission Owner

Relationships with other Responsible Entities

1. Coordinates with Transmission Planners and the Planning Authority and those entities (Generator Owners, other Transmission Owners, and Load-Serving Entities) desiring to interconnect facilities with the bulk electric systems.

2. Considers transmission expansion plans identified by the Planning Authority

3. Provides transmission expansion plans and changes to the Planning Authority and Transmission Planners.

4. Develops agreements or procedures with the Transmission Service Providers.

5. Develops operating agreements or procedures with the Transmission Operators and Reliability Authorities.

6. Provides transmission facility ratings to Transmission Operators, Reliability Authorities, Transmission Service Providers, Transmission Planners, and Planning Authority.

7. Provides construction plans to the Reliability Authority and Planning Authority

8. Provides maintenance plans to the Transmission Operator.

9. Develops agreements with adjacent Transmission Owners for the design, construction and operation and maintenance of joint transmission facilities.

Function

Function – Distribution

Definition

Provides and operates the "wires" between the transmission system and the end-use customer.

Tasks

1. Provide the interface between the transmission system and the end-use customer.

2. Provide voltage reduction and load shedding as necessary

Responsible Entity – Distribution Provider

Relationships with other Responsible Entities

Ahead of Time

1. Coordinates with Load-Serving Entities, Transmission Planners and their related Planning Authority on transmission expansion (e.g., coordination of system protection, special protection systems, load shedding, etc).

2. Works with end-use customers to identify new facility connection needs.

Real Time

3. Implements voltage reduction and sheds load as directed by Transmission Operators.

Special Considerations

The Distribution Provider provides the physical connection between the end-use customer and the electric system. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage.

The Distribution Provider is responsible for “local” safety and reliability. The Distribution Provider knows which customers are “critical” loads that should be shed only as a last resort, and provides the switches and reclosers for this emergency action.

Function

Function – Generator Operation

Definition

Operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services.

Tasks

1. Operate generators to provide energy or Interconnected Operations Services (or both) per contracts or arrangements
2. Formulate daily generation plan
3. Report operating and availability status of units and related equipment, such as automatic voltage regulators.
4. Develop annual maintenance plan for generating units and performs the day-to-day generator maintenance

Responsible Entity – Generator Operator

Relationships with other Responsible Entities

Ahead of Time

1. Provides generation commitment plans to the Balancing Authority after notification by Purchase-Selling Entities or Load Serving Entities of transaction approvals.
2. Provides Balancing Authority and Transmission Operator with requested amount of Interconnected Operations Services.
3. Provides operating and availability status of units to Reliability Authority and Balancing Authority for reliability analysis.
4. Reports annual maintenance plan for generating units to Balancing Authority.
5. Reports status of automatic voltage regulators to Transmission Operators.
6. Provides long-term unit maintenance schedules and unit retirement plans to Resource Planner and Planning Authority.

Real Time

7. Implements, upon direction by Balancing Authority, redispatch and interchange schedules
8. Provides real-time operating information to the Transmission Operator and Balancing Authority (to both the "host" Balancing Authority in which the Generator is physically located and the sink Balancing Authority in case the generation is dynamically transferred between Balancing Authority Areas).

Function

Function – Generator Ownership

Definition

Owns and maintains generating units.

Tasks

1. Establish generating unit ratings, limits and operating requirements.
2. Maintain its generation facilities according to prudent utility practices.
3. Verify generating unit performance characteristics

Responsible Entity – Generator Owner

Relationships with other Responsible Entities

1. Provides generator ratings, limits, and models to Transmission Planners and Planning Authorities.

Real Time

2. May deal directly[4] with either Load Serving Entities or Purchase-Selling Entities via bilateral contracts for energy, capacity, and Interconnected Operations Services products

3. Provides voltage support to Transmission Operators

[4] The Generator Owner can serve as its own Purchasing-Selling Entity, or be affiliated with a Load-Serving Entity.

Function

Function – Purchasing-Selling

Definition

Purchases or sells energy, capacity and all necessary Interconnected Operations Services as required. Purchasing-Selling Entities may be Marketers or Merchant Affiliates.

Tasks

1. Purchase and sell generation or capacity
2. Arrange Interchange Transactions
3. Arrange for transmission service (as required by tariffs)
4. Purchase and sell Interconnected Operations Services
5. Request implementation of Interchange Transactions

Responsible Entity – Purchasing-Selling Entity

Relationships with other Responsible Entities

Making Deals

1. Assists Load Serving Entities (LSE) define Interchange Transactions in meeting the LSE's needs.
2. Assists Load Serving Entities and other Purchasing-Selling Entities in supplying the Interconnected Operations Services needs of the Load-Serving Entities. (E.g., supplying regulation service via Interchange Transactions).
3. Arranges for transmission service from Transmission Service Providers and makes arrangements for Interconnected Operations Services with Generator Owners or Load-Serving Entities as applicable for Interchange Transactions.

Transaction Approval and Plans Ahead of Time

4. Submits requests to Interchange Authorities to implement Interchange Transactions.
5. Notifies Generator Operators and Load Serving Entities if Interchange Transaction requests are approved or denied.

Real Time

6. Notifies Interchange Authorities of Transaction Cancellations or Terminations.

Function

Function – Load-Serving

Definition

Secures energy and transmission service (and related Interconnected Operations Services) to serve the end-use customer.

Tasks

1. Collect individual and develop overall load profiles and forecasts of end-user energy requirements. (Daily, weekly, monthly, annually etc…)

2. Identify and provide facilities for load curtailment

3. Identify and provide facilities for self-provided Interconnected Operations Services

4. Negotiate agreements for needed energy, transmission service, and Interconnected Operations Services

5. Manage resource portfolios to meet demand and energy requirements of end-use customers.

Responsible Entity – Load-Serving Entity

Relationships with other Responsible Entities

Making Deals

1. Assists end-use customers develop and submit load profiles, plans, and forecasts as needed to the Balancing Authorities, Generator Owners, Generator Operators, Purchasing-Selling Entities, Planning Authority, Resource Planners, Transmission Planners, and Market Operator(s).
2. Assists Purchasing-Selling Entities in arranging for the delivery of energy to a specific metering point for loads via bilateral contracts
3. Assists Generator Owners and Generator Operators on behalf of end-use customers in securing energy and Interconnected Operations Services needed via bilateral contracts. (In this role the Load Serving Entity is acting like the Purchasing-Selling Entity.)

Ahead of Time

4. Arranges for transmission service via Transmission Service Providers.
5. Provides generation (affiliated and non-affiliated) commitments and dispatch schedules to the Balancing Authority.
6. Works with end-use customers to identify new facility connection needs
7. Works with Resource Planners to ensure planned purchases that cross Planning Authority Area boundaries are properly reported for system modeling and reliability assessments
8. Coordinates with Transmission Planner and the Planning Authority on data requirements for system modeling and transmission expansion.
9. Works with the Balancing Authorities and Transmission Operators for implementing load shedding during emergency conditions and to provide load interruption capability as an Interconnected Operations Service.

Real Time

10. Assists Distribution Providers in implementing load shedding during emergency conditions and Balancing Authorities to provide load interruption capability as an Interconnected Operations Service

Function

Function – Compliance Monitoring

Definition

Monitors, reviews, and ensures compliance with Reliability Standards and administers sanctions or penalties for non-compliance to the standards.

Tasks

1. Audit and document compliance of all registered Responsible Entities to Reliability Standards
2. Recommend sanctions or penalties for non-compliance with Reliability Standards

Responsible Entity – Compliance Monitor

Relationships with other Responsible Entities

1. Receives oversight direction from the Standards Developer for consistency
2. Monitors all responsible entities as required by Reliability Standards and Certification Criteria.
3. Provides compliance information to the Standards Developer and others as appropriate

Function

Function – Standards Development

Definition

Develops, maintains, and implements Reliability Standards to ensure the reliability of the interconnected bulk electric transmission systems in the United States, Canada, and Baja California Norte, Mexico.

Tasks

1. Develop Reliability Standards for the planning and operation of the interconnected bulk electric transmission systems that serve the United States, Canada, and Baja California Norte, Mexico.
2. Develop compliance measurement and enforcement procedures for each Reliability Standard.
3. Develop Criteria and Certification Procedures for Balancing, Interchange, and Reliability Authorities, Transmission Operators, and others as needed.
4. Provide for appeals and dispute resolution procedures.

Responsible Entity – Standards Developer

Relationships with other Responsible Entities

Coordinates with other standards-approving organizations

Functional Model Approval Procedure

Changes to the Functional Model are approved by the standing committees and the board of trustees. The Functional Model is the framework for the Reliability Standards, and the functions, their definitions, and interrelationships must be observed as SARs and Standards are drafted. Doing otherwise would cause conflicts among the Reliability Standards as they are developed over time.

The Functional Model Working Group considers all requests to revise the Functional Model, and manages the revision process:

1. Functional Model Working Group reviews the proposed revision to the Model, considering current Reliability Standards, and SARs and Standards being drafted. The Working Group will work with the individual or group requesting the change to the Model.

2. Working Group posts revision for public comment for 45 days.

3. Working Group submits revision to the standing committees for review and approval. (The revision will include an implementation date for the revisions.)

4. Working Group submits standing committee-approved revision to the NERC Board of Trustees for approval.

5. NERC staff posts revised Functional Model.

NERC Reliability Functional Model
Technical Document

- ***Entity Responsibilities and Interrelationships***
- ***Technical Discussions***

This document is a companion to Version 2 of the Functional Model and includes explanations, opinions, and discussions of the Functional Model Review Task Group and Planning Reliability Model Task Force.

Contents

Introduction

As it spent many months discussing and debating the details of the Functional Model, the Functional Model Review Task Group prepared this companion document to record its thoughts and conclusions. The Task Group hopes this companion to the Functional Model will help the reader better understand the functions and the relationships between and among the responsible entities that perform the functions.

Section 1 provides details about each of the responsible entities. Some entities, such as the Transmission Owner or Purchasing-Selling Entity, are adequately described in the Functional Model document, and there is little detail to add here. Others, such as the Interchange Authority and Balancing Authority, are more complex both unto themselves and in their relationship with other functions, and this document provides additional explanations. Descriptions of the three new Planning functions and their interrelationships between and among these functions and the other functions in the Model is included in this section.

Section 2 includes technical discussions on related topics and tasks such as managing bilateral transactions, task assignment and delegation, the Planning functions, and boundary conditions. Many of these topics are mentioned in the Functional Model, but the details may not be obvious.

The discussion of Market Structures helped the Task Group understand the various types of markets and pools and conclude that the Model was not dependent on any particular market structure or pool "depth." The Task Group retained these discussions for future reference.

The Task Group spent considerable time deliberating over the role of a "scheduling agent" or the notion of non-coincident resource dispatcher (Market Operator) and Balancing Authority Areas, only to decide that these functions were not readily separable from the Balancing Authority. The Task Group kept these discussion as well.

Section 1 – Entity Responsibilities and Interrelationships

1. Reliability Authority

See "Electrical and Physical Boundaries" for a description of the Reliability Authority Area.

The Reliability Authority is the highest-level authority and can direct all operational reliability functions within its **Reliability Authority Area**[1] The Reliability Authority determines Interconnected Reliability Operating Limits[2] based upon Transmission and Generation Owners' specified equipment ratings, system operating limits calculated by the Transmission Operator(s), plus system studies. The Reliability Authority monitors its Reliability Authority Area to ensure the system operates within its thermal, voltage, and stability limits. The Reliability Authority monitors and ensures transmission system reliability at all times. It also specifies the requirements for Interconnected Operations Services to ensure transmission reliability.

The Reliability Authority's purview must be broad enough to enable it to calculate Interconnection Reliability Operating Limits, which may be based on the operating parameters of other transmission systems beyond the Transmission Operator's vision. The Transmission Operator is responsible for the reliability of its "local" transmission system, and may not be aware that its system is violating an Interconnection Reliability Operating Limit. Therefore, the Reliability Authority may direct the Transmission Operators or Balancing Authorities to take action to mitigate Operating Reliability Limits.

The Reliability Authority also assists the Transmission Operator in relieving equipment or facility overloads through transmission loading relief measures if market-based dispatch procedures are not effective.

Role in approving Transactions. The Reliability Authority approves Transactions with respect to transmission reliability and provides its approval or denial to the Interchange Authority.

[1] There is a "reliability function" performed at all levels of the transmission system. For example, the Transmission Operator provides an operating reliability function that covers a more "local" level. This is briefly mentioned in the Transmission Operator section on Page 5.

[2] **Interconnection Reliability Operating Limit (IROL).** The value (such as MW, MVar, Amperes, Frequency, or Volts) derived from, or a subset of, the system operating limits, which if exceeded, could expose a widespread area of the bulk electrical system to instability, uncontrolled separation(s) or cascading outages. (*Excerpt from Operating Limits Definition Task Force report to the NERC Operating Committee, March 2003*)

Day-ahead analysis. The Reliability Authority will receive the dispatch plans from the Balancing Authority on a day-ahead basis.[3] The Reliability Authority will then analyze the dispatch from a transmission reliability perspective. If the Reliability Authority determines that the Balancing Authority's dispatch plans will jeopardize transmission reliability, the Reliability Authority will work with the Balancing Authority to determine where the dispatch plans need to be adjusted. The Reliability Authority has the "final say" in the generation dispatch.

The Reliability Authority obtains generation and transmission maintenance schedules from Generator Operators and Transmission Operators. The Reliability Authority can deny a transmission outage request if transmission system reliability would be adversely affected.

Emergency actions. The Reliability Authority is responsible for real-time system reliability, which includes calling for the following emergency actions:

- Curtailing Transactions
- Directing redispatch to alleviate congestion
- Mitigating energy and transmission emergencies, and
- Ensuring energy balance and Interconnection frequency.

The Reliability Authority, in collaboration with the Balancing Authority and Transmission Operator, can invoke public appeals, voltage reductions, demand-side management, and even load shedding if the Balancing Authority cannot achieve resource-demand balance.

[3] These dispatch plans may have been developed by the Market Operator.

2. Planning Authority

The Planning Authority ensures a long-term (generally 1 year and beyond) plan is available for adequate resources and transmission within its Planning Authority Area. That area encompasses a defined area and the customer demands therein. It may be smaller than, equal to, or larger than that of a Reliability Authority or a Regional Reliability Council.

In providing analyses and reports on the long-term resource and transmission plan(s) for the Planning Authority Area, the Planning Authority may also:

- Assess and publish industry trends (demands, transmission, and resources) within the Planning Authority Area in the time frame of generally 1 year and beyond, and

- Provide reports and data, as requested or required, to the Standards Developer, Compliance Monitor, Regional Councils, NERC, regulatory authorities, and governmental agencies.

Even when the transmission and resource plans developed by the Transmission Planners and Resource Planners comply with reliability standards, the Planning Authority will monitor the implementation of the transmission and resource plans, including the tracking of generating capacity, demand program, and transmission in-service dates. It will also evaluate the impact of revised transmission and generator in-service dates on transmission and resource adequacy.

In its evaluation of resource plans, the Planning Authority will likely review the conversion of various resource adequacy requirements and methodologies into equivalent resource capacity (or reserve) margins (or requirements) for use within the Planning Authority Area.

3. Balancing Authority

See "Electrical and Physical Boundaries"

The Balancing Authority operates within the metered boundaries that establish the **Balancing Authority Area**. Every generator, transmission facility, and end-use customer must be in a Balancing Authority Area. The Balancing Authority's mission is to maintain the balance between loads and resources in real time within its Balancing Authority Area by keeping its actual interchange equal to its scheduled interchange and providing its frequency bias obligation. The load-resource balance is measured by the Balancing Authority's Area Control Error (ACE) defined as:

$$ACE = (I_A - I_S) - 10\beta(f_A - f_S)$$

Perfect balance occurs when ACE = 0; however, perfect balance requires perfect resource control, which is impossible. Therefore, NERC's reliability standards require that the Balancing Authority maintain its ACE within acceptable limits.

Maintaining resource-demand balance within the Balancing Authority Area requires four types of resources management, all of which are the Balancing Authority's responsibility:

1. Frequency control through tie-line bias
2. Regulation service deployment
3. Load-following through generator dispatch
4. Interchange implementation

See "Task Responsibilities and Delegation"

Regulation service deployment. To maintain its ACE within these acceptable limits, the Balancing Authority controls a set of generators within its Balancing Authority Area that are capable of providing regulation service[4].

Generator dispatch. The Functional Model assumes that the organization that serves as the Balancing Authority is also performing the generator commitment and economic dispatch. Included in the commitment and dispatch tasks is the designation of those resources that are available for regulation service.

Interchange. The Balancing Authority receives Interchange Schedules from one or more Interchange Authorities, and enters those Transactions into its energy management system.

Generation commitment and schedules from Load-Serving Entities. The Balancing Authority also receives generator commitment and dispatch schedules from the Load-Serving Entities who have bilateral arrangements for generation within the Balancing Authority Area. The Balancing Authority provides this commitment and dispatch schedule to the Reliability Authority.

[4] Regulation service is one of the NERC-defined Interconnected Operations Services. The Balancing Authority is said to "deploy" this service when it controls the generators that are available for regulation.

Role in approving Transactions. The Balancing Authority approves bilateral transactions with respect to the ramping requirements of the generation that must increase or decrease to implement those transactions. The Balancing Authority provides its approval or denial to the Interchange Authority.

Energy Emergencies. In the event of an Energy Emergency, the Balancing Authority can implement public appeals, demand-side management programs, and, ultimately load shedding[5]. Obviously, it must do this in concert with the Reliability Authority.

See "Managing Bilateral Transactions"

Failure to balance. The Balancing Authority must take action, either under its own initiative or direction by the Reliability Authority, if the Balancing Authority cannot comply with NERC's reliability standards regarding frequency control and Area Control Error.

[5] The Balancing Authority can not implement voltage reductions because it does not control the distribution system. Voltage reductions are accomplished by the Transmission Operator under the direction of the Reliability Authority

4. Resource Planner

The Resource Planner develops a long-term (generally 1 year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority Area.

This Resource Planning function may be performed by one or more Resource Planners within the Planning Authority Area. The resource plans may include generation capacity from resources outside of the Planning Authority Area.

In some markets it may be required that the same entity be the Resource Planner as well as the Planning Authority. For example, the Resource Planner may also be the Planning Authority in those markets where there are no entities responsible or obligated to serve load. In these cases, the Planning Authority identifies the need for additional resources to be provided by the market.

In developing resource plans, the Resource Planner will also collect and develop related resource information for planning purposes from other entities, including:

- Demand and energy end-use customer forecasts from the Load-Serving Entities,
- Demand management data and programs,
- Generator unit performance characteristics and capabilities from Generator Owners and others, and
- Information on existing and proposed new capacity purchases and sales.

In developing and reporting its resource plans to the Planning Authority for assessment and compliance with reliability standards, the Resource Planner will be expected to:

- Identify those resources that may be considered firm resources (e.g., under contract, under construction, environmental permits in place, etc.),
- Verify that resource plans meet adequacy resource requirements or identify resource deficiencies, and
- Work with the Planning Authority to identify potential alternative solutions to meet resource requirements should the resource plans be deficient.

In reporting on resource plan implementation to the Planning Authority, the Resource Planner should provide:

- The tracking of capacity and demand program in-service dates, and
- An evaluation of revised transmission and generation in-service dates on resource adequacy.

5. Transmission Operator

The Transmission Operator is designated by the Transmission Owner, and operates or directs the operation of the transmission facilities, and is responsible for local reliability functions. The Transmission Operator is responsible for reliably operating the transmission system within its purview by maintaining proper voltage profiles and honoring transmission equipment limits established by the Transmission Owner. The Transmission Operator is under the Reliability Authority's direction and can take action, such as implementing voltage reductions, to help mitigate an Energy Emergency.

Maintenance. The Transmission Owner provides the overall maintenance plans and requirements for its equipment, specifying, for example, maintenance periods for its transformers, breakers, and the like. The Transmission Operator must then develop the detailed maintenance schedules (dates and times) based on the Transmission Owner's maintenance plans and requirements, and provide those schedules to the Reliability Authority and others as needed.

The Transmission Operator may also physically provide or arrange for transmission maintenance, but it does this under the direction of the Transmission Owner who is ultimately responsible for maintaining its transmission facilities.

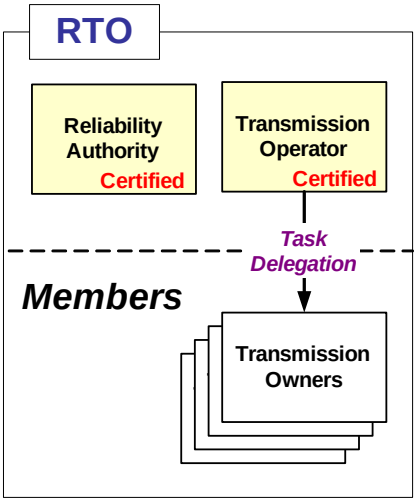


Figure 1 - Transmission Operator bundled with Reliability Authority.

Bundled with the Reliability Authority or Transmission Owner

The Transmission Operator may be a separate organization. However, in many cases the Transmission Operator is bundled with either the Reliability Authority or the Transmission Owner.

Bundled with Reliability Authority. For example, consider an RTO with several members (Figure 1). The RTO registers with NERC as a Reliability Authority and Transmission Operator and is NERC-certified for both. The RTO then delegates some of the Transmission Operator tasks as appropriate to its members. Regardless of this delegation, the RTO remains the entity responsible for complying with all reliability standards associated with the Reliability Authority and Transmission Operator, and would be NERC-certified for both.

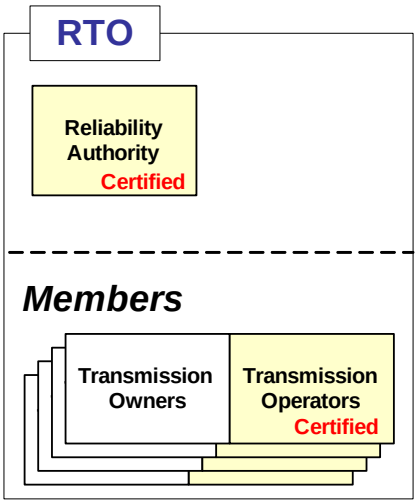


Figure 2 - Transmission Operator bundled with the Transmission Owner.

Bundled with the Transmission Owner. In other situations, the RTO registers with NERC as the Reliability Authority, and its members register as Transmission Owners and Transmission Operators. In this case, the RTO is responsible for complying with all reliability standards associated with the Reliability Authority function and would be a NERC-certified RA. The RTO members, who are typically the Transmission Owners, would be responsible

for complying with all reliability standards associated with the Transmission Operator, and would be NERC-certified.

6. Interchange Authority

See "Managing Bilateral Transactions"

The Interchange Authority provides a service very similar to the Tag Authority that is now assigned to the Sink Control Area. That is, it collects approvals or denials from the other reliability functions — Reliability and Balancing Authorities, and Transmission Service Providers — and verifies the validity of the source and sink.

The Scheduling Agent performs a service for a group of Balancing Authorities. See "Managing Bilateral Transactions" for additional details.

The Interchange Authority provides the Balancing Authority with the individual bilateral Interchange Transactions as well as the "net" of those Transactions, which is the net interchange from that Interchange Authority that the Balancing Authority enters into its energy management system. The Balancing Authority must track the individual Transactions in case one or more of them are curtailed by the Reliability Authority, or by the Balancing Authority in those cases where the generator or load is interrupted. The net Interchange Schedule is used by the Balancing Authority for checkout with the Interchange Authority.

All bilateral Transactions *that cross both a Balancing Authority Area boundary* must be authorized by the Interchange Authority.

The Interchange Authority function is not needed to manage Bilateral Transactions that are internal to a Balancing Authority Area.

Assessing ramping capability and reliability. The Balancing Authority (or Scheduling Agent for those cases where the transaction is between Resource Dispatch Areas with multiple Balancing Authority Areas) also approves the capability to ramp the Transactions in or out and the Reliability Authority performs a reliability assessment to make sure the Transaction will not jeopardize the integrity of the Transmission System.

Confirming transmission arrangements. The Transmission Service Provider is responsible for approving the Transaction by confirming to the Interchange Authority that there is a valid transmission service arrangement. During the authorization process, the Interchange Authority sends the "tag"[6] to each Transmission Service Provider on the scheduling path. Thus, even if the Interchange Authority had determined that the source and sink are "valid" generator and load busses, if the Transmission Service Provider, upon reviewing the "tag," does not believe the source and sink information is equivalent to the source-sink information that was provided when the transmission service was arranged, then it can inform the Interchange Authority that it (the TSP) does not approve the Transaction.

Ensuring balanced, valid Interchange Transactions. The Interchange Authority also ensures that the resulting Interchange Transactions are balanced and valid prior to physical delivery. This means:

1. The source MW must be equal to the sink MW (plus losses if they are "self-provided"), and

[6] We use the term "tag" because of its familiarity. It refers in the general sense to the collection of data that defines a Transaction, not specifically to the "E-tag" or ERCOT tagging system.

2. The Transactions are between valid sources and sinks (see "Handling Partial Path Transmission Arrangements below), and
3. There is a (continuous) transmission arrangement from the Source to the Sink.

Only when it receives approvals from the Transmission Service Provider, Balancing Authority, and Reliability Authority, does the Interchange Authority direct the source and sink Balancing Authorities to implement the Transaction. If any of these three — TSP, BA, or RA — do not approve the Transaction, then the Interchange Authority cannot authorize the transaction.

Handling "Partial Path" Transmission Arrangements. The NERC Operating Manual defines a **Transaction** as "An agreement arranged by a Purchasing-Selling Entity to transfer energy from a seller to a buyer." For the purposes of the Functional Model, it is important that adequate information be provided to enable the Reliability Authority to properly assess the impact of a Transaction ready to "go physical" on the Interconnection. This does not mean that the Functional Model prohibits partial path transmission arrangements. It does mean that when the Purchasing-Selling Entity is ready for the Transaction to be handed off to the Interchange Authority for physical implementation, the PSE must "link" those partial paths so that the Reliability Authority can study the effects of the transaction on the transmission system under its purview. Until the Reliability Authority has a valid source and sink on which to base its study, knowing the partial path is of no use, and there is no reason for the Purchasing-Selling Entity to submit a partial path arrangement to the Interchange Authority.

Curtailments. The Interchange Authority coordinates curtailments ordered by the Reliability Authority by notifying the Balancing Authorities, Transmission Service Providers, and Purchasing-Selling Entities. The Interchange Authority also communicates and coordinates the resulting modified Interchange Schedules that resulted from the curtailments. This should also help remedy the myriad problems with inadvertent balancing that the Eastern and Western Interconnections are experiencing today.

7. Transmission Planner

In developing plans for transmission service and interconnection requests beyond one year, the Transmission Planner is expected to coordinate and jointly plan with other Transmission Planners, as appropriate, to ensure new facilities do not adversely affect the reliability of neighboring transmission systems.

In reporting its transmission expansion plan to the Planning Authority, the Transmission Planner is also expected to verify that its plans for new or reinforced facilities meet reliability standards or identify the transmission deficiencies. The Transmission Planner is to work with the Planning Authority to identify potential alternative solutions, including solutions proposed by stakeholders, to meet interconnected bulk electric system requirements.

The Transmission Planner, in connection with monitoring and reporting its transmission plan implementation to the Planning Authority, should address:

- Transmission facility in-service dates,
- Coordination with Transmission Operators on projects requiring transmission outages that can impact reliability and firm transactions, and
- The impact of revised transmission in-service dates on transmission and resource adequacy.

8. Transmission Service Provider

The Transmission Service Provider is designated by the Transmission Owner, and authorizes the use of the Transmission System. In most cases, the Transmission Service Provider is the tariff administrator.

See "Interchange Authority," Section "Confirming transmission arrangements"

Role in approving Transactions. The Transmission Service Provider approves Interchange Transactions by comparing the transmission service previously arranged by the transmission customer (Purchasing-Selling Entity, Generator Owner, Load-Serving Entity) with the transmission information supplied by the Interchange Authority. The Transmission Service Provider then provides its approval or denial to the Interchange Authority.

Providing Transmission Service. As its name implies, the Transmission Service Provider is responsible for providing transmission service to transmission customers, such as Generator Owners, Load-Serving Entities, and Purchasing-Selling Entities. The Transmission Service Provider determines Available Transfer Capability and coordinates ATC with other Transmission Service Providers. The Transmission Service Provider manages the requests for transmission service according to the Transmission Owner's tariff, and within the operating reliability limits determined by the Reliability Authority. The Transmission Service Provider does not itself have a role in maintaining system reliability in real time — that is the Reliability Authority's and Transmission Operator's responsibility.

The Transmission Service Provider arranges for transmission loss compensation with the Balancing Authority.

9. Transmission Owner

The Transmission Owner owns and maintains its transmission facilities. It also specifies equipment operating limits, and supplies this information to the Transmission Operator, Reliability Authority, Transmission Planner, and Planning Authority.

In many cases, the Transmission Owner would have contracts or interconnection agreements with generators or other transmission customers that would detail the terms of the interconnection between the Owner and customer.

See "Transmission Operator," Section "Bundling with the Reliability Authority or Transmission Owner"

Relationship with the Transmission Operator. The Transmission Owner may also operate its transmission facilities and register with NERC as a Transmission Operator. In that case, it would also need to apply for organization certification as a Transmission Operator.

On the other hand, the Transmission Owner may arrange for another organization to operate its transmission facilities.

10. Distribution Provider

The Distribution Provider provides the physical connection between the end-use and the electric system. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage.

The Distribution Provider is responsible for "local" safety and reliability. The Distribution Provider knows which customers are "critical" loads that should be shed only as a last resort, and provides the switches and reclosers for this emergency action. The Distribution Provider may need to demonstrate load-shedding capability to the Balancing Authority and Transmission Operator.

We may find the same organization serving as the Distribution Provider and Load-Serving Entity, but they may be separate organizations as well. Unlike the Load-Serving Entity, the Distribution Provider does not take title to any energy. However, in many cases an organization, such as a vertically integrated utility, may bundle these functions together.

11. Generator Operator

The Generator Owner may also operate its generating facilities or designate a separate organization to perform this Generator Operator service.

12. Generator Owner

The Generator Owner owns and maintains its generation facilities. It also specifies equipment operating limits, and supplies this information to the Generator Operator, Reliability Authority, Transmission Planning Function, and Planning Authority.

In many cases, the Generator Owner would have contracts or interconnection agreements with Transmission Owners that would detail the terms of the interconnection between these parties.

Relationship with the Generator Operator. The Generator Owner may also operate its generation facilities or arrange for another organization to operate those facilities.

13. Purchasing-Selling Entity

The Purchasing-Selling Entity arranges for and takes title to energy that it secures from a resource for delivery to a Load-Serving Entity. The PSE also arranges for transmission service with the Transmission Service Provider(s) that connect the resource to the LSE.

The Purchasing-Selling Entity implements a bilateral Transaction between Balancing Authority Areas by submitting the transaction information to the Interchange Authority.

14. Load-Serving Entity

The Load-Serving Entity provides energy to its end-use customers, but does not include distribution services ("wires").

The Load-Serving Entity will either own generation, contract with Generator Owners for capacity and energy to serve the LSE's customers, or purchase capacity and energy from non-affiliated Generator Owners through a Purchasing-Selling Entity (or Market Operator), or a combination of these three options. The Load-Serving Entity is responsible for dispatching its affiliated generation resources to meet its load and has the "initial say" in that dispatch or redispatch.

The Load-Serving Entity will report its generation (affiliated and non-affiliated) arrangements to serve load to the Balancing Authority, who forwards this information to the Reliability Authority, sometime before the generation is actually dispatched, perhaps noon the day before for day-ahead analysis.

The LSE will also contract for Interconnected Operations Services (through the Market Operator if it is part of a market or pool) or directly from Generator Owners. The LSE may also provide certain Interconnected Operations Services itself.

15. Compliance Monitor

Today, the Regional Councils are the Compliance Monitors in NERC. The Regional compliance plans are audited by the NERC organization.

In those situations where the Compliance Monitor is also the organization performing a reliability service or operating function (such as a Regional Council that is also the Reliability Authority), then the Compliance Monitor for that function should be a third party that is unaffiliated with that organization.

16. Standards Developer

The Reliability Standards Developer includes NERC and the Regional Councils; however, the Functional Model is written to accommodate any organization that develops reliability standards.

Section 2 – Technical Discussions

1. Functions, Tasks, Responsible Entities, and Organizations – The Guiding Principles

While reviewing Version 1 of the Functional Model, the Functional Model Review Task Group heard many complaints that the Model improperly conflated functions and organizations, and did not clearly explain how tasks could be delegated to other organizations. The Functional Model Review Task Group addressed these concerns by:

1. Reformatting the Functional Model document to clearly delineate between the tasks that comprise *Functions* and the interrelationship among *Responsible Entities,* and

2. Listing the Guiding Principles upon which the Model itself is based.

Guiding Principles. The Guiding Principles listed in the Functional Model document are not new—indeed, the Control Area Criteria Task Force (CACTF) based Version 1 of the Model on these very principles, but didn't specifically list the principles themselves in the Functional Model document. The Task Force assumed these principles would be understood once the Model was explained, but it has since became obvious that was not the case.

As the CACTF assembled the Model's functions, it kept these Guiding Principles in mind. It built each *function* on a set of *tasks* so closely related to one another that separating those tasks would impair the integrity of the function.

Likewise, the Task Force believed that an organization that performed a function must be responsible for each task within that function. For example, the Balancing Function includes generation commitment, dispatch, regulation, frequency response, and the integration of scheduled interchange. The entity responsible for maintaining the resource-demand balance within its metered boundaries must be responsible for ensuring that all of these tasks are performed. It may delegate one or more of these tasks to others, but it can not delegate its responsibility. Allowing an entity to assign its responsibilities to others could result in uncertainty as to who is actually responsible for resource -demand balance, which, in turn, makes compliance enforcement difficult, if not impossible.

The Functional Model Review Task Group continues to support these Guiding Principles and believes they are so integral to understanding the Functional Model that they are specifically listed in the Functional Model document itself.

The Model provides the framework on which the NERC reliability standards are based. These standards rely on the stability and integrity of the Model to provide this foundation, and the Functional Model Review Task Group believes NERC must adhere to these Guiding Principles as the Functional Model is further developed and revised. These Principles should not be compromised for short-term expediency.

Functions. The FMRTG reformatted the Functional Model document to delineate between Functions and Responsible Entities. The diagram of the Model now includes two names within each function box as shown in Figure 3. The functions is shown in a larger typeface with the associated Responsible Entity underneath.

Responsible Entities. Organizations, such as Regional Transmission Organizations, Control Areas, Regional Councils, and Transmission Operators, will register with NERC as *Responsible Entities* by identifying which functions they perform.

For example, an RTO (organization) may register with NERC to be a Reliability Authority, Balancing Authority, and a Transmission Service Provider. Thus we say that the RTO is the *Responsible Entity* for the Operating Reliability, Balancing, and Transmission Service *functions*. We also use the expression that the RTO has "rolled up" these three functions and is responsible for ensuring that the tasks within each of those functions are performed.

See "Rollup Examples"

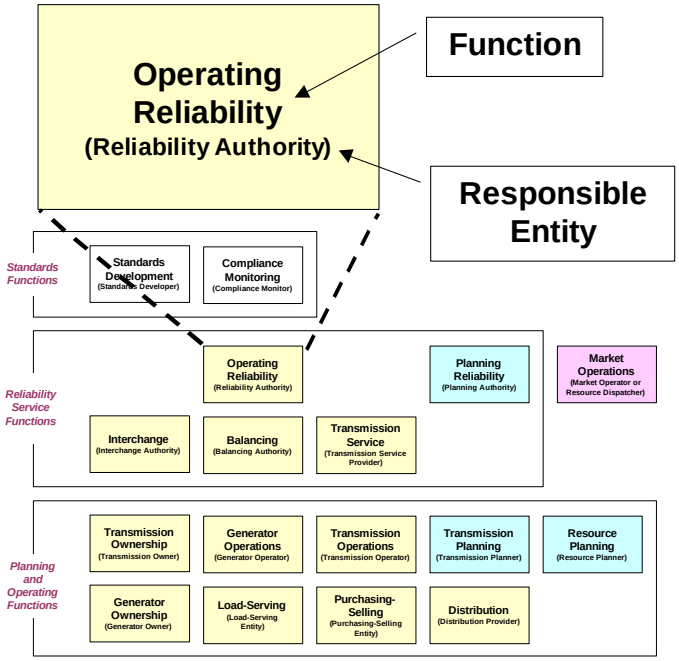


Figure 3 - The Functional Model depicts Functions and Responsible Entities

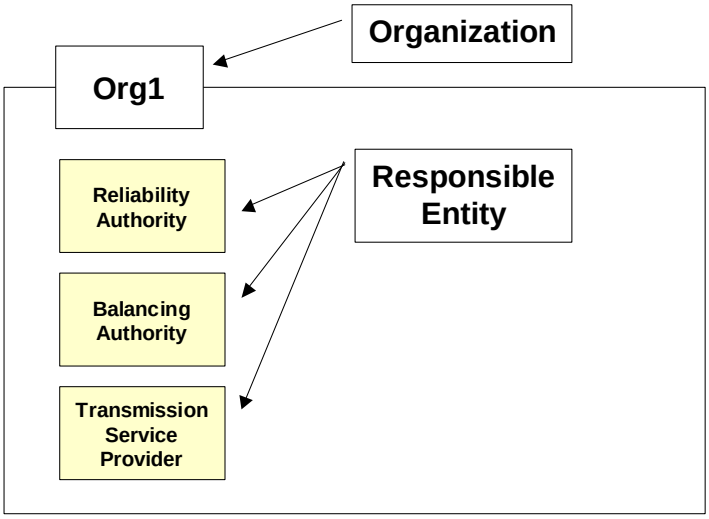
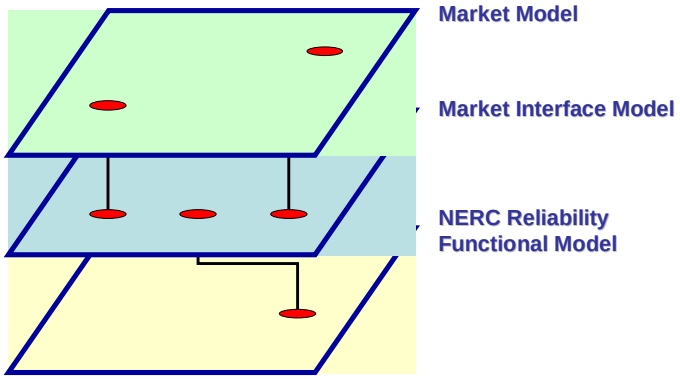


Figure 4 – Organizations are the entities responsible for performing the functions that they "roll up."

2. The Market Operator

The Market Operator is included in the Functional Model to provide an interface point with other functional models. For instance, the North American Energy Standards Board (NAESB) may develop a commercial model that explains the tasks and relationships necessary for electronic scheduling.



See next section on "The Functional Model and Market Structures"

Market Operators vary in design and responsibilities, but many perform the resource dispatch ("economic dispatch") tasks under a set of market rules that are established by a state, federal, or provincial regulator. Following its market rules, the Market Operator calculates a generation dispatch to meet the load forecast for the current dispatch cycle (typically five minutes or longer). This generation dispatch is usually a function of:

1. The generators' incremental costs or bids ("merit order"), and
2. Limitations caused by transmission congestion.

Taken together, this constitutes a "security constrained" dispatch.

Relationship between the Market Operator and Balancing Authority. The Functional Model Review Task Group spent considerable time discussing the feasibility of the Market Operator as an entity separate from the Balancing Authority, especially when the Task Group realized that at least one organization was planning to include several control areas into a single market area. To understand the Task Group's conclusions, it's important to understand that the Market Operator, in performing the resource dispatch tasks, is responsible for:

1. Determining the generation plan (unit commitment) ahead of time,
2. Integrating scheduled interchange into that generation plan,
3. Designating which generators are available for regulation service, and
4. Dispatching generation in real time.

Performing any of these tasks improperly can result in an imbalance between resources and demand within the market area. For example, if the Market Operator does not commit enough generation, or incorrectly dispatches the generation, or does not properly integrate bilateral interchange transactions that source from or sink into the market area, the market area's generation may not be sufficient in real time to meet its demand. Furthermore, if the Market Operator does not provide for sufficient regulation resources, the Balancing Authorities within that market area, in turn, might not successfully maintain their scheduled interchange within reliability standards, and Interconnection frequency will be affected.

Therefore, the Functional Model Review Task Group believes that if the Market Operator performs a real-time resource dispatch, the organization that serves as the Market Operator must also be the Balancing Authority to mitigate Market Operator dispatch or scheduling errors that could affect Interconnection frequency**.** This has three important implications:

1. The Market Area is the same as the Balancing Authority Area.

2. Bilateral transactions *within* the Market Area do not require the authorization of the Interchange Authority.

3. The Functional Model is unaffected by market rules or structures.

Non-market Resource Dispatcher. As explained in the next section on "The Functional Model and Market Structures," in the traditional vertically integrated organization, the "Resource Dispatcher" performs the economic dispatch tasks. The Functional Model Review Task Group assumes that, for the same reasons explained above, the organization that serves as the Resource Dispatcher must also be the Balancing Authority.

The Task Group is also aware of some organizations that serve as the Balancing Authority with multiple Resource Dispatchers. The Task Group believes that relationship is feasible because any generation-demand mismatches that might result from dispatch errors would be mitigated by the Balancing Authority.

3. The Functional Model and Market Structures

This section explains how the Functional Model accommodates various market structures by examining these structures from two perspectives:

1. The **dispatch protocol** that the Resource Dispatcher follows, which varies from cost-based to bid-based. When the Resource Dispatcher operates a bid-based generation market, then we call it a Market Operator.

2. The **depth of the resource pool** under the Resource Dispatcher's purview that supplies the Load-Serving Entities.

Generation Dispatch Protocol

The dispatch protocol is the method that determines the merit order of the generation dispatch. Generally, dispatch protocols are either cost-based or bid-based, depending on the market rules established by the regulatory authority. The dispatch algorithm for cost-based and bid-based dispatch is generally the same, which is why the Functional Model can accommodate either method.

Cost-based dispatch. Traditional, vertically-integrated utilities typically dispatch their resources based on actual fuel cost plus operations and maintenance costs and losses. The regulatory authority, such as the state public utility commission, might specify the accounting rules for calculating these costs. In this case, the "market" is cost-based, and the Resource Dispatcher determines the generator dispatch according to the same incremental cost ("lambda"). Transmission constraints can cause the incremental costs to be different on either side of the constraint. Thus, the lambda can vary by location.

Bid-based market dispatch. In some areas of the U.S. and Canada, market protocols provide Generator Owners the ability to bid into the market. In those cases, Generator Owners will submit bids via the Generator Operators to the Resource Dispatcher who operates the market. The market protocols are established by the regulatory authority, such as the Federal Energy Regulatory Commission. **In this situation, the Resource Dispatcher is the Market Operator.** The Market Operator, in turn, provides the Generator Operators with the generator dispatch so that the generators within the market footprint operate at the same incremental bid. As with the traditional cost-based incremental dispatch, transmission constraints may cause the price to vary by location. This is called "Locational-based Marginal Price," or LMP.

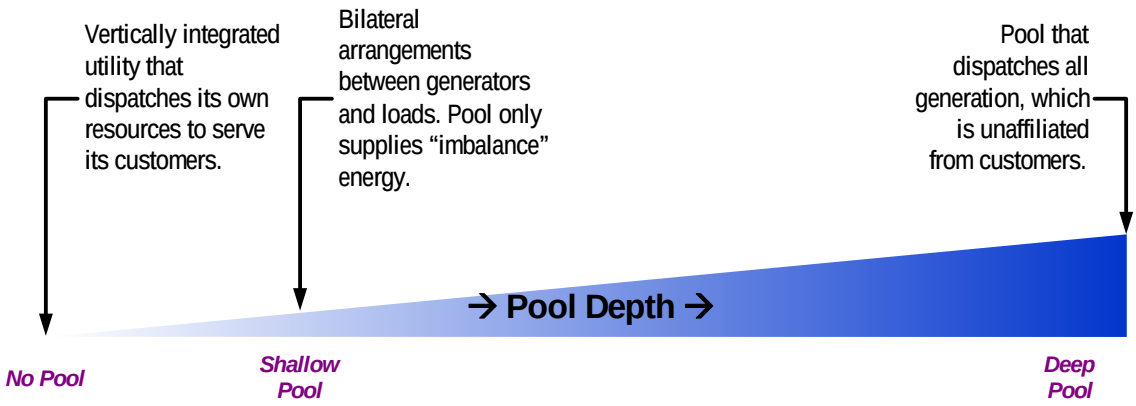
If the Market Area includes more than one Balancing Authority Area, then the Market Operator will also provide each Balancing Authority with the net "interchange" schedule that results from the resource dispatch ("Resource Dispatch Interchange Schedule"). Each Balancing Authority's Resource Dispatch Interchange Schedule will be an import or export to the Dispatch Area, **and the sum of all Resource Dispatch Interchanges within the Resource Dispatch Area must add to zero at each dispatch cycle**.

The Market Operator's generation dispatch will be constrained from time to time by transmission congestion as well as voltage and stability limits established by the Transmission Operator and Reliability Authority. Thus, the Market Operator performs both a market service as well as a reliability service.

Generation Pools

By generation "pool" we mean a collection of generators that are dispatched by an organization other than the Load-Serving Entities served by that generation. The depth of the pool progresses as a continuum from no pool to a shallow pool to a deep pool, as the diagram below shows.

No pool. When an organization has "bundled" the Load-Serving Entity, Generator Owner, and Resource Dispatcher functions, then it doesn't operate a pool per se. This could be an example of a vertically integrated utility serving its own customers with its own generation. The Resource Dispatcher would probably dispatch this generation on an incremental cost basis.



Shallow pools. In a shallow pool, the Load-Serving Entities might obtain energy to varying degrees from their own generation, or through bilateral arrangements with Generator Owners and Purchasing-Selling Entities, with the balance of their energy needs supplied by a pool of generation that a Market Operator administers. For example, within the ERCOT ISO, Load-Serving Entities arrange for their energy using bilateral agreements with "qualifying scheduling entities," who, in turn, have bilateral arrangements with Generator Owners. However, while the Generator Owners have a *financial* commitment to provide energy, they may find it more financially advantageous to purchase their energy commitment from the ERCOT "imbalance" energy pool. ERCOT provides the Market Operator function for this imbalance pool, and dispatches pool generation based on bid prices.

Deep pools. In the deepest pool, Load-Serving Entities obtain most of their energy and Ancillary Services from a pool of Generator Owners, some of which may be affiliated with the LSEs and others that are independent, but whose energy is commingled in the pool. The Resource Dispatcher provides the dispatch order for the entire pool of resources that comprises the Resource Dispatch Area based on load forecasts provided by the Load-Serving Entities. This is an arrangement we find in those RTOs and ISOs that provide the Resource Dispatcher function. If the Resource Dispatcher also runs a market by dispatching the pool resources based on bid prices provided by the Generator Owners and Load-Serving Entities, then we refer to the Resource Dispatcher as a Market Operator.

The table below explains further how the Functional Model applies to tasks that are performed by both the vertically integrated utility and the unbundled, market-based pool.

Task	*No Market – Vertically Integrated*	*Market – Unbundled*
Unit Commitment	Utility (performing the Generator Owner function) decides which units to run.	Generator Owners decides which units to make available.
Economic Dispatch	Utility (as Resource Dispatcher) performs economic dispatch calculation based on incremental costs or other requirements. Utility (as the Resource Dispatcher) must consider generator operating limits, which units are providing regulation service, and any commitments for bilateral arrangements.	Market Operator collects bids from Generator Owners and dispatches generators based on market rules (e.g. bids). Market Operator must consider generator operating limits, which units are providing regulation service, and any commitments for bilateral arrangements.
Congestion Management	Results in different incremental costs ("lambdas").	Depending on the market structure, results in 1. Different locational marginal prices (LMP), or 2. Different marginal costs
Regulation Service	Utility (performing the Balancing Authority, Load-Serving Entity, and Generator Owner functions) in concert with the Reliability Authority function, determines the amount of regulation service required and designates those units that can be regulated to maintain ACE. Utility (as the Resource Dispatcher) uses this information in its economic dispatch.	Balancing Authority, along with Reliability Authority, determines amount of regulation service required. Generator Owners decide which units to bid in for regulation service. Market Operator runs bid pool for regulation service. Load-Serving Entity arranges for regulation services.
Generator Control	Utility (performing the Balancing Authority function) pulses units that are designated by Resource Dispatcher for regulation service. As regulating ability declines, Balancing Authority asks Resource Dispatcher for new dispatch.	Balancing Authority pulses units that are designated by Market Operator for regulation service. As regulating ability declines, Balancing Authority asks Market Operator for new dispatch.

4. Providing and Deploying Ancillary and Interconnected Operations Services

Requirement for Ancillary Services. The open access (pro forma) tariff requires the Transmission Provider to *provide* the following Ancillary Services:

1. Scheduling, system control, and dispatch
2. Reactive supply and voltage control from generation

And the tariff requires that the Transmission Provider *offer*:

3. Energy imbalance
4. Regulation and frequency response
5. Operating reserve – spinning
6. Operating reserve – supplemental

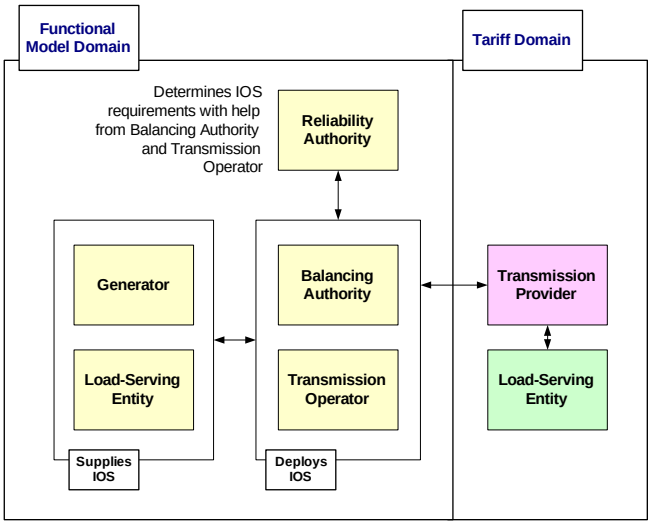


Figure 5 – Supply and deployment of Ancillary Services.

Interconnected Operations Services. NERC defines Interconnected Operations Services as the building blocks of Ancillary Services, and are physically provided by generators and loads[7]. The diagram on the right shows how Ancillary Services in the "tariff domain" are created as Interconnected Operations Services in the "Functional Model domain." The Functional Model explains that the Balancing Authority "Determines [the] amount required and arranges for Interconnected Operations Services to ensure balance in coordination with the Reliability Authority."

- The Balancing Authority determines regulation, load following, frequency response, and contingency reserves, and deploys these as Interconnected Operations Services.
- The Transmission Operator determines reactive power requirements to maintain transmission voltage within operating limits, and deploys these as Interconnected Operations Services.
- The Reliability Authority, working with the Transmission Operator, determines the need for Black Start capacity. The Transmission Operator cannot do this alone, because it may not have a wide enough picture of the transmission system.

[7] Loads can provide reserves through load-shedding or demand-side management. Loads also provide frequency response, depending on the characteristic of the loads.

5. Managing Bilateral Transactions – Basic Concepts

Today, interchange transactions that cross multiple Control Areas are broken down daisy-chain fashion into individual Control Area-to-Control Area schedules, with the sink Control Area designated as the "manager" (the "tag authority"). The Control Area Criteria Task Force thought this arrangement to be clumsy, and knew that occasionally schedules were "lost" along the chain.

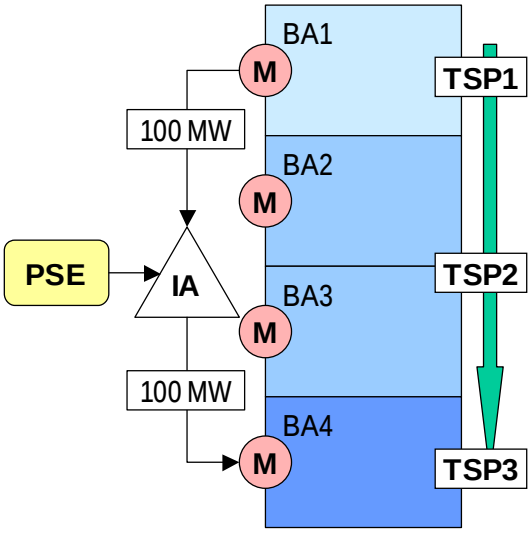


Figure 6 - The Interchange Authority manages transactions between the source and sink Balancing Authorities.

The Functional Model addresses this by including the Interchange Authority as the function responsible for managing Interchange Transactions ("deals") that were ready for physical implementation between Balancing Authorities, and removing the requirement that the source and sink BA's be physically adjacent. Balancing Authorities would then schedule interchange with Interchange Authorities, not other Balancing Authorities, and the IA's would ensure that the schedules were balanced (equal and opposite) between the source and sink BA's. In the example in Figure 6 on the right, the IA manages a transaction from BA1 to BA4. The schedule is

BA1 → IA → BA4

and the transmission service path is

TSP1 →TSP2 → TSP3.

The tables on the following page compare the interchange schedule checkout procedures that the Control Areas use today with the procedures that the Balancing Authorities will use.

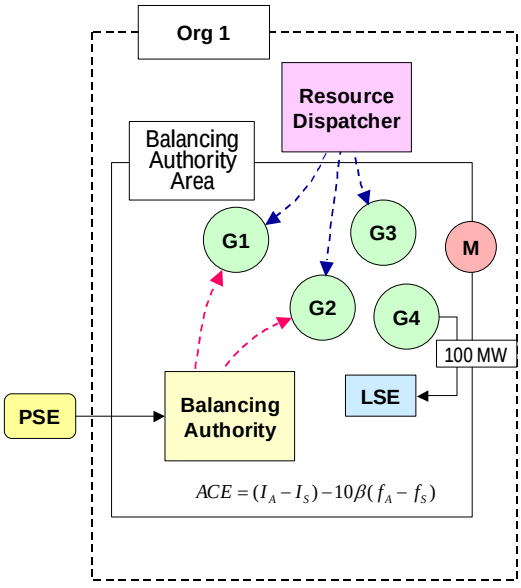
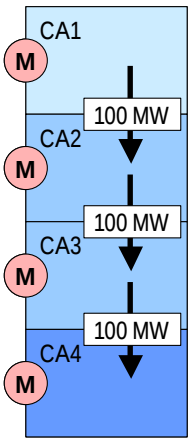
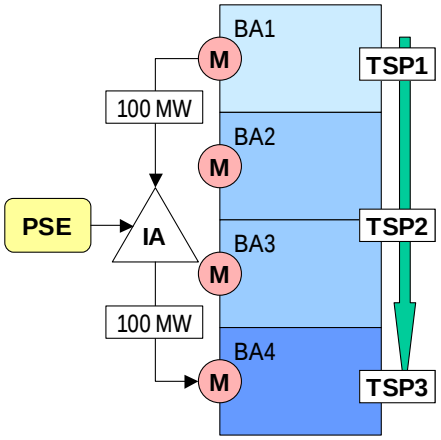


Figure 7 – The Purchasing-Selling Entity submits the bilateral transaction to the Balancing Authority for intra-BA transactions.

Transactions within the Balancing Authority Area. A bilateral transaction within a Balancing Authority does not require Interchange Authority authorization. In the example in Figure 7, the Purchasing-Selling Entity submits the 100 MW transaction to the Balancing Authority who will inform the Resource Dispatcher (or Market Operator) if the Resource Dispatcher needs to know which generators are committed to the transaction, and to the Reliability Authority for reliability assessment.

Checkout under Existing NERC Policies			
Control Area	***Actual from Tie Meters***	***Schedule with CA***	***Inadvertent***
CA1	+100 to CA2	+100 to CA2	0
CA2	-100 from CA1 +100 to CA3	-100 from CA1 +100 to CA3	0
CA3	-100 from CA2 +100 to CA4	-100 from CA2 +100 to CA4	0
CA4	-100 from CA3	-100 from CA3	0
Checkout under the Reliability Model			
Balancing Authority	***Actual from Tie Meters***	***Schedule with IA***	***Inadvertent***
BA1	+100 to BA2	+100 to IA	0
BA2	-100 from BA1 +100 to BA3	0	0
BA3	-100 from BA2 +100 to BA4	0	0
BA4	-100 from BA3	-100 from IA	0





6. Managing Bilateral Transactions – Scheduling Agents

Some Transmission Providers provide a Scheduling Agent service for their Control Area members. The Scheduling Agent provides a single point of contact for all Interchange Schedules into or out of those Control Areas. For example, the Southwest Power Pool serves as a Scheduling Agent for its members, and any Control Area external to SPP will schedule to any SPP Control Area by way of the SPP as the Scheduling Agent. This simplifies interchange scheduling for parties both internal and external to SPP.

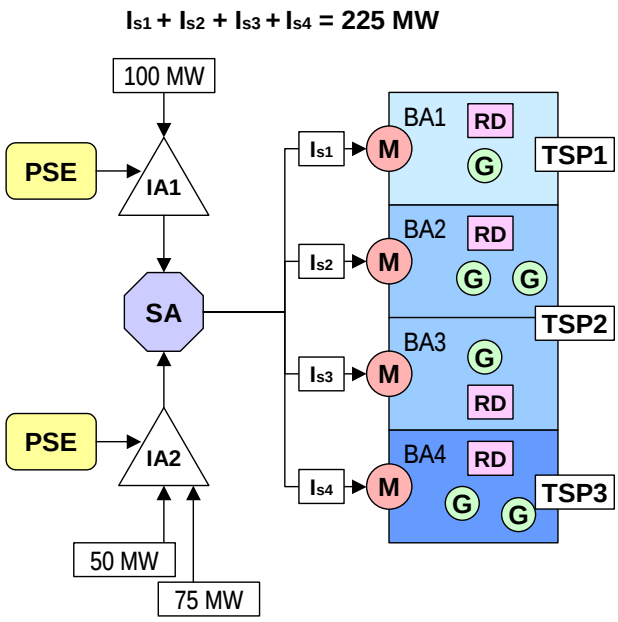


Figure 8 – The Scheduling Agent divides a 100 MW transaction among a group of Balancing Authorities.

In the example in Figure 8, two Interchange Authorities schedule a total of 225 MW with the Scheduling Agent for a group of four Balancing Authorities as follows:

I_{S1} = 100 MW into BA1
I_{S3} = 50 MW into BA3
I_{S4} = 75 MW into BA4
I_{S2} = 0

The Scheduling Agent must ensure that the sum of the Interchange Schedules from all Interchange Authorities is exactly equal to the sum of the Interchange Schedules from the Scheduling Agent to its Balancing Authorities:

$I_{SA1} + I_{SA2} = I_{S1} + I_{S2} + I_{S3} + I_{S4}$

If the Balancing Authority(ies) use a Scheduling Agent, then the Interchange Authority will request ramp confirmation from the Scheduling Agent — not the Balancing Authority(ies) — during the Interchange Transactions authorization process. The Interchange Authority will also notify the Scheduling Agent of any Interchange Transaction curtailments.

Because interchange scheduling is an integral function of the Balancing Authority, the Functional Model Review Task Group believes that the Scheduling Agent is actually an agent of the Balancing Authorities. The Balancing Authorities would still be the *Responsible Entities* for ensuring that the interchange schedules from the Scheduling Agent were incorporated into the BAs' energy management systems. Some have argued that the Scheduling Agent would need to be certified and monitored to ensure that it handled the interchange schedules properly.

For discussion purposes only. The FMRTG believes these scenarios would be difficult to implement.

7. Non-coincident Resource Dispatch and Balancing Authority Areas

Bilaterals between Resource Dispatch Areas. In the examples above, each Balancing Authority Area was the same as the Resource Dispatch Area. When a Resource Dispatcher or Market Operator dispatches generation (either cost-based or bid-based) over several Balancing Authority Areas, we may be faced with a bilateral transaction whose source or sink is the entire Resource Dispatch or Market Area, and can not be identified with any particular Balancing Authority within that area. In this situation, the Interchange Authority schedules with the Scheduling Agent for the Resource Dispatch Area. Then the Scheduling Agent, working with the Resource Dispatcher, will determine how the bilateral transaction is allocated among the Balancing Authority Areas within the organization.

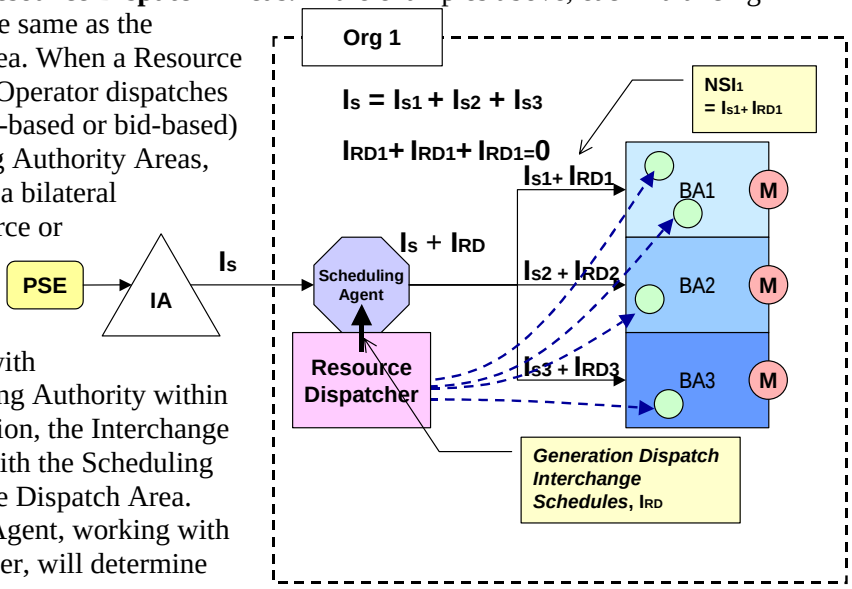


Figure 9 – The Scheduling Agent manages bilateral transactions in to or out of the Resource Dispatch Area as well as the Resource Dispatch Interchange Schedules that result from

As we explained in the technical discussion on Load Following and Regulation, the Scheduling Agent ensures that the RDIS are properly allocated to the Balancing Authorities. Now we can combine the Scheduling Agent's management of RDIS with bilateral transactions as shown in Figure 9.

Bilaterals between Balancing Authorities within the same Resource Dispatch Area. A bilateral transaction between two Balancing Authorities within the same Resource Dispatch Area does not require Interchange Authority management because the Resource Dispatch Area is under a common tariff, and the Resource Dispatcher would have a close relationship with the Reliability Authority. In the example in Figure 10, the Purchasing-Selling Entity has submitted a 100 MW bilateral transaction from BA1 to BA3 directly to the Scheduling Agent who would then coordinate the transaction between the source and sink Balancing Authorities. The Scheduling Agent then submits the

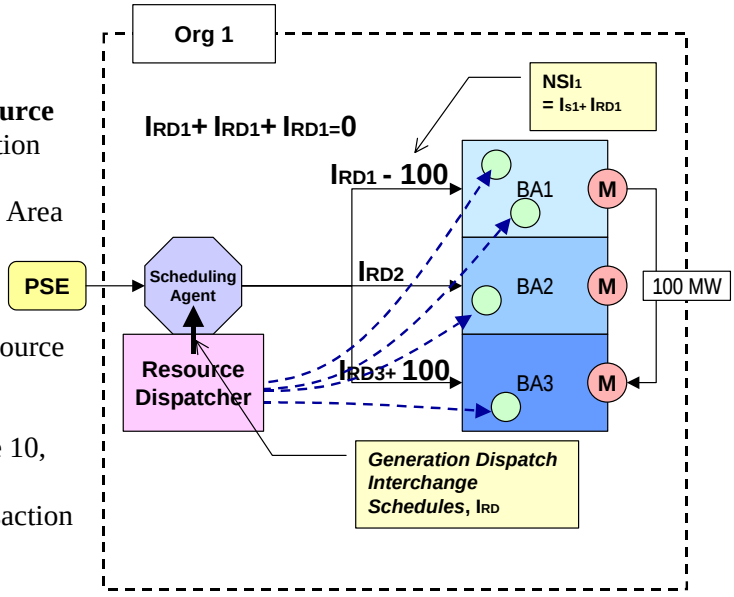


Figure 10 - The PSE submits its transaction information directly to the Scheduling Agent when the bilateral transaction is within the same Resources Dispatch Area.

resulting interchange schedule to the source and sink Balancing Authorities, and inform the Resource Dispatcher if the Resource Dispatcher needs to know which generators are committed to the transaction.

8. Reliability Coordinators

After NERC implemented Version 1 of the Functional Model, some people questioned why the Model did not include the Reliability Coordinator as a function. As the Functional Model Review Task Group was developing Version 2, many suggested that the Reliability Coordinator be included in the Model because they were worried about losing the operational coordination that the RC provides. As this paper explains, the lack of the Reliability Coordinator in the Functional Model should not imply that the RC won't exist. In fact, we expect it to. To help explain this, let's look at the history of the Reliability Coordinator.

The Reliability Coordinator arose from the control area model that still exists. The RC was added in 1996 because NERC was concerned that the 150 control areas would have difficulty coordinating their operations under the open access rules that were emerging. Every Regional Council or Regional Transmission Organization must file a reliability plan with NERC, and that plan must explain how the reliability organization will ensure coordination within its "footprint" and the list of Reliability Coordinators. Each Reliability Coordinator is then audited against NERC's Reliability Coordinator criteria and responsibilities that are included in the Operating Manual.

When the Control Area Criteria Task Force (the FMRTG's predecessor) began developing the Functional Model in 1999, it assumed that the Reliability Authority would perform the role of the Reliability Coordinator. The Task Force picked a different term because the RC was specifically defined in relation to control areas, and not BAs, Transmission Operators, Generators, and so on. Indeed, the tasks that comprise the Reliability Authority function align closely with those of today's Reliability Coordinator, though the Model does not include the degree of detail found in the Reliability Coordinator criteria in the Operating Manual. For example, Version 1 of the Functional Model requires that the Reliability Authority calculate Operating Security Limits (OSL), which means the RA must have a very wide view of the interconnection and the ability to conduct contingency analyses over that area. Version 2 of the Model replaces "OSL" with "Interconnection Reliability Operating Limits" that's now referenced in draft Standard 200, but they mean the same thing.

But we need to look further than the Functional Model to fully develop the functionality of the Reliability Authority, its scope of coverage, and the criteria and standards that the RA must follow. Properly crafted, the following documents will tailor the requirements of the RA to meet the needs of the industry that the RC provides today:

1. **Regional Reliability Plan**. As they are today, the Regions (or Regional Entities within an SRO structure) will be responsible for developing a plan that specifies how reliability will be maintained within that Region, and that plan must include provisions for reliability coordination. The reliability plan will specify who the Reliability Authorities will be, and how they will provide the coordination among the Balancing Authorities, Transmission Operators, Generator Operators, and others. The NERC Operating Committee will continue to review and approve those plans. If the Region wants to call their designated Reliability Authorities "Reliability Coordinators," that's just fine. But NERC will certify them as Reliability Authorities.

2. **Certification requirements**. Based on the Regional plan, the designated RA(s) will be certified against a list of criteria that are developed through the Standards Development

Process. Those criteria should require the RA to have the "big picture" and be able to calculate Interconnection Reliability Operating Limits. Those criteria should also require the RA to have the authority to direct actions necessary to mitigate IROLs as well as other emergencies.

3. **Reliability Standards**. Standard 200, which is still in draft form, requires the RA to determine Interconnection Reliability Operating Limits (the new term replacing OSL). This determination requires a wide view of the transmission system.

In summary, the Functional Model alone is not designed to provide all the relationships and criteria that are needed to ensure a reliable system. The regional reliability plans, the certification requirements, and the standards all play an important role. If the industry wants the Reliability Authority to have the attributes of today's Reliability Coordinator, then the industry will need to write the RA certification criteria accordingly and the regional reliability plans will need to accommodate those criteria.

9. Task Assignment Options

Delegation

An organization, such as an RTO, can delegate tasks to one or more organizations. In this example (Figure 11), the organization is the NERC-certified Transmission Operator, but has delegated some of the Transmission Operator tasks to its members. In this situation, NERC would expect that the organization would be the Responsible Entity, and that its members are carrying out certain tasks under that organization's direction.

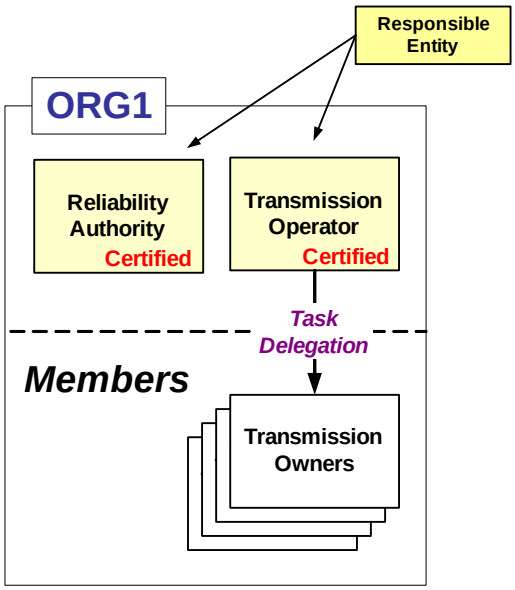


Figure 11 - In this example, Organization 1 has delegated certain Transmission

Organization Pact

In this example, the two organizations have assumed the tasks that must be performed by the Balancing Authority. One of these organizations (in this case, Organization 2) registers with NERC that it is the Designated Responsible Party, and is responsible for compliance requirements and penalties. It would have an agreement with Organization 1 on how penalties would be assigned between these two organizations.

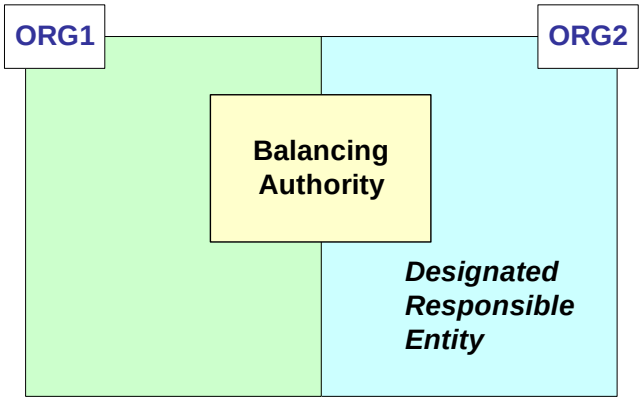
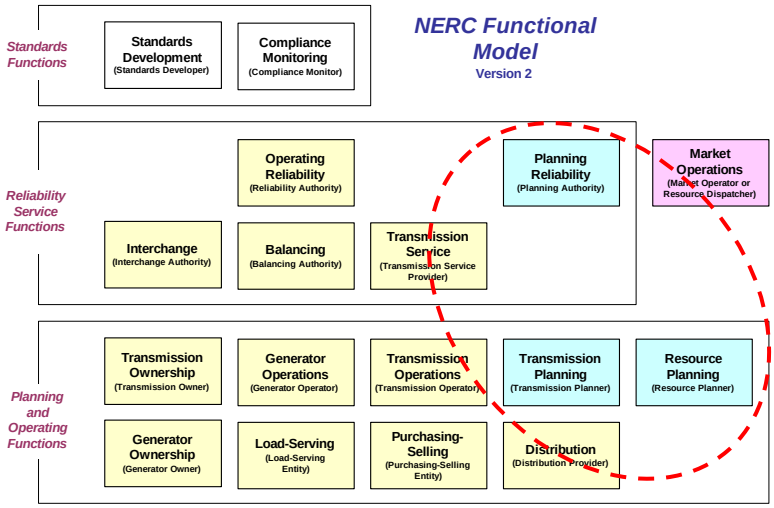


Figure 12 - An organization "pact" allows the Balancing Authority's tasks to be shared, but one of the organizations must register with NERC as the Balancing Authority ("responsible entity) for that function.

The certification audit team may have to visit both organizations.

10. Planning Functions

During the past year and a half, the NERC Planning Committee and its Planning Reliability Model Task Force (PRMTF) have been working to expand the NERC Functional Model to include the planning functions. The Operating Committee's Control Area Criteria Task Force had previously developed the operational portion of the Functional Model (Version 1), which was approved by the NERC Board of Trustees in June 2001. Adding the planning functions completes the NERC Functional Model, and allows it to serve as the framework for the Reliability Standards that cover resource planning and transmission planning.



The PRMTF and Functional Model Review Task Group (FMRTG) propose adding three planning functions to the model: Planning Reliability function, Transmission Planning function, and Resource Planning function. The Planning Authority, who is the responsible entity for the Planning Reliability function, resides at the "highest" planning level, with the Transmission Planners and Resource Planners within their respective Planning Authority Area reporting to the Planning Authority.

Planning Reliability Function

The Planning Authority, who is responsible for the Planning Reliability function, ensures that a long-term (generally 1 year and beyond) plan is available for adequate resources and transmission within its Planning Authority Area. It integrates and assesses the plans from the Transmission Planners and Resource Planners within its Planning Authority Area to ensure that their plans comply with reliability standards. It also develops and recommends solutions to plans that do not meet reliability standards. The Planning Authority is not responsible for implementing the transmission and resource plans. However, it helps to ensure that adequate resources and transmission facilities are placed into service in a timely manner through the Resource Planners, Transmission Planners, and possibly others through open solicitations for facilities.

Like the Resource Planners and Transmission Planners at the "local" level, the Planning Authority maintains system models and performs the necessary studies to evaluate whether the composite resource and transmission plans of its Resource Planners and Transmission Planners are in compliance with reliability standards.

Calculates operating and transfer limits. The Planning Authority reviews the transmission transfer capability determinations of the Transmission Planners and also determines future (generally 1 year and beyond) transfer capabilities and operating limits

between and among the Transmission Planners and other Planning Authorities based on the transmission and resource plans. These longer-term transfer and operating limits are provided to the Reliability Authority and Transmission Operator(s) for their use in developing shorter-term (generally less than one year) operating limits.

Evaluates plans for customer requests. The Planning Authority evaluates responses for long-term (generally 1 year and beyond) transmission service requests developed by its Transmission Planners and provides the resulting plans to the Transmission Service Providers, Transmission Owners, and Transmission Customers. The Planning Authority also reports on industry trends for customer demand, transmission expansion, and resources within its Planning Authority Area. It also provides, as appropriate, plan assessments and reports to regulatory authorities and government agencies, and tracks capacity, demand programs, and transmission in-service dates. Finally, the Planning Authority evaluates the impact of revised generation and transmission in-service dates on the long-term reliability of the bulk transmission systems.

Resource Planning Function

The Resource Planners, who are the responsible entities for the Resource Planning function, develop long-term (generally 1 year and beyond) resource adequacy plans necessary to supply specific customer demands within the Planning Authority Area. These plans can also be provided by the Load-Serving Entities or Generator Owners, or both, within the Planning Authority Area.

Develops resource plans. The Resource Planners maintain resource models to develop and evaluate resource plans in conjunction with reliability standards. These models also are coordinated with the Resource Planner's related Planning Authority. The Resource Planners also identify areas of resource deficiency and provide potential alternative solutions to meet resource requirements.

The Resource Planners also evaluate, in conjunction with the Transmission Planners and Transmission Owners, the deliverability of the planned resources to the customer demands.

Provides resource plan to Planning Authority. The Resource Planners provide their resource plans to the Planning Authority for assessment and review for compliance with reliability standards. They also track capacity and demand program in-service dates, and evaluate the impact of revised generation and transmission in-service dates on resource adequacy.

Transmission Planning Function

The Transmission Planners, who are the responsible entities for the Transmission Planning function, provide long-term (generally 1 year and beyond) transmission plans for the areas under their purview, called the Transmission Planning Areas. A Transmission Planning Area may be smaller than or equal to the Area of its related Planning Authority. Every existing and proposed transmission line, or portion thereof, must be within the boundary of a Transmission Planning Area.

The Transmission Planners coordinate with other Transmission Planners to include the impacts of transmission plans on both on an intra- and inter-area basis. The Transmission Planners also maintain the system models and perform the necessary steady-state,

dynamic, and short-circuit studies to ensure that their transmission plans meet reliability standards. These models are also coordinated with the Transmission Planner's related Planning Authority.

Evaluates customer requests for transmission service. The Transmission Planner evaluates long-term (typically longer than one year) requests for transmission service (as compared to the Transmission Service Provider who evaluates and provides transmission service for the shorter term (generally less than one year)), and identifies the facilities that will be needed to integrate new generation, transmission, and end-use customers into the bulk electric systems. Requests for transmission service will usually come from Transmission Owners, Generator Owners, Load-Serving Entities, and Transmission Service Providers.

Develops planning procedures and protocols. The Transmission Planners develop the planning procedures and protocols that are necessary to ensure that a reliable transmission system is developed within their respective Transmission Planning Areas. These procedures and protocols include specifications for transmission data, system protection and control and special protection systems as needed, and voltage and stability limits to meet reliability standards. They also coordinate these procedures and protocols with neighboring Transmission Planners and their related Planning Authority.

Develops transmission expansion plans. Based on customer requests for transmission service, the planning procedures and protocols established for their Transmission Planning Areas, plus the reliability standards, the Transmission Planners will develop transmission plans to accommodate long-term firm transmission service requests. While developing these plans, they may provide alternate solutions and evaluate alternatives suggested by the transmission customers.

Provides transmission plan to Planning Authority. The Transmission Planners provide their transmission plans for their respective Transmission Planning Areas to their Planning Authority for assessment and review for compliance with reliability standards.

11. Electrical and Physical Boundaries

Boundaries for Operations

Today, NERC requires that every generator, load (customer), and transmission facility be within the metered boundary of a control area. This ensures that the control area:

1. Balances all resources with demand, including transmission system losses, and

2. Operates all transmission facilities within their operating limits.

The Functional Model groups the control area tasks into functions, but we must still ensure that all generation, load, and transmission facilities be physically located within certain boundaries to ensure generation-load balance and reliable transmission operations. However, under the Functional Model, we need to consider these boundary conditions from the Reliability Authority's and Balancing Authority's points of view. NERC will need to incorporate these boundary conditions into its Reliability Standards.

Boundary Conditions for Transmission Reliability

The boundary conditions for transmission reliability deal with where generators, transmission facilities, and customers are *physically* located.

- The Reliability Area must include all transmission facilities within the Area's metered boundaries, and all load and generation physically connected to those transmission facilities.
    - The transmission facilities within the Reliability Area are defined as those within the transmission metered boundaries of the Balancing Authority Areas under the RA's purview.
    - The Reliability Area will therefore include all load and generation physically connected to those transmission facilities.

Boundary Conditions for Balancing

The boundary conditions for balancing deal with where generators and customers are both *physically and electrically* located. This recognizes that a generator or load may use a "pseudo" tie to virtually move itself out of one Balancing Area and into another.

- Every generator must be metered into a Balancing Authority Area.
- Every load (customer) must be metered into a Balancing Authority Area.
- Every transmission facility must be within the metered boundary of a Balancing Authority Area.
- Every Balancing Authority must designate a Reliability Authority.

Discussion

Considered together, these boundary conditions mean that:

- A Reliability Area is defined by the metered boundaries of the Balancing Authority Areas under its purview.

- A generator or customer falls within the purview of the Reliability Area in which that generator or customer is *physically* located.

- The Regional Reliability Plan will specify those organizations that will serve as the Reliability Authorities and Balancing Authorities within the Regional Council.

Boundaries for Planning

The Planning Reliability functions and the associated Transmission Planning functions and Resource Planning functions apply to specific defined areas that may or may not have a direct correlation with the operating reliability areas defined as a Reliability Authority Area or a Balancing Authority Area. The planning areas and their boundary relationships with other areas are defined below.

Planning Authority Area

The Planning Reliability functional tasks that must be performed by a Planning Authority include an integration and assessment of the resource and transmission plans of others to ensure that an adequate long-term (generally 1 year and beyond) resources and transmission plan is available for an area called the Planning Authority Area. The Planning Authority Area is a defined area for which the Planning Authority has responsibility and includes the generators, transmission facilities, and customer demands in that area.

Each Planning Authority Area is a unique area and cannot overlap other Planning Authority Areas. The Planning Authority Area also may be smaller than, equal to, or larger than a Reliability Authority Area or a Regional Reliability Council.

Transmission Planning Area

The Transmission Planning Area is a defined area within a specific Planning Authority Area. The Transmission Planning Area is the designated Area for which a Transmission Planner has the responsibility for developing a long-term (generally 1 year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric systems within its portion of the Planning Authority Area. The Transmission Planning Area may be an area smaller than or equal to its related Planning Authority Area.

Existing and proposed transmission lines, or portions thereof, must be within the boundary of a Transmission Planning Area. The Transmission Planners must agree on how transmission between Transmission Planning Areas will be addressed.

A given Transmission Planning Area may encompass an area smaller than, equal to, or larger than its related Reliability Authority Area.

Resource Planning

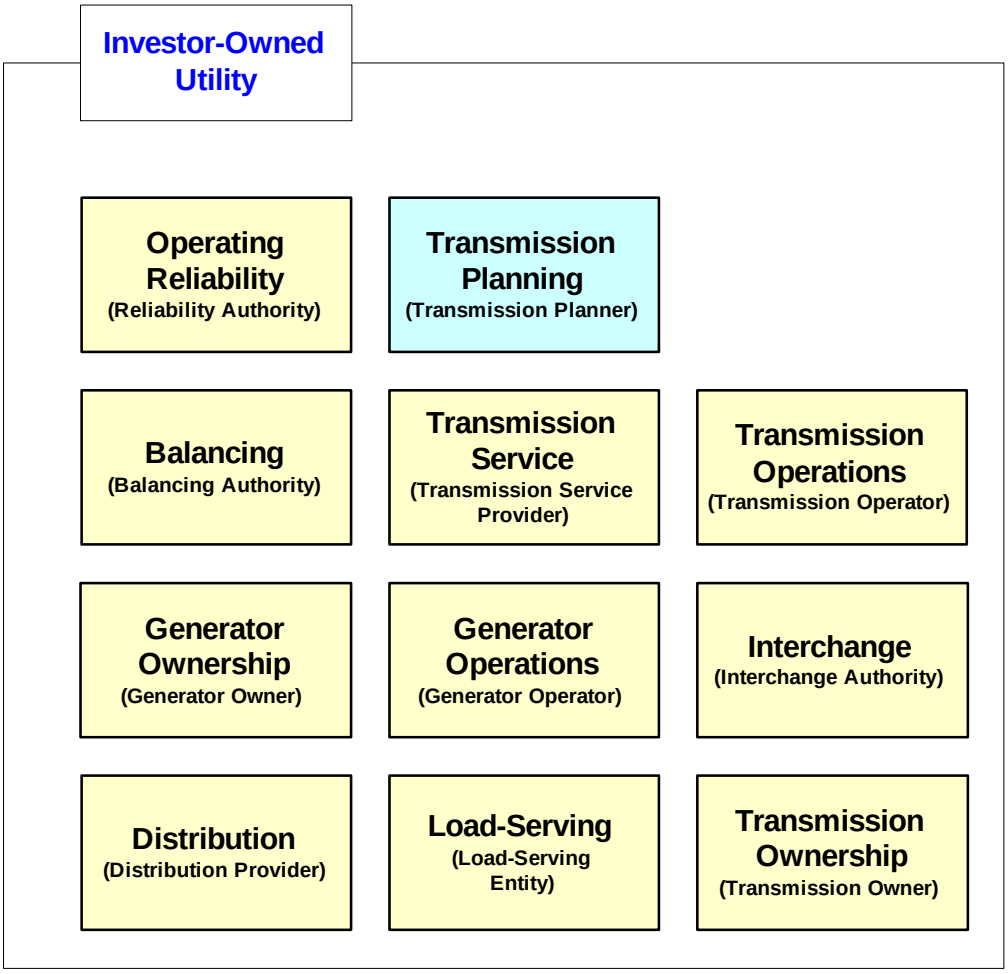
The boundaries for the Resource Planning function are difficult to define as a Resource Planner developing a long-term (generally 1year and beyond) resource adequacy plan for specific loads (customer demand and energy requirements) within a Planning Authority

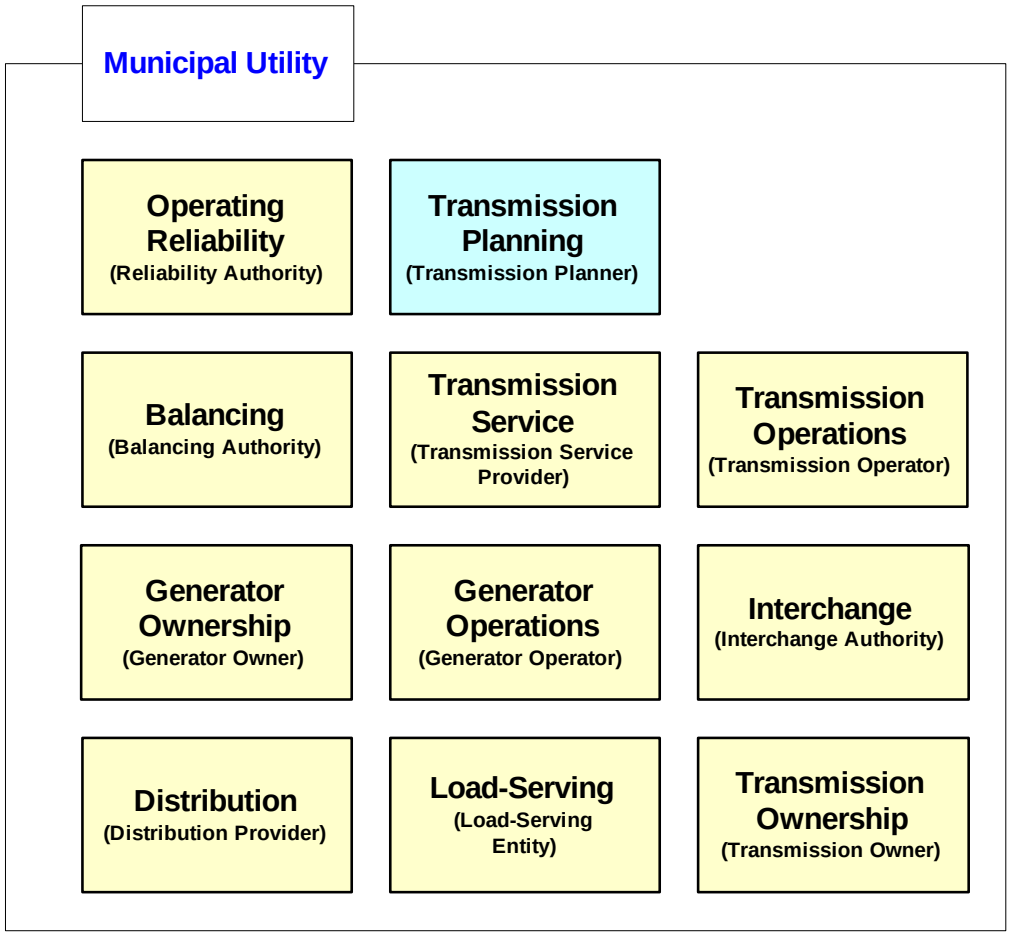
Area may consider generation capacity both within and outside of the Planning Authority Area.

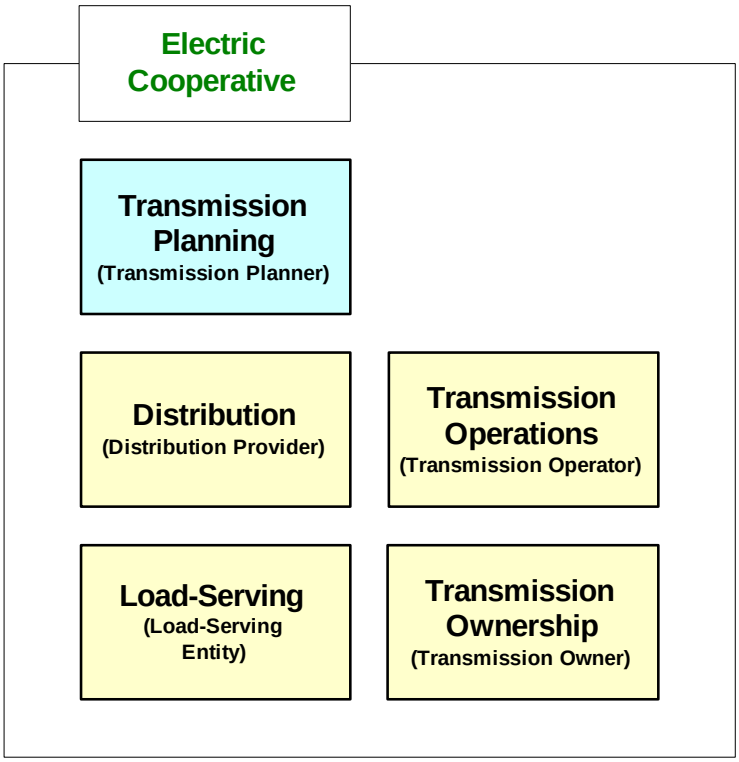
The loads addressed by a Resource Planner may encompass customer demands smaller than or equal to its related Planning Authority Area, but these customer demands must be within the Planning Authority Area. It may take one or more Resource Planners to cover all of the customer demands within a given Planning Authority Area.

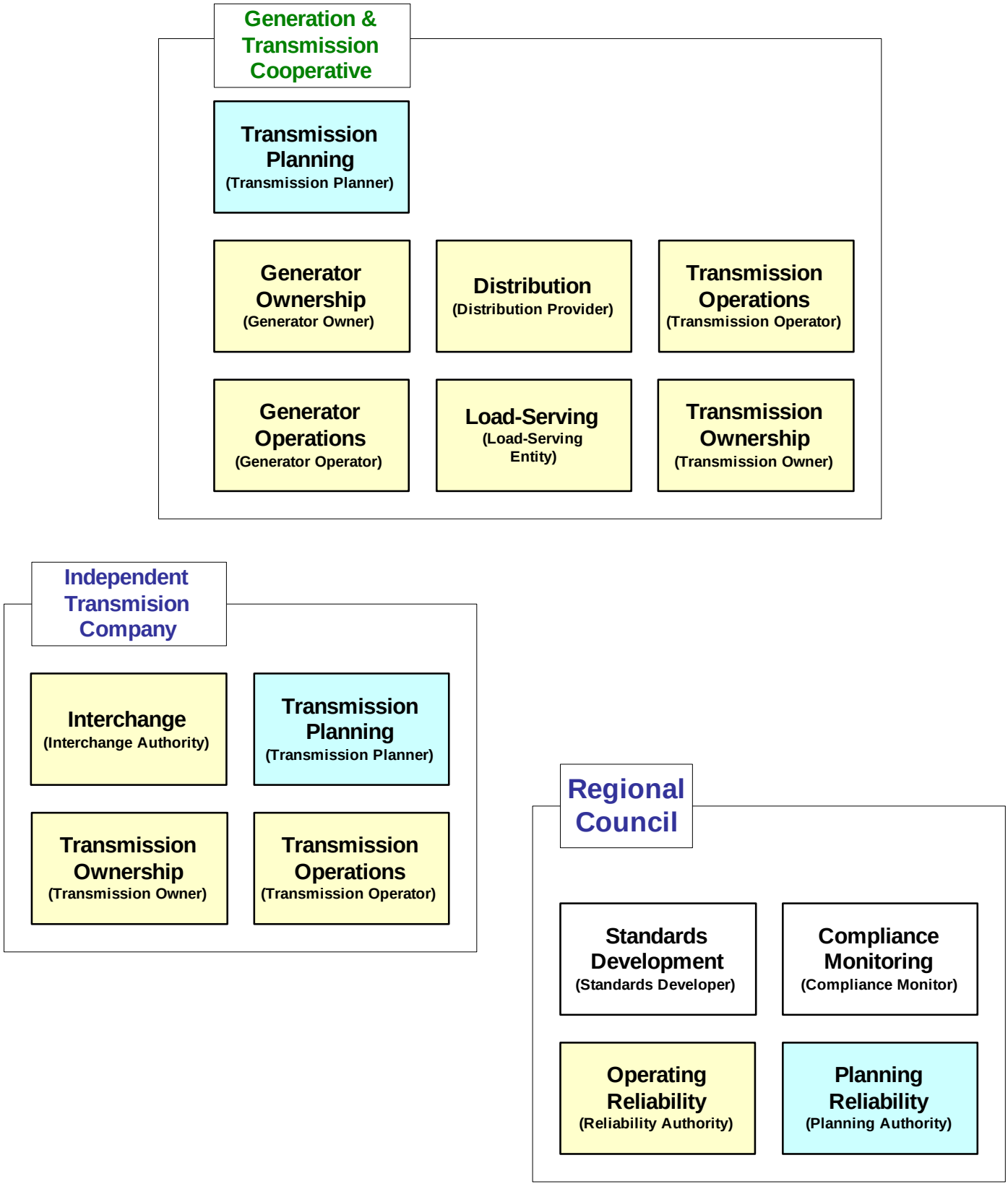
12. Rollup Examples

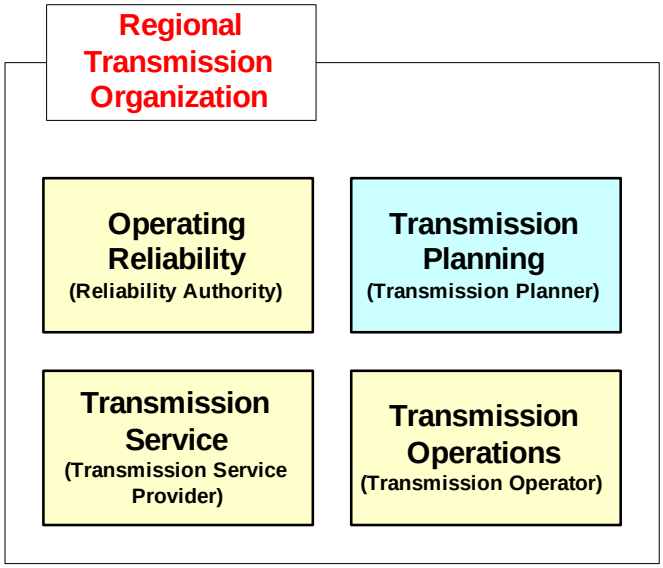
Organizations will "roll up" the *Functions* they intend to perform and register with NERC as *Responsible Entities*. This section includes a number of examples to show how this would work.




Municipal Utility
Operating Reliability
(Reliability Authority)
Transmission Planning
(Transmission Planner)
Balancing
(Balancing Authority)
Transmission Service
(Transmission Service Provider)
Transmission Operations
(Transmission Operator)
Generator Ownership
(Generator Owner)
Generator Operations
(Generator Operator)
Interchange
(Interchange Authority)
Distribution
(Distribution Provider)
Load-Serving
(Load-Serving Entity)
Transmission Ownership
(Transmission Owner)


Electric Cooperative
Transmission Planning
(Transmission Planner)
Distribution
(Distribution Provider)
Transmission Operations
(Transmission Operator)
Load-Serving
(Load-Serving Entity)
Transmission Ownership
(Transmission Owner)


Generation & Transmission Cooperative
Transmission Planning
(Transmission Planner)
Generator Ownership
(Generator Owner)
Distribution
(Distribution Provider)
Transmission Operations
(Transmission Operator)
Generator Operations
(Generator Operator)
Load-Serving
(Load-Serving Entity)
Transmission Ownership
(Transmission Owner)
Independent Transmision Company
Interchange
(Interchange Authority)
Transmission Planning
(Transmission Planner)
Transmission Ownership
(Transmission Owner)
Transmission Operations
(Transmission Operator)
Regional Council
Standards Development
(Standards Developer)
Compliance Monitoring
(Compliance Monitor)
Operating Reliability
(Reliability Authority)
Planning Reliability
(Planning Authority)


Regional Transmission Organization
Operating Reliability
(Reliability Authority)
Transmission Planning
(Transmission Planner)
Transmission Service
(Transmission Service Provider)
Transmission Operations
(Transmission Operator)

Functional Model Review Task Group and Planning Reliability Model Task Force

Members and active participants

James A. Byrd – Oncor - Functional Model Review Task Group Chairman

Michael C. Raezer – Tucson Electric Power Company - Planning Reliability Model Task Force Chairman

Donald E. Badley – Northwest Power Pool

Gerald W. Burrows – Kansas City Power & Light Company – Organization Certification Task Force Chairman

Ken Clark – Exelon Power Team

James D. Cyrulewski – Michigan Electric Power Coordination Center

Albert M. DiCaprio – PJM Interconnection, L.L.C.

Mark Fidrych – Western Area Power Administration – NERC Operating Committee Vice Chairman

R. S. (Scott) Henry – Duke Power Company – Interconnected Operations Services Subcommittee Chairman

Andrew J. Rodriquez – Oxygen Consulting, L.L.C.

Amir Shalaby and Mike Yealland – The IMO

Anthony Jankowski – WE Energies - Market Interface Practices Subcommittee Chairman

Roman Carter – Southern Company

John F. Stough – AEP Service Corporation (Transmission System)

Karl Tammar – New York Independent System Operator – Electronic Scheduling Collaborative Member

Peter Harris – ISO New England

Mike Risen – Basin Electric Power Cooperative

Kenneth Haase – New York Power Authority

Douglas Collins – Alliant Energy

Susan Morris

Stanley Kopman – Northeast Power Coordinating Council

Gregory Vincent – Tennessee Valley Authority

Ken Kuyper – Corn Belt Power Cooperative

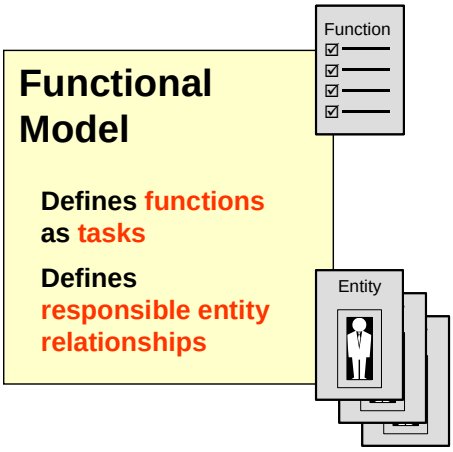
Virginia Sulzberger – NERC Staff - Planning Committee and Planning Reliability Model Task Force Facilitator

William Lohrman – NERC Staff - Market Interface Committee Facilitator

John R. Twitchell – NERC Staff

Donald M. Benjamin – NERC Staff – Functional Model Review Task Group Facilitator

Item 4. Functional Model Concepts



Action

Discussion to understand the purpose and guiding principles of the Functional Model.

Background

Before the working group begins working on the recommendations, we need to have a clear understanding of the purpose and guiding principles of the Functional Model. The standing committee officers wrote the purpose statement as part of the development of Version 2 of the model to clearly explain the importance of the Functional Model and the role it plays in NERC's standards development process. The Functional Model Review Task Group wrote the guiding principles with the intent that subsequent groups would follow those principles when revising or interpreting the Functional Model so as to maintain the integrity of the model and NERC's reliability standards.

Purpose of the Functional Model

The purpose of the NERC Reliability Functional Model is to:

1. Functionalize the tasks being performed today for electric system reliability so that reliability organizations such as control areas, regional transmission organizations, independent system operators and others can more easily and clearly identify the reliability functions they provide. A specific organization may provide one or more of the functions identified in the Functional Model.
2. Define in general terms each function and the relationships between the entities that are responsible for performing the tasks within the functions. The framework for developing the function definitions is:
    a. The responsibility for performing a function should not be split by organizations
    b. The functions are independent of the organization structure performing the function, and
    c. The function definitions provide flexibility to accommodate the range of presently conceivable organization structures.
3. Provide a framework for reliability standards (including organization certification criteria) and compliance measures developed through the NERC Standards Development Process that will apply to certain tasks defined in the Functional Model.
    a. It is not expected that standards will be developed for each task since the Functional Model is developed in more detail than is needed for reliability standards. However, standards may contain more detail than the associated activity in the Functional Model.

b. Responsibility for compliance with a standard will apply to the organizations performing that function.

c. Other organizations developing standards may use the NERC Functional Model in the same manner.

4. Provide linkages between business practices developed by other organizations showing how certain practices may relate to the reliability functions in the Functional Model.

Guiding Principles

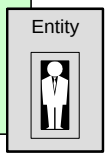
As explained in the "Purpose of the Functional Model," the Functional Model provides the framework on which the NERC reliability standards are based. To ensure that this framework remains viable, the model itself is governed by a set of "guiding principles" that define a *function*, and establish the relationship between the *responsible entities* that are responsible for performing the *tasks* listed in the model, and the NERC *reliability standards*. NERC must work within these guiding principles when revising or interpreting the Functional Model to maintain the integrity of the model and NERC's reliability standards.

1. The Functional Model defines the *functions* that must be performed and does not imply organization structure or hierarchy.
    a. Functions comprise *tasks*.
    b. Tasks are *what* must be done, not *how*.
2. An *organization* that registers with NERC as performing a function is considered a *responsible entity* and must ensure that all tasks are performed.
    a. Reliability standards are those requirements that must be performed by *responsible entities*. Thus, we say that the Functional Model is the framework on which the reliability standards are based.
    b. An organization may delegate a task to another organization, but may not delegate its responsibility for ensuring that the task is accomplished.
3. Organizations that perform certain functions must be certified as being capable of performing those functions. Organization certification requirements are a category of NERC standards
4. Some tasks in the Functional Model may not result in a reliability standard.

Item 5. Regional Reliability Plans

Regional Reliability Plans

Designates which organizations are Reliability Authorities and Balancing Authorities



Action

Discussion to review the concept of the regional reliability plans.

Attachments

- Template for Developing a NERC Regional Operating Reliability Plan
- Template for Developing a Reliability Coordinator Reliability Plan
- Template for Developing a Balancing Authority Integrated Operational Plan

Background

The genesis for the regional reliability plans was the 1996 report of the Security Process Task Force.

Recommendation #4 — Regional Security Plans

Each Region must develop a security plan to meet NERC Policies, Standards, and Requirements that deal with operational security. This plan must include:

1. **Implementation of Security Coordinator** to ensure intra- and interregional coordination of emergency procedures.
2. **Explanation of how operational security information will be made available** to all control areas and Security Coordinators via the Interregional Security Network.
3. **Description of emergency operating procedures**, including procedures for dealing with line load relief, and the role of the Security Coordinator in coordinating these procedures, both intra- and interregionally. These procedures must:
    i. Be coordinated throughout each Region and across Regional and subregional boundaries,
    ii. Include the responsibilities and authorities for ensuring they are carried out, and
    iii. Be implemented in a fair and non-discriminatory manner.
4. **Description of the types of operating problems** that have occurred or are reasonably expected in the Region and
    i. How its security processes will reduce the Region's vulnerability of these problems,

ii. How the Region's emergency operating procedures will mitigate these problems, and

iii. How the Region performs "look-ahead" operational assessments.

5. **Explanation of how the Region will deal with the security aspects of parallel flows** to ensure that transmission transfer capabilities are not exceeded.

The regional reliability councils — and later the RTOs — have filed their regional reliability plans with NERC, and updated those plans as the Reliability Coordinator "footprints" change or as they adopt new structures and protocols.

But NERC ran into two problems: First, when NERC began to audit the Reliability Coordinators a few years ago, it found that the Regions interpreted the requirements of the Reliability Plans differently. Some Regions required their Reliability Coordinators to directly perform the tasks that were required under (then) Policy 9, "Reliability Coordinator Procedures." But other Regions allowed their Reliability Coordinators to delegate almost all of their tasks to their member control areas. The regional plan requirements didn't specify this level of detail.

Second, NERC did not establish guidelines or specifications by which the feasibility of the Regional Plans could be judged. Could any entity become a Reliability Coordinator? Did every control area have to designate a Reliability Coordinator? Suppose a regional reliability council wanted to have 15 Reliability Coordinators. Was that OK?

The Operating Committee then decided to rewrite the requirements for the regional reliability plans to address these concerns and shortcomings. But that project didn't last long because NERC was also rewriting its reliability standards around the Functional Model, and the Reliability Coordinator was replaced by the Reliability Authority.

The Operating Committee then formed a Reliability Coordinator Plan Task Force to rewrite the regional reliability plan guidelines, or "templates." These new templates would be much more comprehensive than the guides that were in the SPTF final report, and would use the NERC standards as their basis. And they would require that the Regional Councils specify the Reliability Coordinators (or Reliability Authorities) as well as the Balancing Authorities to ensure there were no gaps or overlaps.

The Functional Model-Reliability Standards Coordination Task Force recommended that the regional plans also include transmission authorities, interconnection reliability authorities, interconnection planning coordinators, transmission planners, resource planners, and transmission owners.

We've attached the latest drafts of the Regional Plan, Reliability Authority, and Balancing Authority plan "templates" along with the comments we received when they were posted.

Template for Developing a NERC Regional Operating Reliability Plan

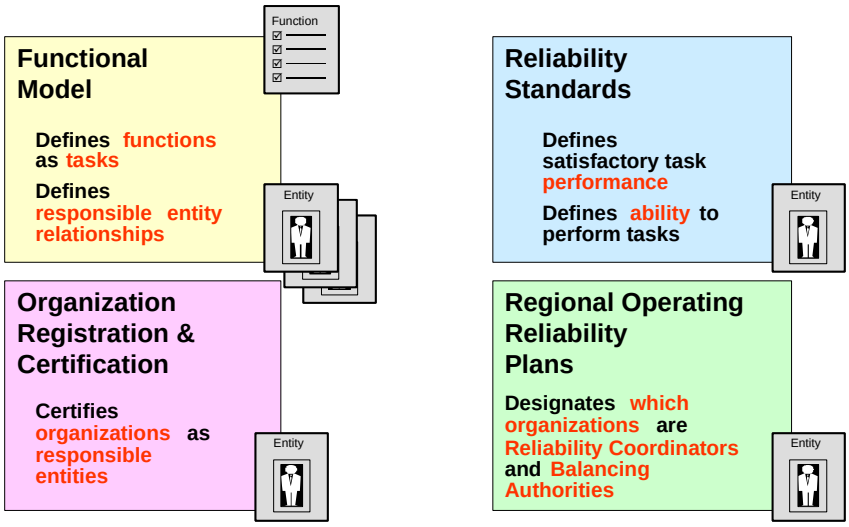
Draft 5

Introduction

The NERC Template for Developing a Regional Operating Reliability Plan provides the detailed requirements for ensuring adequate reliability oversight and coordination. Each Regional Council is expected to submit a Regional Operating Reliability Plan to the NERC Operating Committee for review and approval, and must review and keep its Regional Operating Reliability Plan up to date as required by NERC.

The NERC Regional Operating Reliability Plans complement the NERC Reliability Functional Model and NERC Version 0 Reliability Standards. The Reliability Functional Model provides the foundation and framework upon which NERC develops and maintains its Reliability Standards. The Regional Operating Reliability Plan requirements focus on specific responsible entities to which the Reliability Standards are written. Those entities are the Reliability Coordinator[1] and the Balancing Authority.

The figure on the right explains the relationship among the Regional Operating Reliability Plan, the Reliability Functional Model, the Certification requirements, and the Reliability Standards.



Background – The Reliability Coordinator and the Balancing Authority

From "NERC Reliability Functional Model Technical Document," dated October 31, 2003 and NERC Version 0 Reliability Standard.

Reliability Coordinator

The Reliability Coordinator is the highest-level authority and can direct all operational reliability functions within its Reliability Coordinator Area. The Reliability Coordinator is responsible for the reliable operation of its Reliability Coordinator Area within the Bulk Electric System in accordance with NERC, Regional and sub-Regional standards and practices. The Reliability Coordinator determines Interconnected Reliability Operating Limits based upon Transmission and Generation Owners' specified equipment ratings, system operating limits calculated by the Transmission Operator(s), plus system studies. The Reliability Coordinator monitors its Reliability Coordinator Area to ensure the system operates within its thermal, voltage, and stability limits. The Reliability Coordinator monitors and ensures transmission system reliability at all times. It also specifies the requirements for Interconnected Operations Services to ensure transmission reliability.

[1] The Functional Model defines the Reliability Authority rather than today's Reliability Coordinator. However, until the various authorities and protocols of the Reliability Authority are sorted out, the initial set of reliability standards ("Version 0") includes the Reliability Coordinator, as it exists today.

The Reliability Coordinator's purview must be broad enough to enable it to calculate Interconnection Reliability Operating Limits, which may be based on the operating parameters of other transmission systems beyond the Transmission Operator's vision. The Transmission Operator is responsible for the reliability of its "local" transmission system, and may not be aware that its system is violating an Interconnection Reliability Operating Limit. Therefore, the Reliability Coordinator shall have the authority to direct the Transmission Operators or Balancing Authorities within its Reliability Coordinator Area to take action to mitigate System Operating Limits and Interconnected Reliability Operating Limits.

The Reliability Coordinator also assists the Transmission Operator in relieving equipment or facility overloads through transmission loading relief measures if market-based dispatch procedures are not effective.

Balancing Authority

The Balancing Authority operates within the metered boundaries that establish the Balancing Authority Area. Every generator, transmission facility, and end-use customer must be in a Balancing Authority Area. The Balancing Authority's mission is to maintain the balance between loads and resources in real time within its Balancing Authority Area by keeping its actual interchange equal to its scheduled interchange and providing its frequency bias obligation.

Comments

Gilbert Jakubowski BGE	Would like to see some reference made on the "Check and Balance approach" in correcting for violations. Where the Reliability Coordinator and the Transmission System Operator compare their respective Real Time Security Analysis results and the most severe Violation is the one corrective action is taken for. That is for Violations that are seen by both the Reliability Coordinator and the Transmission Operator.
Roman Carter Marc Butts Southern	Southern Co. Generation questions whether this Plan is needed? The concepts contained within this Plan can be found in the Version 0 Standards. If this document is retained for whatever reason, there is a need for the reporting relationship between the Reliability Coordinator (RC) and the Reliability Authority (RA) to be explained. For instance, the Reliability Coordinator having the highest-level authority can direct all RAs within its operational area to take action to mitigate System Operating Limits (SOL) and Interconnnected Reliability Operating Limits (IROL). The RAs within an RC area would be responsible for local security from real-time to 13 months out into the future. Finally, this guide for Developing a NERC Regional Operating Reliability Plan should not be confused with Planning Templates or Compliance Templates and therefore should be referred to as a "Guide or Reference Document" to make a clear distinction between the NERC Templates and this Guide.
Edward J. Davis Entergy	1. Please change the first two sentences in Reliability Coordinator from "The Reliability Coordinator is the highest level authority and can direct all operational reliability functions within its Reliability Coordinator Area. The Reliability Coordinator is responsible for the reliable operation of its Reliability Coordinator Area…"to" The Reliability Coordinator is responsible for monitoring and ensuring the reliable operation of the transmission system within its Reliability Coordinator Area … ". 2. It is difficult to determine from the above what constitutes the Regional Operating Reliability Plan. We suggest that after the Balancing Authority section

	the following new section be added: "A. Regional Operating Reliability Plan Each Regional Council shall develop a Regional Operating Reliability Plan made up of: 1) A Reliability Coordinator Reliability Plan for each Reliability Coordinator within the Region, and 2) A process for ensuring that every generator, transmission facilities, and all retail customers are within the boundaries of a Balancing Authority, and 3) That each Balancing Authority has an endorsed Integrated Operational Plan."
Alan Boesch NPPC	Transmission Operators also play an important part in maintaining the reliability of the bulk electric system.

Regional Operating Reliability Plan Requirements — Reliability Coordinators

1. **Designation of Reliability Coordinators**. The Regional Council shall provide the Operating Committee with a list of the Reliability Coordinators within the Regional Council's boundary and provide updates whenever that list changes.

    1.1. **Balancing Authorities**. The Reliability Coordinator list shall include a list of all Balancing Authorities under the purview of each Reliability Coordinator. The list shall also include all anticipated changes and the dates of those changes.

2. **Reliability Coordinator Reliability Plan.** The Regional Council shall ensure that each Reliability Coordinator provides a Reliability Plan to the NERC Operating Committee for its approval. That Reliability Plan must address the requirements listed in the NERC Template for Developing a Reliability Coordinator Reliability Plan document. Through regional participation of its Reliability Coordinators, the Regional Operating Reliability Plan can serve as the Reliability Coordinator Reliability Plan.

    2.1. **Multiple Reliability Coordinators operating within the Regional Council.** If the Regional Council's Regional Operating Reliability Plan indicates that more than one Reliability Coordinator operates within the Region, the Regional Council's Regional Operating Reliability Plan shall address the interrelationships among the Reliability Coordinators within its boundary, and how those Reliability Coordinators coordinate their operations with one another and with their adjacent Reliability Coordinators in other Regional Councils. The Regional Council's Regional Operating Reliability Plan can incorporate the coordination information for both its and adjacent Reliability Coordinators.

        2.1.1. **Communications**. The Regional Operating Reliability Plan shall document how the Reliability Coordinators will communicate with each other and with Reliability Coordinators in other Regional Councils.

        2.1.2. **Delegation of tasks**. If reliability coordination requires the delegation of tasks, the Regional Council shall document how that delegation is accomplished. The Regional Council shall also explain that the responsibilities of the delegated tasks remain with the individual Reliability Coordinators.

        2.1.3. **Coordination**. The Regional Operating Reliability Plan shall document how the Reliability Coordinators will coordinate their operations, including the mitigation of System Operating Limit violations and Interconnected Reliability Operating Limit violations along their boundaries. A list of all operating agreements between the Reliability Coordinators within the Regional Council and a list of all operating agreements with Reliability Coordinators in other Regional Councils shall be provided in the Regional Operating Reliability Plan.

        2.1.4. **Feasibility.** The Regional Operating Reliability Plan must be feasible in the opinion of the NERC Operating Committee. While feasibility is subjective, it includes the following attributes that must be considered together:

        2.1.5. Manageable number of Reliability Coordinators

            - Ability of each Reliability Coordinator to have the real-time "big picture," or Wide Area view

            - Ability of each Reliability Coordinator to calculate Interconnected Reliability Operating Limits and mitigate IROL violations

- Ability of the Reliability Coordinators to communicate effectively among themselves and with Reliability Coordinators in other Regional Councils

3. **Compliance with NERC Reliability Standards**. The Regional Council shall monitor all Reliability Coordinators within its boundary for compliance with NERC Reliability Standards.

   3.1. **Compliance procedures.** The Regional Council shall provide to NERC the procedure it uses to ensure and verify the Reliability Coordinators' compliance with NERC Reliability Standards.

   3.2. **Reliability Coordinator Audits**. The Regional Council shall ensure that each Reliability Coordinator is audited in accordance with the directives of the NERC Vice President of Compliance.

   3.3. **Corrective actions.** The Regional Council shall ensure that the Reliability Coordinator mitigates any instances of non-compliance with NERC Reliability Standards identified in a Reliability Coordinator Audit.

Comments

Edward J. Davis Entergy	Almost all the entries in this section should be included in the RC Reliability Plan or in the review and endorsement of those Plans. The above entries should not be in this Regional Operating Reliability Plan. The entry 2.1.4 Feasibility should be an action item for the NERC Operating Committee to establish guidelines for all RC Reliability Plans because each of those Plans must be feasible with respect to all other RC Plans, not just those Plans in this particular Region. The "feasibility" test used by the OC should be much better defined with much more detail than the statement included in this section. Therefore, we suggest this whole section be replaced with the following: "B. Reliability Coordination Plan 1. The Regional Council shall review the new or revised Reliability Coordinator Reliability Plan submitted to it by each Reliability Coordinator in the Region. Each RC is required by the NERC Template for Developing a Reliability Coordinator Reliability Plan to submit a new or revised plan to the Council. 2. The Regional Council shall endorse those new or revised RC Reliability Plans when they meet the requirements of the NERC Standards. 3. The Regional Council shall provide a list of the Reliability Coordinators within the Regional Council's boundary and shall update that list when it changes. 4. The Regional Council shall provide to the NERC Operating Committee each of the endorsed RC Reliability Plans. 5. The Regional Council shall monitor all Reliability Coordinators within its boundary for compliance with NERC Reliability Standards. 6. The Regional Council shall prepare and provide to NERC the procedure it uses to ensure and verify the Reliability Coordinators' compliance with NERC Reliability Standards. 7. The Regional Council shall ensure each Reliability Coordinator is audited in accordance with the directives of the NERC Vice-President of Compliance. 8. The Regional Council shall ensure the Reliability Coordinator mitigates any instances of non-compliance with NERC Reliability Standards identified in a Reliability Coordinator audit."

Alan Boesch NPPD	These plan requirements fail to recognize the function that the Transmission Operator plays in bulk electric system reliability.
Pete Henderson IESO Karl Tammar NYISO	The above requirements would be better located in the template for the Reliability Coordinator Reliability Plan(RC RP). (alternatively, the RC RP template requirements could be included here.) It makes little sense to have both a RC RP and a Regional Operating Plan which are addressing the same subject. Otherwise, this will create extra workload and poses the potential for inconsistency between the two.
Thomas V. Pruitt Duke	Subsection 3.2 – The Regional Councils are required to perform audits at the direction of the NERC VP of Compliance. We do not agree. The RC Plan and BA Plan Templates more fully qualify such times (initial plan implementation or membership change or change in scope) that the VP may order an audit. All other audits on aperiodic basis as determinde by the Board of Trustees. A standardized, open process for determining when and how audits should occur should exist. Further, these words are not consistent with the wording in the following section dealing with auditing of Balancing Authorities (subsection 3.1).

Regional Operating Reliability Plan Requirements — Balancing Authorities

1. **Balancing Authority Integrated Operational Plan.** The Regional Council shall ensure that each Balancing Authority, certified to operate within its Regional Council boundary, has developed a Balancing Authority Integrated Operational Plan that addresses the requirements identified in the NERC Template for Developing a Balancing Authority Integrated Operational Plan document.

    1.1. **Balancing Authority Integrated Operational Plan Approval.** The Regional Council shall ensure that each Balancing Authority provides an Integrated Operational Plan to the Region for its approval.

2. **Balancing Authority boundaries.** The Regional Council shall ensure that every generator, transmission facility, and customer is within the metered boundaries of a single Balancing Authority.

    2.1. **Contiguity of Balancing Authority Areas**. The Regional Council shall ensure that Balancing Authority Areas do not overlap.

    2.2. **Reliability Coordinator purview**. The Regional Council shall ensure that every Balancing Authority is within the purview of a single Reliability Coordinator.

3. **Compliance with NERC Reliability Standards**. The Regional Council shall monitor all Balancing Authorities within its boundary for compliance with NERC Reliability Standards.

    3.1. **Compliance procedures.** The Regional Council shall provide the procedure it uses to ensure and verify the Balancing Authorities' compliance with NERC Reliability Standards to the NERC Vice President of Compliance

    3.2. **Corrective actions.** The Regional Council shall ensure that the Balancing Authority mitigates any instances of non-compliance with NERC Reliability Standards identified by the Regional Council.

Comments

Edward J. Davis Entergy	We suggest this whole section be replaced with the following: C. Balancing Authority Boundaries 1. The Regional Council shall develop and document a process for ensuring that every generator, transmission facility, and all retail customers are within the metered boundaries of a BA. 2. The Regional Council shall ensure that BA Areas do not overlap. 3. The Regional Council shall ensure that every BA Area is within the purview of a single Reliability Coordinator. D. Balancing Authority Integrated Operational Plan 1. The Regional Council shall review the new or revised BA IOP submitted to it by each BA in the Region as required by the NERC Template for Developing a Balancing Authority Integrated Operational Plan. 2. The Regional Council shall endorse those new or revised BA IOP when they meet the requirements of NERC Standards. E. Balancing Authority Compliance Oversight 1. The Regional Council shall develop and provide to the NERC Vice-President of

	Compliance the procedure it uses to ensure and verify each BA's compliance with NERC Reliability Standard. 2. The Regional Council shall monitor all BAs within its boundary for compliance with NERC Reliability Standards. 3. The Regional Council shall ensure the BA mitigates any instances of non-compliance with NERC Reliability Standards identified by the Regional Council."
Alan Boesch NPPD	See the comments in the BA IOP document. This plan fails to recognize the function of the Transmission Operator. The BA is not a one for one replacement of the Control Area.
Pete Henderson IESO Karl Tammar NYISO	The above requirements would be better located in the template for the Balancing Authority Plan (BA Pn). (Alternatively, the BA Pn template requirements could be included here.)

Template for Developing a Reliability Coordinator Reliability Plan

Draft 5

Highlighted Comments from the WECC RCS (Reliability Coordination Subcommittee)

General Comments

Kathleen H. Bauer NorthWestern Energy	In the February 2003 version, NERC Policy 6 still refers to the need for a "plan to continue operation in the event its control center becomes inoperable". NorthWestern Energy (NWE) has a plan and is in the process of implementing that plan. While we have the ability to operate from a remote control center, that plan presumes that our communication structure remains intact. NWE continues to work to get to a fully operational state in the event our control center becomes inoperable. According to the Balancing Authority template, however, we will have to demonstrate in our "integrated operational plan" that is subject of the template, that we (Balancing Authorities) have "the processes and procedures in place to insure the performance of its reliability functions in the event it loses control center functionality." This would seem to say we need more than a plan. Our concern is that the language in the Balancing Authority template is requiring something that the Policy does not. Is that the intent of this template? Further clarification would be prudent and appreciated. Thank you for the opportunity to comment on these templates.

Reliability Plan Subsections

A. Responsibilities – Authorization
B. Responsibilities – Delegation of Tasks
C. Common Tasks for Current-Day and Next-Day Operations
D. Next-Day Operations
E. Current-Day Operations
F. Emergency Operations
G. System Restoration
H. Coordination Agreements and Data Sharing
I. Facility
J. Staffing

Introduction

This document outlines the requirements that a RELIABILITY COORDINATOR shall address in its Reliability Plan.

Initial Reliability Coordinator's Reliability Plan

A RELIABILITY COORDINATOR shall prepare a Reliability Plan in accordance with this template that documents that it has the processes, procedures, tools, and agreements in place to perform the reliability functions and responsibilities assigned to RELIABILITY COORDINATORS in the Operating Policies or the successor Version 0 Reliability Standards. The initial Reliability Plan will outline the physical boundaries of its Reliability Coordinator Area. The term Reliability Coordinator may include more than one Reliability Coordinator if the Reliability Plan covers an entire Interconnection.

Approval process for changes to a Reliability Coordinator's Reliability Coordinator Area

Changes to a RELIABILITY COORDINATOR'S Reliability Coordinator Area must be:

1. Endorsed by the applicable NERC Region(s),
2. Accompanied by an update of all impacted Regional Council's Regional Operating Reliability Plans to reflect the Reliability Coordinator Area remaining within the Regional Council's purview.
3. Submitted to the Operating Reliability Subcommittee for review as an amendment to the Reliability Coordinator's Reliability Plan.
4. The Operating Reliability Subcommittee forwards the results of its review to the NERC Operating Committee.
5. Approved by Operating Committee before implementation, or in the alternative.
6. Be approved by an Interconnection wide Regional Reliability Organization.

Reliability Coordinator's Reliability Plan Approval Process

The RELIABILITY COORDINATOR shall submit its initial or revised Reliability Plan to all Regional Reliability Councils, within which the RELIABILITY COORDINATOR will operate, and the Operating Committee or, in the alternative to the Interconnection wide Regional Reliability Organization for endorsement. The Board of Trustees will, if applicable, review the Operating Committee's recommendation in instances where a state, federal or provincial legislative or regulatory body requires notification of NERC's endorsement of the RELIABILITY COORDINATOR'S Reliability Plan.

The Operating Committee or, in the alternative a Regional Reliability Organization for an Interconnection Wide Reliability Coordinator, shall endorse all revisions to a RELIABILITY COORDINATOR'S Reliability Plan prior to implementation of the proposed revision.

Reliability Coordinator Audits

The RELIABILITY COORDINATOR shall be audited at the direction of the NERC Vice President of Compliance prior to implementing its initial Reliability Plan, and on a periodic basis thereafter as determined by the NERC Board of Trustees, or in the alternative an audit may be conducted by an Interconnection wide Regional Reliability Organization whose results will be made available to NERC.

The RELIABILITY COORDINATOR may be audited at the direction of the NERC Vice President of Compliance or, in the alternative by an Interconnection wide Regional Reliability Organization when any of the following events occurs within a RELIABILITY COORDINATOR'S Reliability Coordinator Area:

1. A change in RELIABILITY COORDINATOR membership resulting in a change in the Reliability Coordinator Area.
2. A change in scope within the RELIABILITY COORDINATOR'S Reliability Coordinator Area, e.g. the start-up of a market operation.

Comments

Donald S. Watkins BPA	We propose that this be modified to provide such that **alternatively**, the plan would be approved by the Regional reliability Council to which the plan applies and if that council covers the entire interconnection. The plan would then be required to be sent to the appropriate NERC parties as information.
Roman Carter Marc Butts	Southern Company Generation cautions that this Guide for Developing a NERC Reliability Coordinator Reliability Plan should not be confused with Planning

Southern	Templates or Compliance Templates and therefore should be referred to as a "Guide or Reference Document" to make a clear distinction between the NERC Templates and this Guide. Under Reliability Coordinator Audits, it is stated that "the Reliability Coordinator (RC) shall be audited at the direction of the NERC Vice President of Compliance prior to implementing its intial Reliability Plan". This statement is not supported by NERC policy and is not contained in the Version 0 Standards. What is the basis for this change? Should the audits be at the direction of the Regional Reliability Council in which the RC operates? It is unclear what constitutes a change in membership and a change in scope within the RC's area. The actual RC Reliability Plan should contain more specifics (i.e., electrical changes, geographical changes, etc.) about this before being adopted. What is the required frequency of these audits? After every change, once a year, etc.? Also, will a change in the Plan be required for each auditable instance or will the changes be incorporated in the Yearly Plan?
Edward J. Davis Entergy	We have several overall comments on this document and then several comments specific to this section. A. OVERALL COMMENTS 1. Please delete all references to Operating Policies and successor Version 0 Realibility Standards. While this terminology was previously appropriate it is no longer appropriate since NERC will have Board approved Standards long before this standard is approved. 2. Therefore, add to the introductory table of contents and to each appropriate place in the text the specific new NERC Standards numbers to which the RC Reliability Plan should conform. 3. We strongly recommend deleting from this Template the details of what should be contained in a Plan since the details are already contained in the Standards. Again, while including details in this document may have been appropriate at the time it was initially developed, it is no longer appropriate since the industry will soon have Board approved Standards. In general, most of the text of this Template consists of re-iteration of the NERC Operating Policies, or the new NERC Standards. There is no need to do that re-iteration as the details are in the Standards to which the entity should conform. B. SPECIFIC COMMENTS ON THIS SECTION 4. This section should be entitled "A1. Reliability Plan Approval Process and Approval Requirements" and a new title added to the table of contents. This section specifies and details the requirements that a RC develop a Reliability Plan, what is to be done with that required Plan, and what entities "endorse" the Plan. Everything else in this Template specifies what must be in the Plan. 5. Add to the beginning of the "Introduction" the following statement: "This section outlines the process the industry will use to have that Reliability Coordinator Plan reviewed and endorsed." 6. Delete "Initial" from the title "Initial Reliability Coordinator's Reliability Plan". 7. Revise the third line of the "Initial Reliability Coordinator's Reliability Plan" by replacing the phrase "…in the Operating Policies or the successor Version 0 Reliability Standards." with the phrase "…in the NERC Standards". 8. Delete the section "Approval Process for Changes to a Reliability Coordinaotr's Reliability Coordinator Area Area" and change section "Reliability Coordinator's

	Reliability Plan Approval Process" as detailed in number 9 below. 9. Add to the end of the existing section "Reliability Coordinator's Reliability Plan Approval Process" as follows: "The new or revised Reliability Plan shall be reviewed by the applicable NERC Regional Reliability Councils and endorsed by those Councils when the Plan meets the requirements of the NERC Standards. The RRO shall add this endorsed Plan to its Regional Operating Reliability Plan and submit that Regional Plan to NERC. The new or revised Reliability Coordinator's Reliability Plan shall also be submitted to the NERC Operating Reliability Subcommittee for review. The result of that review shall be forwarded to the NERC Operating Committee. The Operating Committee shall endorse the Plan, prior to implementation, when the Plan meets the requirements of the NERC Standards." 10. Please delete the following sentence in "Reliability Coordinator's Reliability Plan Approval Process" - "The Operating Committee shall endorse all revisions to a Reliability Coordinator's Reliability Plan prior to implementation of the proposed revision." 11. In the section "Reliability Coordinator Audits" replace "A change in the Reliability Coordinator membership…" with "A change in the Reliability Coordinator's Area, or Generation Owner, Transmission Owner, or Load Serving Entity within those meterd boundaries…" 12. Please give more details about what constitutes a "change in scope" within the RCs Area. The given statement is too vague in general and absolutely too vague for a Standard, to understand what is meant by that phrase.
Pete Henderson IESO Karl Tammar NYISO	Audit Requirements and expectations must be clearly defined. Changes in RC area need better definition, i.e. would a new, small CA "carved out" from a larger CA require an RC audit? . Starting up of a market operation would not effect RC operations and therefore not automatically trigger an audit. The document should provide the timelines for implementation of this template and provide NERC's expectations of Reliability Coordinators to evolve existing RC plans to this format.
Thomas V. Pruitt Duke	This comment applies to all sections of this document and the BA Plan Template as well. The document should be reformatted to be consistent with the new Version 0 standards (i.e., the organization and order should match the structure of the Version 0 standards – all TOP standard related topics together and in numerical order, and so on). This comment also applies to all sections of this document and the BA Plan Template as well. All references to current Operating Policy should be changed to the corresponding Version 0 standards. Translation to Version 0 needs to occur as soon as possible to minimize the work currently underway by several entitites to rewrite their plans.
Greg Tillitson CAISO WECC RCS	This template should provide only a high-level outline (or table off contents) for what NERC expects the Regions to include in their Reliability Plan. It should not list the requirements (standards) for the RC, as these are covered by the soon to be implemented Version 0 standards and compliance templates. Including requirements in this template creates the potential of having inconsistencies is relation to the standards. As for comments regarding what is presented in this document, the audit requirements and expectations are not clearly defined. As an example, would a new, small Control Area (BA) “carved out” from a larger Control Area require a RC audit? Starting up a market operation would not necessarily effect RC

	operations in the WECC and therefore should not automatically trigger an audit.

A. Responsibilities – Authorization

The RELIABILITY COORDINATOR shall provide documentation within its Reliability Plan that it has the authorization of GENERATOR OPERATORS, TRANSMISSION OPERATORS, LOAD-SERVING ENTITIES, PURCHASING-SELLING ENTITIES, BALANCING AUTHORITIES, and TRANSMISSION SERVICE PROVIDERS within its RELIABILITY COORDINATOR AREA to perform the following responsibilities:

1. The Reliability Plan shall document that the RELIABILITY COORDINATOR is responsible for the reliable operation of the BULK ELECTRIC SYSTEM in accordance with NERC, Regional and sub-Regional practices within its RELIABILITY COORDINATOR AREA. (Policy 9 Requirement A.1)

    1.1. The Reliability Plan shall document that the RELIABILITY COORDINATOR has a WIDE AREA view, the operating tools, processes and procedures, including the authority, to prevent or mitigate emergency operating situations in both next-day analysis and during real-time conditions. (Policy 9 Requirement A.1.1)

    1.2. The Reliability Plan shall document that the RELIABILITY COORDINATOR has clear decision-making authority to act and to direct actions to be taken by BALANCING AUTHORITIES, GENERATOR OPERATORS, TRANSMISSION OPERATORS, TRANSMISSION SERVICE PROVIDERS, LOAD-SERVING ENTITIES, and PURCHASING-SELLING ENTITIES within its RELIABILITY COORDINATOR AREA to preserve the integrity and reliability of the BULK ELECTRIC SYSTEM. (Policy 9 Requirement A.1.2)

    1.3. The Reliability Plan shall document that the RELIABILITY COORDINATOR has not delegated its responsibilities. (Policy 9 Requirement A.1.3)

2. The Reliability Plan shall document that the RELIABILITY COORDINATOR will act in the interests of reliability for the overall RELIABILITY COORDINATOR AREA and its INTERCONNECTION before the interests of any other entity. (Policy 9 Requirement A.2)

3. The Reliability Plan shall document how all BALANCING AUTHORITIES, GENERATOR OPERATORS, TRANSMISSION OPERATORS, TRANSMISSION SERVICE PROVIDERS, LOAD-SERVING ENTITIES, and PURCHASING-SELLING ENTITIES within its RELIABILITY COORDINATOR AREA shall comply with its directives unless such actions would violate safety, equipment, or regulatory or statutory requirements. The Reliability Plan shall document that under these circumstances the BALANCING AUTHORITY, GENERATOR OPERATOR, TRANSMISSION OPERATOR, TRANSMISSION SERVICE PROVIDER, LOAD-SERVING ENTITY, and PURCHASING-SELLING ENTITY must immediately inform the RELIABILITY COORDINATOR of the inability to perform the directive so that it may implement alternate remedial actions. (Policy 9 Requirement A.3)

Comments

Donald S. Watkins BPA	Given that there are several different structures across N. America for Reliablity Coordinators, Reliability Authorities, and Transmission Operators, we propose that a section be added to clearly specify what entities have what responsibilities, functions, and authorities. We assume that the procedures included in a plan allow delegation of tasks such as a Reliability Coordinator directing a Transmission operator to direct a LSE to shed load.
Edward J. Davis Entergy	1. The RC should provide documentation that it has authorization from all entities within its RC Area. The bold lead in statement above does not contain a

	complete list of entities from which the RC must receive authorization. The list above is missing Tranmisssion Owners and Generation Owners. RCs must receive authorization from Owners of the facilities, not Operators of facilities. 2. Delete all of items 1 through 3. The details in these items repeat the details enumerated in the Standards and are unnecessary. Additionally, if additional requirements are contained in the above they would inappropriately impose new requirements on the RC if they are included in this Template and are not included in the Standard. Therefore the above should be deleted. 3. Please change the bold lead in statement above from "…within its Reliability Coordinator Area to perform the following responsibilities:" to "…within its Reliability Coordinator Area to perform the responsibilities identified in the NERC Standards." 4. If desired, this section may contain a list of the titles of each of the NERC Standards that requires interaction between the RCs and each of the entities identified in the bold lead in statement. However, this section should not contain a detailed list of the Requirements contained in the Standards, nor should it contain a subset of those requirements.
Pete Henderson IESO Karl Tammar NYISO	This template should provide only an outline or Table Of Contents of what is expected to be covered by the Reliability Plan as a guide for the developers of the RC Plans. It should not list requirements for the RC, as these should be covered by the soon to be implemented Version 0 standards. Templates approved outside the Standard Process create the potential of having inconsistent requirements or of adding new requirements that are not part of the standards. The Reliability Plans should clearly address how the RC meets the standards rather than restating them and saying he does.
Greg Tillitson CAISO WECC RCS	It should be recognized that in the WECC the RC may have agreements only with Control Areas or Transmission Operator to carry out certain functions, such as shedding of load or re-dispatching generation. The agreements would not necessarily be between the RC and the LSE or Generator Operator. These entities are required to carry out these RC instructions or directives because of their agreements with the Control Area or Transmission Operator. References to Policy 9 need to be remapped to the responsibilities of Version 0 standards.

B. Responsibilities – Delegation of Tasks

The RELIABILITY COORDINATOR shall document within its Reliability Plan its delegation of tasks to other entities, including a listing of those entities. The RELIABILITY COORDINATOR shall document within its Reliability Plan how it ensures that all delegated tasks are understood, communicated, and addressed within its RELIABILITY COORDINATOR AREA.

The RELIABILITY COORDINATOR shall document within its Reliability Plan that NERC or in the alternative an Interconnection wide Regional Reliability Organization -certified RELIABILITY COORDINATOR operators are performing all delegated tasks. (Policy 9 Requirement B.1, B.2, B.3, and B.4)

Comments

Edward J. Davis Entergy	We suggest moving the last sentence into the bold section.
Pete Henderson IESO Karl Tammar NYISO	The SRC supports having a single entity for a specified area to have the overall accountability for reliability. However, it needs to be recognized that in some areas (e.g. in WECC) the RC may need agreements with other parties, such as BAs, TOPs, etc to carry out certain functions, such as shedding of load.
Greg Tillitson CAISO WECC RCS	The template lists requirements that should be in the Standards; there is no need for them here. This template should only be a high level outline of what aspects the RC Plan should address.

C. Common Tasks for Next-Day and Current-Day Operations

The RELIABILITY COORDINATOR'S Reliability Plan shall document how it conducts next-day and current-day reliability analysis within in its RELIABILITY COORDINATOR AREA. At a minimum this documentation shall address the following:

The RELIABILITY PLAN shall document how the RELIABILITY COORDINATOR coordinates operations in regards to SOLs and IROLs for real time and next-day operations for its RELIABILITY COORDINATOR AREA including thermal, voltage and stability related analysis. The Reliability Plan shall document how the results, (e.g. identification of SOL violations) of reliability assessments, up to and including next-day assessments, conducted by TRANSMISSION OPERATORS, are reported to the RELIABILITY COORDINATOR. The RELIABILITY COORDINATOR shall ensure that its WIDE AREA view is modeled to ensure coordinated operations. (Policy 9 Requirement C.1.1)

1. The RELIABILITY COORDINATOR shall document the processes it uses to determine IROLs. This documentation shall address the processes the RELIABILITY COORDINATOR uses to ensure that it becomes aware of an IROL violation created by the outage of multiple, normally non-critical facilities. The Reliability Plan shall document how the RELIABILITY COORDINATOR will disseminate the results of these analyses within its RELIABILITY COORDINATOR AREA and to neighboring RELIABILITY COORDINATORS IF ANY WITHIN AN INTERCONNECTION. (Policy 9 Requirement C.1.2)

2. The Reliability Plan shall document how the RELIABILITY COORDINATOR ensures that all BALANCING AUTHORITIES, GENERATOR OPERATORS, TRANSMISSION OPERATORS, TRANSMISSION SERVICE PROVIDERS, LOAD-SERVING ENTITIES, and PURCHASING-SELLING ENTITIES operate to prevent the likelihood that a disturbance, action, or non-action in its RELIABILITY COORDINATOR AREA will result in a SOL or IROL violation in another area of the INTERCONNECTION. The Reliability Plan shall document how the RELIABILITY COORDINATOR will operate in instances where there is a difference in derived limits. (Policy 9 Requirement C.1.3 and Policy 5 Requirement A.6)

3. The Reliability Plan shall document how the RELIABILITY COORDINATOR ensures that its BALANCING AUTHORITIES and TRANSMISSION OPERATORS are always operating under known and studied conditions and also how it ensures that they reassess and reposture their systems following CONTINGENCY events without delay, and no longer than 30 minutes, regardless of the number of CONTINGENCY events that occur or the status of their monitoring, operating and analysis tools. (Policy 9 Requirement C.1.4)

4. The Reliability Plan shall document how the RELIABILITY COORDINATOR makes known to TRANSMISSION SERVICE PROVIDERS within its RELIABILITY COORDINATOR AREA, SOLs or IROLs within its WIDE AREA view. (Policy 9 Requirement C.1.5)

5. The Reliability Plan shall document the process the RELIABILITY COORDINATOR uses to issue directives in a clear, concise, definitive manner within its RELIABILITY COORDINATOR AREA. (Policy 9 Requirement C.1.6)

Comments

Donald S. Watkins BPA	We assume in this that some tasks such as calculating IROLs as appropriate, etc. may be delegated.
Edward J. Davis Entergy	Please change the bold lead in section from "…how it conducts next-day and current-day…" to "…how it conducts common tasks to meet NERC Standards for next-day and current-day …". Delete the phrase "At a mimimum this

	documentation shall address the following:". 2. Delete all of items 1 through 5. The details in these items repeat the details enumerated in the Standards and are unnecessary. Additionally, if additional requirements are contained in the above they would inappropriately impose new requirements on the RC if they are included in this Template and are not included in the Standard. Therefore the above should be deleted. 3. If desired, this section may contain a list of the titles of each of the NERC Standards that requires interaction between the RCs and each of the entities identified in each of the Standards. However, this section should not contain a detailed list of the Requirements contained in the Standards, nor should it contain a subset of those requirements.
Pete Henderson IESO Karl Tammar NYISO	See comments for item A. This lists requirements that should be in the standards & hence there is no need for them here. This template should only be a high level outline of what aspects the RC Plan should address.
Greg Tillitson CAISO WECC RCS	The template lists requirements that should be in the Standards; there is no need for them here. This template should only be a high level outline of what aspects the RC Plan should address.

D. Next-Day Operations

The Reliability Plan shall document how the RELIABILITY COORDINATOR conducts next-day reliability analyses for its RELIABILITY COORDINATOR AREA to ensure that the BULK ELECTRIC SYSTEM can be operated reliably in anticipated normal and CONTINGENCY event conditions. At a minimum this documentation shall address the following:

1. The Reliability Plan shall document how the RELIABILITY COORDINATOR conducts CONTINGENCY analysis studies to identify potential interface and other SOL and IROL violations, including overloaded transmission lines and transformers, voltage and stability limits, etc. (Policy 9 Requirement D.1.1)

    1.1. The Reliability Plan shall document how the RELIABILITY COORDINATOR ensures that the impact of parallel flows from its RELIABILITY COORDINATOR AREA does not place an unacceptable or undue BURDEN on an adjacent RELIABILITY COORDINATOR AREA WITHIN ITS INTERCONNECTION. (Policy 9 Requirement D.1.2)

2. The Reliability Plan shall document the process used to obtain the information required for system studies, such as critical facility status, load, generation, operating reserve projections, and known INTERCHANGE TRANSACTIONS from BALANCING AUTHORITIES, INTERCHANGE AUTHORITIES, TRANSMISSION OWNERS, TRANSMISSION OPERATORS, GENERATION OWNERS, GENERATION OPERATORS, and LOAD-SERVING ENTITIES within its RELIABILITY COORDINATOR AREA. (Policy 9 Requirement D.2)

3. The RELIABILITY COORDINATOR shall document the process it uses to share the results of its system studies, when conditions warrant or upon request, with other RELIABILITY COORDINATORS, and BALANCING AUTHORITIES, TRANSMISSION OPERATORS, GENERATION OPERATORS, and TRANSMISSION SERVICE PROVIDERS within its RELIABILITY COORDINATOR AREA. (Policy 9 Requirement D.4)

4. The Reliability Plan shall document the conditions that warrant the initiation of a conference call or other appropriate communications to address the results of its reliability analyses. (Policy 9 Requirement D.5)

Comments

Edward J. Davis Entergy	1. Please change the bold lead in section from "…how it conducts next-day reliability analyses for…" to "…how it conducts next-day reliability analyses to meet NERC Standards for…" Delete the phrase "At a minimum this documentation shall address the following:". 2. Delete all of items 1 through 4. The details in these items repeat the details enumerated in the Standards and are unnecessary. Additionally, if additional requirements are contained in the above they would inappropriately impose new requirements on the RC if they are included in this Template and are not included in the Standard. Therefore the above should be deleted. 3. If desired, this section may contain a list of the titles of each of the NERC Standards that requires interaction between the RCs and each of the entities identified in each of the Standards. However, this section should not contain a detailed list of the Requirements contained in the Standards, nor should it contain a subset of those requirements.
Pete Henderson	See comments for item A. This lists requirements that should be in the standards &

IESO Karl Tammar NYISO	hence there is no need for them here. This template should only be a high level outline of what aspects the RC Plan should address.
Greg Tillitson CAISO WECC RCS	Provisions should be made for delegation of determining IROLs. The template lists requirements that should be in the Standards; there is no need for them here. This template should only be a high level outline of what aspects the RC Plan should address

E. Current-Day Operations

The Reliability Plan shall document how the RELIABILITY COORDINATOR conducts current-day reliability analyses for its RELIABILITY COORDINATOR AREA to ensure that the BULK ELECTRIC SYSTEM can be operated reliably in anticipated normal and CONTINGENCY event conditions. At a minimum this documentation shall address the following:

1. The Reliability Plan shall document the process the RELIABILITY COORDINATOR uses to monitor all BULK ELECTRIC SYSTEM facilities, including sub-transmission information, within its RELIABILITY COORDINATOR AREA and adjacent RELIABILITY COORDINATOR AREAS as necessary to ensure that, at any time, regardless of prior planned or unplanned events, the RELIABILITY COORDINATOR is able to determine any potential SOL and IROL violations within its RELIABILITY COORDINATOR AREA. (Policy 9 Requirement E.1.1)

    1.1. The Reliability Plan shall document the process used to notify a neighboring RELIABILITY COORDINATOR of an operational concern (e.g. declining voltages, excessive reactive flows, or an IROL violation) that it identifies within the neighboring RELIABILITY COORDINATOR'S RELIABILITY COORDINATOR AREA. The Reliability Plan shall document how the RELIABILITY COORDINATOR shall coordinate any actions with neighboring RELIABILITY COORDINATORS, including the provision of emergency assistance, required to mitigate the operational concern. (Policy 9 Requirement E.1.1.1)

2. The Reliability Plan shall document how the RELIABILITY COORDINATOR maintains awareness of the status of all current critical facilities whose failure, degradation or disconnection could result in an SOL or IROL violation within its RELIABILITY COORDINATOR AREA. The Reliability Plan shall also document how the RELIABILITY COORDINATOR maintains awareness of the status of any facilities that may be required to assist RELIABILITY COORDINATOR AREA restoration objectives. (Policy 9 Requirement E.1.2)

3. The Reliability Plan shall document the processes the RELIABILITY COORDINATOR uses to be continuously aware of conditions within its RELIABILITY COORDINATOR AREA and how the RELIABILITY COORDINATOR includes this information in its reliability assessments. The Reliability Plan shall document how the RELIABILITY COORDINATOR monitors its RELIABILITY COORDINATOR AREA parameters, including but not limited to the following (Policy 9 Requirement E.1.3):

    3.1. Current status of BULK ELECTRIC SYSTEM elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Special Protection Systems and system loading

    3.2. Current pre-CONTINGENCY element conditions (voltage, thermal, or stability)

    3.3. Current post- CONTINGENCY element conditions (voltage, thermal, or stability)

    3.4. System real and reactive reserves (actual versus required)

    3.5. Capacity and energy adequacy conditions

    3.6. Current ACE for all its BALANCING AUTHORITIES

    3.7. Current local or TLR procedures in effect

    3.8. Planned generation dispatches

    3.9. Planned transmission or generation outages

3.10. CONTINGENCY events

4. The Reliability Plan shall document the process the RELIABILITY COORDINATOR uses to monitor BULK ELECTRIC SYSTEM parameters that may have significant impacts upon its RELIABILITY COORDINATOR AREA and neighboring RELIABILITY COORDINATOR AREAS with respect to (Policy 9 Requirement E.1.4):

4.1. The Reliability Plan shall document how the RELIABILITY COORDINATOR maintains awareness of all INTERCHANGE TRANSACTIONS that wheel-through, source, or sink in its RELIABILITY COORDINATOR AREA and how the RELIABILITY COORDINATOR makes that INTERCHANGE TRANSACTION information available to all RELIABILITY COORDINATORS in the INTERCONNECTION.

4.2. The Reliability Plan shall document how the RELIABILITY COORDINATOR, in concert with the BALANCING and INTERCHANGE AUTHORITIES within its RELIABILITY COORDINATOR AREA evaluates and assesses any additional INTERCHANGE SCHEDULES that would violate SOLS OR IROLS. The Reliability Plan shall document that the RELIABILITY COORDINATOR is authorized to utilize all resources, including load shedding, to address a potential or actual IROL violation.

4.3. The Reliability Plan shall document how the RELIABILITY COORDINATOR monitors BALANCING AUTHORITY parameters to ensure that the required amount of OPERATING RESERVES are provided and available as required to meet NERC Control Performance Standard and Disturbance Control Standards. The Reliability Plan shall document that, if necessary, the RELIABILITY COORDINATOR will direct the BALANCING AUTHORITIES in its RELIABILITY COORDINATOR AREA to arrange for assistance from neighboring BALANCING AUTHORITIES.

4.4. The Reliability Plan shall document how the RELIABILITY COORDINATOR identifies the cause of potential or actual SOL or IROL violations. The Reliability Plan shall document how the RELIABILITY COORDINATOR shall initiate control actions or emergency procedures to relieve the potential or actual IROL violation without delay, and no longer than 30 minutes. The Reliability Plan shall document that the RELIABILITY COORDINATOR is authorized to direct utilization of all resources, including load shedding, to address a potential or actual IROL violation.

4.5. The Reliability Plan shall document how the RELIABILITY COORDINATOR will communicate start and end times for time error corrections to all BALANCING AUTHORITIES within its RELIABILITY COORDINATOR AREA. The Reliability Plan shall document how the RELIABILITY COORDINATOR will ensure that all BALANCING AUTHORITIES, TRANSMISSION OPERATORS, and GENERATION OPERATORS within its RELIABILITY COORDINATOR AREA are aware of Geo-Magnetic Disturbance (GMD) forecast information and how the RELIABILITY COORDINATOR will assist in the development of any required response plans.

4.6. The Reliability Plan shall document that the RELIABILITY COORDINATOR will participate in NERC Hotline discussions, assist in the assessment of reliability of the Regions and the overall interconnected system, and coordinate actions in anticipated or actual emergency situations. The Reliability Plan shall document how the RELIABILITY COORDINATOR will disseminate this information within its RELIABILITY COORDINATOR AREA.

4.7. The Reliability Plan shall document how the RELIABILITY COORDINATOR monitors system frequency and its BALANCING AUTHORITIES' performance, and the procedures the RELIABILITY COORDINATOR will follow for directing any necessary rebalancing to return to CPS and DCS compliance. The Reliability Plan shall document that at the direction of the

RELIABILITY COORDINATOR its BALANCING AUTHORITIES shall utilize all resources, including firm load shedding, to relieve the emergent condition.

4.8. The Reliability Plan shall document how the RELIABILITY COORDINATOR coordinates with other RELIABILITY COORDINATORS and BALANCING AUTHORITIES, GENERATION OPERATORS, and TRANSMISSION OPERATORS, as needed, the development and implementation of action plans to mitigate potential or actual SOL, IROL, CPS or DCS violations. The Reliability Plan shall document how the RELIABILITY COORDINATOR coordinates pending generation and transmission maintenance outages with other RELIABILITY COORDINATORS and BALANCING AUTHORITIES, GENERATION OPERATORS, and TRANSMISSION OPERATORS, as needed, in both the real time and next-day reliability analysis timeframes.

4.9. The Reliability Plan shall document how the RELIABILITY COORDINATOR will assist the BALANCING AUTHORITIES in its RELIABILITY COORDINATOR AREA in arranging for assistance from neighboring RELIABILITY COORDINATORS or BALANCING AUTHORITIES.

4.10. The Reliability Plan shall document how the RELIABILITY COORDINATOR identifies sources of large AREA CONTROL ERRORS that may be contributing to frequency, time error, or inadvertent interchange and the procedures the RELIABILITY COORDINATOR shall follow to implement corrective actions with the appropriate BALANCING AUTHORITY.

4.11. The Reliability Plan shall document how the RELIABILITY COORDINATOR maintains awareness that a Special Protection System that may impact an inter-BALANCING AUTHORITY, inter-TRANSMISSION OPERATOR, or inter-RELIABILITY COORDINATOR AREA (e.g. could potentially affect transmission flows resulting in a SOL or IROL violation) is armed. The Reliability Plan shall document that the RELIABILITY COORDINATOR shall be informed of the status of the Special Protection System including any degradation or potential failure to operate as expected by the TRANSMISSION OPERATOR.

5. The Reliability Plan shall document the procedure the RELIABILITY COORDINATOR will use to issue an alert to all BALANCING AUTHORITIES and TRANSMISSION OPERATORS in its RELIABILITY COORDINATOR AREA, and all RELIABILITY COORDINATORS within the INTERCONNECTION via the Reliability Coordinator Information System when it foresees a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its RELIABILITY COORDINATOR AREA. The Reliability Plan shall document how the RELIABILITY COORDINATOR will disseminate this information to its BALANCING AUTHORITIES and TRANSMISSION OPERATORS. (Policy 9 Requirement E.1.5)

6. The Reliability Plan shall document the processes and procedures the RELIABILITY COORDINATOR uses to confirm reliability assessment results and to determine the effects within its own and adjacent RELIABILITY COORDINATOR AREAS. The Reliability Plan shall document the processes and procedures the RELIABILITY COORDINATOR will follow to derive and discuss options to mitigate potential or actual SOL or IROL violations and to identify and implement only those actions as necessary as to always act in the best interests of the INTERCONNECTION at all times. (Policy 9 Requirement E.1.6)

Comments

Roman Carter Marc Butts Southern	Section E. Current-Day Operations should provide the Reliability Coordinator the "Whats" that need to be included in the RC Reliability Plan. Each RC would then have the flexibility to provide the "Hows" on each requirement and show "how" the RC will fullfil them.
Travis Besier	Please explain or clarify the use of the term "inter-" in paragraph 4.11.

TXU Regu. Affairs	
Edward J. Davis Entergy	1. Please change the bold lead in section from ".. how it conducts current-day reliability analyses for … " to "…how it conducts current-day reliability analyses to meet NERC Standards for…". Delete the phrase "At a mimimum this documentation shall address the following:". 2. Delete all of items 1 through 6. The details in these items repeat the details enumerated in the Standards and are unnecessary. Additionally, if additional requirements are contained in the above they would inappropriately impose new requirements on the RC if they are included in this Template and not included in the Standard. Therefore the above should be deleted. 3. If desired, this section may contain a list of the titles of each of the NERC Standards that requires interaction between the RCs and each of the entities identified in each of the Standards. However, this section should not contain a detailed list of the Requirements contained in the Standards, nor should it contain a subset of those requirements.
Pete Henderson IESO Karl Tammar NYISO	See comments for item A. This lists requirements that should be in the standards & hence there is no need for them here. This template should only be a high level outline of what aspects the RC Plan should address.
Greg Tillitson CAISO WECC RCS	The template lists requirements that should be in the Standards; there is no need for them here. This template should only be a high level outline of what aspects the RC Plan should address.

F. Emergency Operations

The Reliability Plan shall document the processes and procedures the RELIABILITY COORDINATOR will follow to respond to BULK ELECTRIC SYSTEM alerts and emergencies within its RELIABILITY COORDINATOR AREA, and to alerts and emergencies originating in neighboring RELIABILITY COORDINATOR AREAS. At a minimum this documentation shall address the following:

1. The Reliability Plan shall document the process and procedures the RELIABILITY COORDINATOR uses to direct its BALANCING AUTHORITIES and TRANSMISSION OPERATORS to return the transmission system to within the IROL as soon as possible, but no longer than 30 minutes. The Reliability Plan shall document the actions (e.g. reconfiguration, redispatch or load shedding) the RELIABILITY COORDINATOR will direct until relief requested by the TLR process is achieved. (Policy 9 Requirement F.1)

2. The Reliability Plan shall document the processes and procedures the RELIABILITY COORDINATOR will implement when it deems that IROL violations are imminent. The Reliability Plan shall document the processes and procedures the RELIABILITY COORDINATOR shall follow when directing its BALANCING AUTHORITIES and TRANSMISSION OPERATORS to redispatch generation, reconfigure transmission, manage INTERCHANGE TRANSACTIONS, or reduce system demand to mitigate the IROL violation 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 Plan shall also document how the RELIABILITY COORDINATOR will coordinate its alert and emergency procedures with other RELIABILITY COORDINATORS. (Policy 9 Requirement F.2)

3. The Reliability Plan shall document the processes and procedures the RELIABILITY COORDINATOR will implement in the event the loading of transmission facilities progresses to or is projected to progress to a SOL or IROL violation. At a minimum, the Reliability Plan shall document how the RELIABILITY COORDINATOR will perform the following procedures as necessary (Policy 9 Requirement F.3):

    4.1. The Reliability Plan shall document the processes and procedures used to determine when the RELIABILITY COORDINATOR will implement a local (Regional, Interregional, or subregional) transmission loading relief procedure or an INTERCONNECTION-wide procedure for resolving a potential or actual SOL or IROL violation on the transmission system within its RELIABILITY COORDINATOR AREA.

    4.2. The Reliability Plan shall identify for each local transmission loading relief or congestion management procedure the TRANSMISSION OPERATORS to which the procedure applies.

    4.3. As appropriate, the Reliability Plan shall document how the RELIABILITY COORDINATOR will implement a local transmission loading relief or congestion management procedure simultaneously with an INTERCONNECTION-wide procedure.

    4.4. The Reliability Plan shall document how the RELIABILITY COORDINATOR will comply with the provisions of the INTERCONNECTION-wide procedure including action by RELIABILITY COORDINATORS in other INTERCONNECTIONS to, for example, curtail an INTERCHANGE TRANSACTION that crosses an INTERCONNECTION boundary.

    4.5. The Reliability Plan shall document the processes and procedures the RELIABILITY COORDINATOR will follow during the implementation of relief procedures, up to the point that emergency action is necessary.

4. The Reliability Plan shall document the processes and procedures the RELIABILITY COORDINATOR will implement when the INTERCONNECTION frequency error is in excess of 0.03 Hz (Eastern

INTERCONNECTION) or 0.05 Hz (Western and ERCOT INTERCONNECTIONS) for more than 20 minutes. The Reliability Plan shall document the processes and procedures the Reliability Coordinator will implement when it determines that one or more of its BALANCING AUTHORITIES is contributing to the frequency error. (Policy 9 Requirement F.4)

5. The Reliability Plan shall document the processes and procedures the RELIABILITY COORDINATOR will implement to mitigate an energy emergency within its RELIABILITY COORDINATOR AREA. The Reliability Plan shall document how the RELIABILITY COORDINATOR shall provide assistance to other RELIABILITY COORDINATORS experiencing an energy emergency in accordance with Appendix 5C, Subsection A, "Energy Emergency Alerts." (Policy 9 Requirement F.5)

6. The Reliability Plan shall document the processes and procedures the RELIABILITY COORDINATOR will implement when it is experiencing a potential or actual Energy Emergency within any BALANCING AUTHORITY, RESERVE-SHARING GROUP, or LOAD-SERVING ENTITY within its RELIABILITY COORDINATOR AREA. The Reliability Plan shall document the processes and procedures the RELIABILITY COORDINATOR will implement to mitigate the emergency condition, including a request for emergency assistance if required. (Policy 9 Requirement F.6)

Comments

Edward J. Davis Entergy	1. Please change the bold lead in section from ".. will follow to respond … " to " .. will follow to meet NERC Standards to respond … ". Delete the phrase "At a mimimum this documentation shall address the following:". 2. Delete all of items 1 through 6. The details in these items repeat the details enumerated in the Standards and are unnecessary. Additionally, if additional requirements are contained in the above they would inappropriately impose new requirements on the RC if they are included in this Template and are not included in the Standard. Therefore the above should be deleted. 3. If desired, this section may contain a list of the titles of each of the NERC Standards that requires interaction between the RCs and each of the entities identified in each of the Standards. However, this section should not contain a detailed list of the Requirements contained in the Standards, nor should it contain a subset of those requirements.
Pete Henderson IESO Karl Tammar NYISO	Again, this section seems to add some new specific requirements that should be in standards, which should not be permitted as the template does not go through the ANSI standard process. See comments for item A. This lists requirements that should be in the standards & hence there is no need for them here. This template should only be a high level outline of what aspects the RC Plan should address.
Greg Tillitson CAISO WECC RCS	The template lists requirements that should be in the Standards; there is no need for them here. This template should only be a high level outline of what aspects the RC Plan should address

G. System Restoration

The Reliability Plan shall document the processes and procedures the RELIABILITY COORDINATOR will follow to respond to BULK ELECTRIC SYSTEM outages originating within its RELIABILITY COORDINATOR AREA, and to BULK ELECTRIC SYSTEM outages originating in neighboring RELIABILITY COORDINATOR AREAS. At a minimum this documentation shall address the following:

1. The Reliability Plan shall document that the RELIABILITY COORDINATOR is knowledgeable of the restoration plan of each BALANCING AUTHORITY and TRANSMISSION OPERATOR in its RELIABILITY COORDINATOR AREA. The Reliability Plan shall document the RELIABILITY COORDINATOR'S role in monitoring the restoration progress and coordinating any needed assistance. (Policy 9 Requirement G.1)

2. The Reliability Plan shall document that the RELIABILITY COORDINATOR has a restoration plan for its RELIABILITY COORDINATOR AREA that provides coordination between individual BALANCING AUTHORITY and TRANSMISSION OPERATOR restoration plans and that ensures reliability is maintained during system restoration events. (Policy 9 Requirement G.2)

3. The Reliability Plan shall document the processes and procedures the RELIABILITY COORDINATOR will follow for disseminating information regarding restoration to neighboring RELIABILITY COORDINATORS and BALANCING AUTHORITIES or TRANSMISSION OPERATORS not immediately involved in restoration. (Policy 9 Requirement G.3)

Comments

Edward J. Davis Entergy	1. Please change the bold lead in section from "…will follow to respond … " to "…will follow to meet NERC Standards to respond…". Delete the phrase "At a minimum this documentation shall address the following:". 2. Delete all of items 1 through 3. The details in these items repeat the details enumerated in the Standards and are unnecessary. Additionally, if additional requirements are contained in the above they would inappropriately impose new requirements on the RC if they are included in this Template and are not included in the Standard. Therefore the above should be deleted. 3. If desired, this section may contain a list of the titles of each of the NERC Standards that requires interaction between the RCs and each of the entities identified in each of the Standards. However, this section should not contain a detailed list of the Requirements contained in the Standards, nor should it contain a subset of those requirements.
Pete Henderson IESO Karl Tammar NYISO	See comments for item A. This lists requirements that should be in the standards & hence there is no need for them here. This template should only be a high level outline of what aspects the RC Plan should address.
Greg Tillitson CAISO WECC RCS	The template lists requirements that should be in the Standards; there is no need for them here. This template should only be a high level outline of what aspects the RC Plan should address.

H. Coordination Agreements and Data Sharing

The Reliability Plan shall document that the RELIABILITY COORDINATOR has coordination agreements with adjacent RELIABILITY COORDINATORS to ensure that SOL or IROL violation mitigation requiring actions in adjacent RELIABILITY COORDINATOR AREAS are coordinated. At a minimum this documentation shall address the following:

The Reliability Plan shall document the data requirements to support the RELIABILITY COORDINATOR'S reliability coordination tasks, and the procedures to request such data from its BALANCING AUTHORITIES, INTERCHANGE AUTHORITIES, TRANSMISSION OWNERS, TRANSMISSION OPERATORS, GENERATION OWNERS, GENERATION OPERATORS, and LOAD-SERVING ENTITIES or adjacent RELIABILITY COORDINATORS, in accordance with the provisions of Policy 4, "System Coordination." (Policy 9 Requirement H.1, H.2, and H.3 and Policy 4 Requirement B.4)

Comments

Edward J. Davis Entergy	1. Please change the bold lead in section from ".. has coordination agreements with adjacent Reliability Coordinators to ensure that SOL or IROL violation mitigation requiring actions in adjacent Reliability Coordinator Areas are coordinated." to " .. has coordination and data sharing agreements with adjacent Reliability Coordinators to meet NERC Standards." Delete the phrase "At a mimimum this documentation shall address the following:". 2. Delete all of the second paragraph. 3. If desired, this section may contain a list of the titles of each of the NERC Standards that requires interaction between the RCs and each of the entities identified in each of the Standards. However, this section should not contain a detailed list of the Requirements contained in the Standards, nor should it contain a subset of those requirements.
Pete Henderson IESO Karl Tammar NYISO	See comments for item A. This lists requirements that should be in the standards & hence there is no need for them here. This template should only be a high level outline of what aspects the RC Plan should address.
Greg Tillitson CAISO WECC RCS	The template lists requirements that should be in the Standards; there is no need for them here. This template should only be a high level outline of what aspects the RC Plan should address.

I. Facility

The Reliability Plan shall document that the RELIABILITY COORDINATOR has the facilities to perform its responsibilities. At a minimum this documentation shall address the following:

1. The Reliability Plan shall document that the RELIABILITY COORDINATOR has adequate communications (voice and data links) to appropriate entities within its RELIABILITY COORDINATOR AREA, which are staffed and available to act in addressing a real time emergency condition. (Policy 9 Requirement I.1.1 and Policy 7 Requirement A.1)

2. The Reliability Plan shall document that the RELIABILITY COORDINATOR has multi-directional capabilities between it and its BALANCING AUTHORITIES and TRANSMISSION OPERATORS and also between it and its neighboring RELIABILITY COORDINATOR(S) for both voice and data exchange as required to meet reliability needs of the INTERCONNECTION. (Policy 9 Requirement I.1.2)

3. The Reliability Plan shall document that the RELIABILITY COORDINATOR has detailed real-time monitoring capability of its RELIABILITY COORDINATOR AREA and sufficient monitoring capability of surrounding RELIABILITY COORDINATOR AREAS to ensure that potential or actual SOL or IROL violations are identified. The Reliability Plan shall document that the RELIABILITY COORDINATOR has monitoring systems that provide information that can be easily understood and interpreted by the RELIABILITY COORDINATOR, giving particular emphasis to alarm management and awareness systems, automated data transfers, synchronized information systems, over a redundant and highly reliable infrastructure. (Policy 9 Requirement I.1.3)

    3.1. The Reliability Plan shall document that the RELIABILITY COORDINATOR monitors BULK ELECTRIC SYSTEM elements (generators, transmission lines, busses, transformers, breakers, etc.) that could result in SOL or IROL violations within its RELIABILITY COORDINATOR AREA. The Reliability Plan shall document that the RELIABILITY COORDINATOR monitors both real and reactive power system flows, OPERATING RESERVES, and the status of BULK ELECTRIC SYSTEM elements that are or could be critical to SOLs and IROLs and system restoration requirements within its RELIABILITY COORDINATOR AREA. (Policy 9 Requirement I.1.3.1)

4. Study and analysis tools. (Policy 9 Requirement I.1.4)

    4.1. The Reliability Plan shall document that the RELIABILITY COORDINATOR has adequate analysis tools such as State Estimation, pre- and post-CONTINGENCY analysis capabilities (thermal, stability, and voltage) and WIDE AREA overview displays.

    4.2. The Reliability Plan shall document that the RELIABILITY COORDINATOR continuously monitors its RELIABILITY COORDINATOR AREA. The Reliability Plan shall document that the RELIABILITY COORDINATOR has provisions for backup facilities that shall be exercised if the main monitoring system is unavailable. The Reliability Plan shall document how the RELIABILITY COORDINATOR will ensure that SOL and IROL monitoring and derivations will continue if the main monitoring system is unavailable.

    4.3. The Reliability Plan shall document the processes and procedures used by the RELIABILITY COORDINATOR to ensure control of its analysis tools, including approvals for planned maintenance. The Reliability Plan shall document that the RELIABILITY COORDINATOR has procedures in place to mitigate the affects of analysis tool outages.

Comments

Donald S. Watkins BPA	While firmly established as a goal, we expect that it will take several years for RCs to gain sufficient maturity to have “adequate” real time assessment as envisioned,

	particularly in the stability analysis area.
Roman Carter Marc Butts Southern	Under I. Facility- Subsection 3 should be reworded to make it clear that the RC is not responsible for monitoring the capabilities of surrounding Reliability Coordinators. It is believed the original intent was to require the RC to document its detailed real-time monitoring capability of its internal area (not external to that particular RC). Also, in the last sentence of 3., it requires the infrastructure of the RC's monitoring systems be "redundant". NERC is prescribing "how" the RC should provide its monitoring systems. As stated previously, NERC should be concerned with the "Whats" and leave the "Hows" to the RC. Taking away the RC's ability to determine the best way to accomplish the "whats" in section 3 will only stifle the RC's ability to optimize their systems. Under section 4.1, what is meant by adding "Stability" to the parenthetical statement "(thermal, stability, and voltage)? Most, if not all, RCs in the Eastern Interconnection do not have on-line stability analysis tools. They currently use "Static" limits for stability.
Travis Besier TXU Regu. Affairs	Please explain or clarify the term “multi-directional” as used in paragraph 2. For clarification, please change the second sentence of paragraph 3. to read: “The Reliability Plan shall document that the Reliability Coordinator has monitoring systems that provide information that can be easily understood and interpreted by the Reliability Coordinator **operators**, giving particular emphasis to alarm management and awareness systems, automated data transfers **and** synchronized information systems over a redundant and highly reliable **communication** infrastructure.” Please explain or clarify the term “derivations” as used in paragraph 4.2.
Edward J. Davis Entergy	1. Please change the bold lead in section from ".. has coordination agreements with adjacent Reliability Coordinators to ensure that SOL or IROL violation mitigation requiring actions in adjacent Reliability Coordinator Areas are coordinated." to " .. has coordination and data sharing agreements with adjacent Reliability Coordinators to meet NERC Standards." Delete the phrase "At a mimimum this documentation shall address the following:". 2. Delete all of the second paragraph. 3. If desired, this section may contain a list of the titles of each of the NERC Standards that requires interaction between the RCs and each of the entities identified in each of the Standards. However, this section should not contain a detailed list of the Requirements contained in the Standards, nor should it contain a subset of those requirements.
Pete Henderson IESO Karl Tammar NYISO	See comments for item A. This lists requirements that should be in the standards & hence there is no need for them here. This template should only be a high level outline of what aspects the RC Plan should address.
Greg Tillitson CAISO WECC RCS	The template lists requirements that should be in the Standards; there is no need for them here. This template should only be a high level outline of what aspects the RC Plan should address.

J. Staffing

The Reliability Plan shall document that the RELIABILITY COORDINATOR has adequate staff and facilities. At a minimum this documentation shall address the following:

1. The Reliability Plan shall document that the RELIABILITY COORDINATOR is staffed with adequately trained and NERC or in the alternative, Interconnection wide Regional Reliability Organization - Certified RELIABILITY COORDINATOR operators, 24 hours/day, seven days/week. The Reliability Plan shall document that the RELIABILITY COORDINATOR requires its RELIABILITY COORDINATOR operators to complete a minimum of five days per year of training and drills using realistic simulations of system emergencies, in addition to other training required to maintain qualified operating personnel. (Policy 9 Requirement J.1.1 and Policy 8 Requirements B.1 and C.1)

2. The Reliability Plan shall document how the RELIABILITY COORDINATOR ensures that its RELIABILITY COORDINATOR operators have a comprehensive understanding of its RELIABILITY COORDINATOR AREA and interaction with neighboring RELIABILITY COORDINATOR AREAS. The Reliability Plan shall document that the RELIABILITY COORDINATOR operators have an extensive understanding of the BALANCING AUTHORITIES, TRANSMISSION OPERATORS, and GENERATION OPERATORS within its RELIABILITY COORDINATOR AREA, such as staff, operating practices and procedures, restoration priorities and objectives, outage plans, equipment capabilities and restrictions. The Reliability Plan shall document the protocols that are in place to ensure that the RELIABILITY COORDINATOR has the best available information at all times. (Policy 9 Requirement J.1.2 and Policy 4 Requirement A.3)

3. **Standards of Conduct**. The Reliability Plan shall document that the entity responsible for the RELIABILITY COORDINATOR function has signed and will adhere to the NERC or in the alternative, an Interconnection wide Regional Reliability Organization RELIABILITY COORDINATOR Standards of Conduct. (Policy 9 Requirement J.1.3)

Comments

Roman Carter Marc Butts Southern	Under J. Staffing - Section 2 states the RC have an "extensive understanding" of the BAs, TOPs, and GOPs within its area. This is ambiguous and should be limited to being a NERC certified System Operator or some other type of tangible training and testing.
Edward J. Davis Entergy	1. Please change the bold lead in section from ".. adequate staff and facilities." to " .. adequate staff and facilities to meet NERC Standards.". Delete the phrase "At a mimimum this documentation shall address the following:". 2. Delete all of items 1 through 3. The details in these items repeat the details enumerated in the Standards and are unnecessary. Additionally, if additional requirements are contained in the above they would inappropriately impose new requirements on the RC if they they are included in this Template and not included in the Standard. Therefore the above should be deleted. 3. If desired, this section may contain a list of the titles of each of the NERC Standards that requires interaction between the RCs and each of the entities identified in each of the Standards, e.g., PER-004 - Reliability Coordination - Staffing. However, this section should not contain a detailed list of the Requirements contained in the Standards, nor should it contain a subset of those requirements.
Pete Henderson IESO	See comments for item A. This lists requirements that should be in the standards & hence there is no need for them here. This template should only be a high level

Karl Tammar NYISO	outline of what aspects the RC Plan should address.
Greg Tillitson CAISO WECC RCS	The template lists requirements that should be in the Standards; there is no need for them here. This template should only be a high level outline of what aspects the RC Plan should address.

Template for Developing a Balancing Authority Integrated Operational Plan

Draft 3

Integrated Operational Plan Subsections

A. Real Power Balancing Control Performance
B. Disturbance Control Performance
C. Frequency Response and Bias
D. Time Error Correction
E. Automatic Generation Control
F. Inadvertent Interchange
G. Voltage and Reactive Control
H. Interchange Transactions
I. Monitoring System Conditions
J. Providing Operating Reliability Information
K. Planned Outage Coordination
L. System Protection Coordination
M. Reliability Responsibilities and Authorities
N. Communications and Coordination
O. Emergency Operations
P. Disturbance and Sabotage Reporting
Q. Operations Planning
R. Plans for Loss of Control Center Functionality
S. Telecommunications
T. Operating Personnel

Introduction

This document outlines the requirements that a BALANCING AUTHORITY shall address in its Integrated Operational Plan.

Initial Balancing Authority's Integrated Operational Plan

A BALANCING AUTHORITY shall prepare an Integrated Operational Plan that documents that it has the processes, procedures, tools, and agreements in place to perform the reliability functions and responsibilities assigned to the BALANCING AUTHORITY in the Operating Policies or the successor Version 0 Reliability Standards. The initial Integrated Operational Plan will outline the metered boundaries of its BALANCING AUTHORITY AREA and shall identify each GENERATION OWNER, TRANSMISSION OWNER, and LOAD SERVING ENTITY within those metered boundaries.

Approval Process for Changes to a Balancing Authority's Area

Changes to a BALANCING AUTHORITY'S AREA boundary must be:

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

2. Accompanied by an update of all impacted Regional Council's Regional Operating Reliability Plan to reflect the BALANCING AUTHORITY'S AREA within the Regional Council's purview.

3. Submitted to NERC by the impacted Regional Councils for posting.

Balancing Authority's Integrated Operational Plan Approval Process

The BALANCING AUTHORITY shall submit its initial or revised Integrated Operational Plan to all Regional Reliability Councils, within which the BALANCING AUTHORITY will operate.

Balancing Authority Audits

The BALANCING AUTHORITY shall be audited at the direction of the NERC Vice President of Compliance prior to implementing its initial Integrated Operational Plan, and on a periodic basis thereafter as determined by the NERC Board of Trustees.

The BALANCING AUTHORITY may be audited at the direction of the NERC Vice President of Compliance when any of the following events occurs within a BALANCING AUTHORITY'S AREA:

1. A change in the BALANCING AUTHORITY'S membership resulting in a change in the BALANCING AUTHORITY'S AREA.
2. A change in scope within the BALANCING AUTHORITY'S AREA, e.g. the start-up of a market operation.

Comments

Roman Carter Southern	Very soon NERC will no longer be depending on Operating Policy for reliability. NERC will rely on the Version 0 Standards to be adopted by the Board in February as the primary source for meeting the reliability requirements of the Bulk Electric System. As such, Southern Company Generation recommends that the Balancing Authority's Integrated Operational Plan should remove references to Operating Policy and replace them with Version 0 Standards. This guide for Developing a NERC Balancing Authority Integrated Operational Plan should not be confused with Planning Templates or Compliance Templates and therefore should be referred to as a "Guide or Reference Document" to make a clear distinction between the NERC Templates and this Guide.
Edward J. Davis Entergy	We have several overall comments on this document and then several specific comments on this section. A. OVERALL COMMENTS 1. Delete all references to Operating Policies and successor Version 0 Realibility Standards. While this terminology was previously appropriate it is no longer appropriate since NERC will have Board approved Standards long before this standard is approved. 2. Therefore, add to the introductory table of contents and to each appropriate place in the text the specific new NERC Standards numbers to which the BA Integrated Operational Plan (IOP) should conform. 3. We strongly recommend deleting from this Template the details of what should be contained in an IOP and that are already contained in the Standards. While this approach may have been appropriate at the time, it is no longer appropriate since NERC will have Board approved Standards long before this standard is approved. In general, most of the text of this Template consists of re-iteration of the NERC Operating Policies, or the new NERC Standards. There is no need to do that re-iteration as the details are in the Standards to which the entity should conform.

	B. SPECIFIC COMMENTS ON THIS SECTION 4. This section should be entitled "A1. Integrated Operational Plan Approval Process and Approval Requirements" and a new title added to the table of contents. This section specifies and details the requirements that a BA develop an IOP, what is to be done with that required IOP, and what entities "endorse" the IOP. Everything else in this Template specifies what must be in the IOP. 5. Add to the "Introduction" the following statement: "This section outlines the endorsement process the industry will use to have that IOP reviewed and endorsed." 6. Delete "Initial" from the title "Initial Balancing Authority's Integrated Operational Plan". 7. Revise the third line of the "Initial Balancing Authority's Integrated Operational Plan" by replacing the phrase " … in the Operating Policies or the successor Version 0 Reliability Standards." with the phrase " … in the NERC Standards". 8. Delete the section "Approval Process for Changes to a Balancing Authority's Area" and change section "Balancing Authority's Integrated Operational Plan Approval Process" as detailed in number 9 below. 9. Add to the end of the existing section "Balancing Authority's Integrated Operational Plan Approval Process" as follows: "The new or revised Integrated Operational Plan shall be reviewed by the applicable NERC Regional Reliability Councils and endorsed by those Councils when the IOP meets the requirements of the NERC Standards. The RRO shall add this endorsed IOP to its Regional Operating Reliability Plan and submit that Regional Plan to NERC for posting on its website." 10. Does any entity "endorse" the initial IOP? It is not apparent in the existing wording. 11. In the section "Balancing Authority Audits" replace "A change in the Balancing Authority's membership .. " with "A change in the Balancing Authority's metered boundaries, or Generation Owner, Transmission Owner, or Load Serving Entity within those meterd boundaries …." 12. Please give more details about what constitutes a "change in scope" within the BAs Area. The given statement is too vague in general and absolutely too vague for a Standard, to understand what is meant by that phrase.
Kenneth A. Goldsmith Alliant	NERC is asking Reliability Regions, Balancing Authorities and Reliability Coordinators to doucment processes and procedures in multiple areas and there does not seem to be any standardization. There needs to be some consistency across the industry. Which Drafting Team developed this template? Was it done by NERC staff and not the industry? Will there be a requirement to have all of the information in one document, or will it be acceptable to have it located in multiple documents?
Alan Boesch NPPD	Will the audit be based on the version 0 standards or this document? The requirements in this document do not match the version 0 standards.

	General comment: It appears that whoever put this document together did a wholesale replacement of the Control Area with the BA. Part of the reason for the function model was the distribution of functions (TOP, BA, Generation Operator, LSE) to different entities. This document does not recognize that capability and is inconsistent with the version 0 standards. Also the term Integrated Operational Plan is used in the functional model and has been identified and defined in the Balancing Authority Certification Standard. This document is inconsistent with the definition of an Integrated Operational Plan.
Pete Henderson IESO Karl Tammar NYISO	It is not clear why a change in membership should result in an audit.
Thomas V. Pruitt Duke	This comment applies to all sections of this document and the RC Plan Template as well. The document should be reformatted to be consistent with the new Version 0 standards (i.e., the organization and order should match the structure of the Version 0 standards -- all TOP standard related topics together and in numerical order, and so on). This comment also applies to all sections of this document and the RC Plan Template as well. All references to current Operating Policy should be changed to the corresponding Version 0 standards. Translation to Version 0 needs to occur as soon as possible to minimize the work currently underway by several entitites to rewrite their plans.

A. Real Power Balancing Control Performance

The BALANCING AUTHORITY shall provide documentation within its Integrated Operational Plan that it has the processes and procedures in place to meet Real Power Balancing Control Performance standards.

1. The BALANCING AUTHORITY shall document the processes and procedures used to ensure operations such that, on a rolling 12-month basis, the average of the clock-minute averages of the BALANCING AUTHORITY AREA's ACE divided by 10B (B is the clock-minute average of the BALANCING AUTHORITY AREA's frequency bias) times the corresponding clock-minute averages of the INTERCONNECTION's FREQUENCY ERROR is less than a specific limit. (Policy 1 Requirement A.1.1)

2. The BALANCING AUTHORITY shall document the processes and procedures used to ensure operations such that its average ACE for at least 90% of clock-ten-minute periods (6 non-overlapping periods per hour) during a calendar month is within a specific limit, referred to as L_{10}. (Policy 1 Requirement A.1.2)

3. A BALANCING AUTHORITY providing OVERLAP REGULATION SERVICE shall document the processes and procedures used to evaluate Policy 1 Requirement A.1.1 (CPM1) and Policy 1 Requirement A.1.2 (CPM2) using the characteristics of the combined ACE and combined FREQUENCY BIAS SETTINGS. (Policy 1 Requirement A.2.2)

4. If a BALANCING AUTHORITY is receiving OVERLAP REGULATION SERVICE it shall document the BALANCING AUTHORITY from which it is receiving the OVERLAP REGULATION SERVICE.

Comments

Edward J. Davis Entergy	1. Please change the bold lead in section from "…to meet Real Power Balancing Control Performance standards." to "…to meet NERC Standard BAL-001 Real Balancing Control Performance." 2. Delete all of items 1 through 4. The details in these items repeat the details enumerated in the Standards and are unnecessary. Additionally, if additional requirements are contained in the above they would inappropriately impose new requirements on the BA if they are included in this Template and not included in the Standard. Therefore the above should be deleted.
Alan Boesch NPPD	These requirements refer to policy and should refer to version 0 standards. The requirement for documentation of processes and procedures for CPM1 and 2 is not necessary and beyond the requirements of the version 0 standards. Any review of the BA should be based on the version 0 requirements and should not add any additional requirements.
Pete Henderson IESO Karl Tammar NYISO	This template should provide only an outline or Table Of Contents of what is expected to be covered by the Plan as a guide for the developers of the Plan. It should not list requirements for the BA, as these should be covered by the soon to be implemented Version 0 standards. Templates approved outside the Standard Process create the potential of having inconsistent requirements or of adding new requirements that are not part of the standards. The document should provide the timelines for implementation of this template and provide NERC's expectations of Reliability Coordinators to evolve existing RC plans to this format.

	Furthermore, it would appear that some of these tasks may overlap with the TOp or RC(RA) tasks.

B. Disturbance Control Performance

The BALANCING AUTHORITY shall provide documentation within its Integrated Operational Plan that it has the processes and procedures in place to meet Disturbance Control Performance standards.

1. The BALANCING AUTHORITY shall document that it has access to and/or operates CONTINGENCY RESERVES to respond to disturbances. (Policy 1 Requirement B.1)

2. The BALANCING AUTHORITY shall document the processes and procedures it uses to activate sufficient CONTINGENCY RESERVE to comply with the Disturbance Control Performance Measure. (Policy 1 Requirement B.2)

3. The BALANCING AUTHORITY shall document the processes and procedures used to fully restore its CONTINGENCY RESERVES within the CONTINGENCY RESERVE RESTORATION PERIOD for its INTERCONNECTION. The CONTINGENCY RESERVE RESTORATION PERIOD begins at the end of the DISTURBANCE RECOVERY PERIOD. (Policy 1 Requirement B.3)

Comments

Edward J. Davis Entergy	1. Please change the bold lead in section from "…to meet Disturbance Control Performance standards." to "…to meet NERC Standard BAL-002 Disturbance Control Performance." 2. Delete all of items 1 through 3. The details in these items repeat the details enumerated in the Standards and are unnecessary. Additionally, if additional requirements are contained in the above they would inappropriately impose new requirements on the BA if they are contained in this Template and are not included in the Standard. Therefore the above should be deleted.
Alan Boesch NPPD	DOCUMENTATION of the access to, actvation and restoration of reserves to meeting DCS requirements is beyond the requirements of the version 0 standards. Any review of the BA should be based on the version 0 requirements and should not add any additional requirements.
Pete Henderson IESO Karl Tammar NYISO	See comments in first paragraph of the comments for A.

C. Frequency Response and Bias

The BALANCING AUTHORITY shall provide documentation within its Integrated Operational Plan that it has the processes and procedures in place to meet Frequency Response and Bias standards.

1. The BALANCING AUTHORITY shall document the processes and procedures used to determine its frequency response characteristic. (Policy 1 Requirement C.1)

2. The BALANCING AUTHORITY shall document the processes and procedures used to ensure that it operates its AGC on tie-line frequency bias, unless such operation is adverse to system or INTERCONNECTION reliability. (Policy 1 Standard C.1)

3. If the BALANCING AUTHORITY uses Dynamic Scheduling or Pseudo- ties for jointly owned units, it shall document the processes and procedures used to ensure that its respective share of the unit governor droop response is reflected in its Frequency Bias Setting. (Policy 1 Standard C.1.1.3)

4. If the BALANCING AUTHORITY serves native load, it shall document that it has a monthly average Frequency Bias Setting that is at least 1% of its estimated yearly peak demand per 0.1 Hz change. If the BALANCING AUTHORITY does not serve native load, it shall document that it has a monthly average Frequency Bias Setting that is at least 1% of its estimated maximum generation level in the coming year per 0.1 Hz change. (Policy 1 Standard C.1.1.4 and C.1.1.5)

If the BALANCING AUTHORITY is performing OVERLAP REGULATION SERVICE, it shall document that it has increased its Frequency Bias Setting to match the frequency response of the entire area being controlled. (Policy 1 Standard C.1.1.6)

Comments

Edward J. Davis Entergy	1. Please change the bold lead in section from "…to meet Frequency Response and Bias standards." to "…to meet NERC Standard BAL-003 Frequency Response and Bias." 2. Delete all of items 1 through 4 and the last paragraph. The details in these items repeat the details enumerated in the Standards and are unnecessary. Additionally, if additional requirements are contained in the above they would inappropriately impose new requirements on the BA if they are in included in this Template and are not included in the Standard. Therefore the above should be deleted.
Alan Boesch NPPD	DOCUMENTATION is beyond the requirements of the version 0 standards. Any review of the BA should be based on the version 0 requirements and should not add any additional requirements. It would be more effective to review the tools it uses to implement Frequency Response and implement the BIAS setting.
Pete Henderson IESO Karl Tammar NYISO	See comments in first paragraph of the comments for A.

D. Time Error Correction

The BALANCING AUTHORITY shall provide documentation within its Integrated Operational Plan that it has the processes and procedures in place to meet Time Error Correction standards.

The BALANCING AUTHORITY shall document the procedures it shall follow when it identifies reliability concerns with the execution of a time error correction. (Policy 1 Requirement D.4)

Comments

Edward J. Davis Entergy	1. Please change the bold lead in section from "…to meet Time Error Correction standards." to "…to meet NERC Standard BAL-004 Time Error Correction." 2. Delete all of the unbolded sentence. The detail in this item repeats the detail enumerated in the Standard and is unnecessary. Additionally, if additional requirements are contained in the above they would inappropriately impose new requirements on the BA if they are included in this Template and are not included in the Standard. Therefore the above should be deleted.
Alan Boesch NPPD	DOCUMENTATION is beyond the requirements of the version 0 standards. Any review of the BA should be based on the version 0 requirements and should not add any additional requirements. It would be more effective to review the tools it uses to implement Time Error Coorection.
Pete Henderson IESO Karl Tammar NYISO	See comments in first paragraph of the comments for A.

E. Automatic Generation Control

The BALANCING AUTHORITY shall provide documentation within its Integrated Operational Plan that it has the processes and procedures in place to meet Automatic Generation Control standards.

1. The BALANCING AUTHORITY shall document the processes and procedures used to ensure that it maintains regulating reserves that can be controlled by AGC to meet the Control Performance Measure. (Policy 1 Requirement E.2.1)

2. If the BALANCING AUTHORITY is providing regulation service, it shall document that it has adequate metering, communications and control equipment employed to prevent such service from becoming a BURDEN on the INTERCONNECTION or other BALANCING AUTHORITY AREAS. (Policy 1 Requirement E.2.2.1)

3. If the BALANCING AUTHORITY is providing regulation service, it shall document the procedure used to notify the host BALANCING AUTHORITY for whom it is controlling if it is unable to provide the service, as well as any intermediary BALANCING AUTHORITIES. (Policy 1 Requirement E.2.2.2)

4. If the BALANCING AUTHORITY is receiving regulation service, it shall document the backup plans in place to provide replacement regulation service should the supplying BALANCING AUTHORITY no longer be able to provide this service. (Policy 1 Requirement E.2.2.3)

5. If the BALANCING AUTHORITY is operating asynchronously, it shall document the processes and procedures used to employ alternative ACE calculations such as (but not limited to) flat frequency control. (Policy 1 Requirement E.3.1)

6. The Balancing Authority shall document the procedure used to notify its RELIABILITY COORDINATOR in the event it is unable to calculate ACE for more than 30 minutes. (Policy 1 Requirement E.3.1)

7. The Balancing Authority shall document the procedures used to ensure continuous operation of AGC unless such operation adversely impacts the reliability of the Interconnection. (Policy 1 Requirement E.3.2) These procedures shall also address actions to be taken in the event AGC becomes inoperative, including the use of use of manual control to adjust generation to maintain the Net scheduled Interchange. (Policy 1 Requirement E.3.3)

8. The BALANCING AUTHORITY shall document the processes and procedures used to ensure that data-acquisition for and calculation of ACE occurs at least every six seconds. (Policy 1 Requirement E.4.1)

9. The BALANCING AUTHORITY shall document the provision of redundant and independent frequency metering equipment that shall automatically activate upon detection of failure of the primary source. (Policy 1 Requirement E.4.2)

10. The BALANCING AUTHORITY shall document the processes and procedures used to ensure the inclusion of all INTERCHANGE SCHEDULES with ADJACENT BALANCING AUTHORITIES in the calculation of Net Scheduled Interchange for the Area Control Error (ACE) equation. (Policy 1 Requirement E.4.3.1)

11. If the BALANCING AUTHORITY has an HVDC link to another BALANCING AUTHORITY connected asynchronously to their INTERCONNECTION, it shall document how it will consider the INTERCHANGE SCHEDULE related to the HVDC link in its ACE equation. (Policy 1 Requirement E.4.3.1.1)

12. The BALANCING AUTHORITY shall document the process and procedures used to ensure the inclusion of all Dynamic Schedules in the calculation of Net Scheduled Interchange for the ACE equation. (Policy 1 Requirement E.4.3.2)

13. The BALANCING AUTHORITY shall document the procedures used to ensure that agreed upon ramp rates are used in the Scheduled Interchange values to calculate ACE. (Policy 1 Requirement E.4.3.3)

14. The BALANCING AUTHORITY shall document the processes and procedures used to determine Actual Net Interchange. These processes and procedures shall address:

    14.1. The inclusion of all tie-line flows with ADJACENT BALANCING AUTHORITY Areas in the ACE calculation. (Policy 1 Requirement E.4.4.1)

    14.2. BALANCING AUTHORITIES that share a tie shall ensure tie line MW metering is telemetered to both control centers, and emanates from a common, agreed-upon source using common primary metering equipment. (Policy 1 Requirement E.4.4.2)

    14.3. BALANCING AUTHORITIES shall ensure that MWh data is telemetered or reported at the end of each hour. (Policy 1 Requirement E.4.4.2)

    14.4. BALANCING AUTHORITIES shall ensure the power flow and ACE signals that are utilized for calculating BALANCING AUTHORITY performance or that are transmitted for regulation service are not filtered prior to transmission, except for anti-aliasing filtering of tie lines. (Policy 1 Requirement E.4.4.3)

    14.5. BALANCING AUTHORITIES shall install common metering equipment where Dynamic Schedules or Pseudo-Ties are implemented between two or more BALANCING AUTHORITIES to deliver the output of Jointly Owned Units or to serve remote load. (Policy 1 Requirement E.4.4.4)

15. The BALANCING AUTHORITY shall document the processes and procedures used to ensure the performance of hourly error checks using tie-line MWh meters with common time synchronization to determine the accuracy of its control equipment. (Policy 1 Requirement E.4.5.1)

16. The BALANCING AUTHORITY shall document the processes and procedures used to adjust the component (e.g., tie-line meter) of ACE that is in error (if known) or use the interchange meter error (IME) term of the ACE equation to compensate for any equipment error until repairs can be made. (Policy 1 Requirement E.4.5.2)

17. The BALANCING AUTHORITY shall document the instrumentation and data recording equipment provided to its operating personnel to facilitate monitoring of control performance, generation response, and after-the-fact analysis of area performance. (Policy 1 Requirement E.4.6.1)

18. The BALANCING AUTHORITY shall document the provision of backup power supplies and the procedures to be followed to periodically test these supplies at its control center and other critical locations to ensure continuous operation of AGC and vital data recording equipment during loss of the normal power supply. (Policy 1 Requirement E.4.6.2)

Comments

Edward J. Davis Entergy	1. Please change the bold lead in section from "…to meet Automatic Generation Control s"

	2. Delete all of items 1 through 18. The details in these items repeat the details enumerated in the Standards and are unnecessary. Additionally, if additional requirements are contained in the above they would inappropriately impose new requirements on the BA if they are included in this Template and not included in the Standard. Therefore the above should be deleted.
Alan Boesch NPPD	DOCUMENTATION is beyond the requirements of the version 0 standards. Any review of the BA should be based on the version 0 requirements and should not add any additional requirements. It would be more effective to review the tools it uses to implement AGC.
Pete Henderson IESO Karl Tammar NYISO	See comments in first paragraph of the comments for A.

F. Inadvertent Interchange

The BALANCING AUTHORITY shall provide documentation within its Integrated Operational Plan that it has the processes and procedures in place to meet Inadvertent Interchange standards.

1. The BALANCING AUTHORITY shall document the processes and procedures used to calculate and record hourly INADVERTENT INTERCHANGE. (Policy 1 Standard F.1)

2. The BALANCING AUTHORITY shall document the processes and procedures used to ensure the inclusion of all AC tie lines that connect to its ADJACENT BALANCING AUTHORITY AREAS in its INADVERTENT INTERCHANGE account. The BALANCING AUTHORITY shall also document the processes and procedures used to take into account interchange served by jointly owned generators. (Policy 1 Standard F.2)

3. The BALANCING AUTHORITY shall document the processes and procedures used to ensure that all of its BALANCING AUTHORITY AREA interconnection points are equipped with common MWh meters, with readings provided hourly to the control centers of ADJACENT BALANCING AUTHORITIES. (Policy 1 Standard F.3)

4. The BALANCING AUTHORITY shall document the processes and procedures used to ensure that it operates to a common NET INTERCHANGE SCHEDULE and ACTUAL NET INTERCHANGE value with ADJACENT BALANCING AUTHORITY AREAS and that it records these hourly quantities, with like values but opposite sign. The BALANCING AUTHORITY shall also document the processes and procedures used to ensure the computation of its INADVERTENT INTERCHANGE based on the following (Policy 1 Standard F.4):

   4.1. That the BALANCING AUTHORITY, by the end of the next business day, agrees with its ADJACENT BALANCING AUTHORITIES to (Policy 1 Standard F.4.1):

      4.1.1. The hourly values of NET INTERCHANGE SCHEDULE (Policy 1 Standard F.4.1.1).

      4.1.2. The hourly integrated MWh values of NET ACTUAL INTERCHANGE (Policy 1 Standard F.4.1.2).

   4.2. That the BALANCING AUTHORITY uses 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 (Policy 1 Standard F.4.2).

   4.3. That the BALANCING AUTHORITY makes after-the-fact corrections to the agreed to daily and monthly accounting data only as needed 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 BALANCING AUTHORITY's INADVERTENT INTERCHANGE. After-the-fact corrections to scheduled or actual values will not be accepted without agreement of the ADJACENT BALANCING AUTHORITY(s) (Policy 1 Standard F.4.3).

Comments

Travis Besier TXU Regu. Affairs	Please explain or clarify "Changes or corrections based on non-reliability considerations…" as it appears in 4.3.
Edward J. Davis Entergy	1. Please change the bold lead in section from "…to meet Inadvertent Interchange standards." to "to meet NERC Standard BAL-006 Indavertent Interchange." 2. Delete all of items 1 through 4. The details in these items repeat the details

	enumerated in the Standards and are unnecessary. Additionally, if additional requirements are contained in the above they would inappropriately impose new requirements on the BA if they are included in this Template and not included in the Standard. Therefore the above should be deleted.
Alan Boesch NPPD	DOCUMENTATION is beyond the requirements of the version 0 standards. Any review of the BA should be based on the version 0 requirements and should not add any additional requirements. It would be more effective and consistent with the requirements of the version 0 standards to demonstrate the processes and tools it uses for determination of inadvertent.
Pete Henderson IESO Karl Tammar NYISO	See comments in first paragraph of the comments for A.

G. Voltage and Reactive Control

The BALANCING AUTHORITY shall provide documentation within its Integrated Operational Plan that it has the processes and procedures in place to meet Voltage and Reactive Control standards.

1. The BALANCING AUTHORITY shall document the processes and procedures used to ensure the provision of reactive resources to satisfy its reactive requirements. (Policy 2 Requirement B.2)

2. The BALANCING AUTHORITY shall document the processes and procedures used to take corrective action, including load reduction, necessary to prevent voltage collapse when reactive resources are insufficient. (Policy 2 Requirement B.5)

Comments

Edward J. Davis Entergy	Please change the bold lead in section from "…to meet Voltage and Reactive Control standards." to "…to meet NERC Standard VAR-001 Voltage and Reactive Control." Delete all of items 1 through 2. The details in these items repeat the details enumerated in the Standards and are unnecessary. Additionally, if additional requirements are contained in the above they would inappropriately impose new requirements on the BA if they are included in this Template and not included in the Standard. Therefore the above should be deleted.
Alan Boesch NPPD	The version 0 standards assigs the responsibility of Votage and Reactive Control to the Transmission Operator. Please delete this to be consistent with the version 0 standards.
Pete Henderson IESO Karl Tammar NYISO	See comments in first paragraph of the comments for A. This may overlap with the tasks of the TOp &/or RA.

H. Interchange Transactions

The BALANCING AUTHORITY shall provide documentation within its Integrated Operational Plan that it has the processes and procedures in place to meet Interchange Transaction 1) Tagging, 2) Tag Communication and Reliability Assessment, 3) Implementation, and 4) Modification standards.

1. Interchange Transaction Tagging

    1.1. The BALANCING AUTHORITY shall document the processes and procedures used to ensure the tagging of all INTERCHANGE TRANSACTIONS established to replace unexpected generation loss, such as through prearranged reserve sharing agreements or other arrangements, and all emergency transactions to mitigate SOL or IROL violations that sink within its BALANCING AUTHORITY AREA. (Policy 3 Requirement A.2.4.1)

    1.2. The BALANCING AUTHORITY shall document the processes and procedures used to ensure the tagging of all Bilateral Inadvertent Interchange Payback sinking within its BALANCING AUTHORITY AREA. (Policy 3 Requirement A.2.4.1)

    1.3. The BALANCING AUTHORITY shall document the processes and procedures used to ensure the submission of all tags to the SINK BALANCING AUTHORITY in accordance with NERC timing standards. (Policy 3 Requirement A.2.4)

2. Interchange Transaction Tag Communication and Reliability Assessment

    2.1. The BALANCING AUTHORITY shall document the processes and procedures used to ensure that all tags and any modifications to tags are provided to the appropriate entities for reliability assessment. (Policy 3 Requirement A.2.2)

    2.2. The BALANCING AUTHORITY shall document the processes and procedures used for assessing and approving or denying INTERCHANGE TRANSACTIONS. (Policy 3 Requirement A.4)

    2.3. The BALANCING AUTHORITY shall document the processes and procedures used for communicating its approval or denial of INTERCHANGE TRANSACTIONS to SINK BALANCING AUTHORITIES. (Policy 3 Requirement A.5)

    2.4. The BALANCING AUTHORITY shall document the processes and procedures used to communicate the composite approval status of INTERCHANGE TRANSACTIONS to PURCHASING-SELLING ENTITIES and all other BALANCING AUTHORITIES, TRANSMISSION SERVICE PROVIDERS and RELIABILITY AUTHORITIES on the scheduling path, upon receipt of approvals or denials from all of the individual BALANCING AUTHORITIES and TRANSMISSION SERVICE PROVIDERS. (Policy 3 Requirements A.5 and B.3)

3. Interchange Transaction Implementation

    3.1. The BALANCING AUTHORITY shall document the processes and procedures used to confirm INTERCHANGE SCHEDULES with a SENDING BALANCING AUTHORITY prior to implementation in its AREA CONTROL ERROR (ACE) equation or in the system that calculates its AREA CONTROL ERROR equation. (Policy 3 Requirement B.4)

    3.2. The BALANCING AUTHORITY shall document the processes and procedures used to ensure the implementation of INTERCHANGE SCHEDULES only with ADJACENT BALANCING AUTHORITIES. (Policy 3 Requirement B.1)

    3.3. The BALANCING AUTHORITY shall document the processes and procedures used to ensure the implementation of each INTERCHANGE TRANSACTION as tagged if it is the SINKING BALANCING AUTHORITY. (Policy 3 Requirement B.4)

4. Interchange Transaction Modification

4.1. The BALANCING AUTHORITY shall document the processes and procedures used to modify an INTERCHANGE TRANSACTION due to loss of generation, loss of load, or a TLR event (or other regional congestion management practices) by setting a new limit on the INTERCHANGE TRANSACTION tag that is in progress or scheduled to start and communicating this new limit to the SINK BALANCING AUTHORITY. (Policy 3 Requirement D.2)

4.2. The BALANCING AUTHORITY shall document the processes and procedures used to modify an INTERCHANGE TRANSACTION in accordance with NERC timing standards. (Policy 3 Requirement D.1)

Comments

Edward J. Davis Entergy	1. Please change the bold lead in section from "…to meet Interchange Transaction 1) Tagging, 2) Tag Communications and Reliablity Assessment, 3) Implementations, and 4) Modifications standards." to "…to meet NERC Standards INT-001 Interchange Transaction Tagging, INT-002 Interchange Transaction Tag Communication and Assessment, INT-003 Interchange Transaction Implementation, and INT-004 Interchange Transaction Modifications." 2. Delete all of items 1 through 4. The details in these items repeat the details enumerated in the Standards and are unnecessary. Additionally, if additional requirements are contained in the above they would inappropriately impose new requirements on the BA if they are included in this Template and not included in the Standard. Therefore the above should be deleted.
Alan Boesch NPPD	Schedules for loss of generation is exempt from tagging for the first 60 minutes. The BA is responsible for tagging and modifing tags for a small subset of schedules. Please modify the requirements to be consistent with the version 0 requirements. Documentation is beyond the requirements of the version 0 standards. A better approach that is consistent with the requirements of the version 0 standards is to demonstrate the processes and tools it uses for assessing, approving and modifing tags.
Pete Henderson IESO Karl Tammar NYISO	See comments in first paragraph of the comments for A. Also, this appears to overlap with the IA function. Is this an intended stopgap until the IA function is implemented?

I. Monitoring System Conditions

The BALANCING AUTHORITY shall provide documentation within its Integrated Operational Plan that it has the processes and procedures in place to monitor system conditions in accordance with NERC standards.

1. The BALANCING AUTHORITY shall document the processes and procedures used to inform its RELIABILITY COORDINATOR and other affected BALANCING AUTHORITIES and TRANSMISSION OPERATORS of all generation and transmission resources available for use. (Policy 4 Requirement A.1)
2. The BALANCING AUTHORITY shall document the processes and procedures used to monitor applicable transmission line status, MW and MVAR flows, voltage, LTC settings and status of rotating and static reactive resources. (Policy 4 Requirement A.2)
3. The BALANCING AUTHORITY shall document the processes and procedures used to ensure the provision of appropriate technical information concerning protective relays to operating personnel. (Policy 4 Requirement A.3)
4. The BALANCING AUTHORITY shall document the processes and procedures used to ensure access to information, including weather forecasts and past load patterns, to predict the system's near-term load pattern. (Policy 4 Requirement A.4)
5. The BALANCING AUTHORITY shall document the processes and procedures for the operation of monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action. (Policy 4 Requirement A.5)
6. The BALANCING AUTHORITY shall document the processes and procedures followed to ensure the use of 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. (Policy 4 Requirement A.5.1)
7. The BALANCING AUTHORITY shall document the processes and procedures used to monitor system frequency. (Policy 4 Requirement A.6)

Comments

Edward J. Davis Entergy	1. Please change the bold lead in section from ".. in place to monitor system conditions in accordance with NERC standards." to ".. in place to meet NERC Standard TOP-006 Monitoring System Conditions." 2. Delete all of items 1 through 7. The details in these items repeat the details enumerated in the Standards and are unnecessary. Additionally, if additional requirements are contained in the above they would inappropriately impose new requirements on the BA if they are included in this Template and not included in the Standard. Therefore the above should be deleted.
Alan Boesch NPPD	Monitoring the transmission system is a function that is performed by the transmission operator, the BA is responsible for balancing load and generation. Please modify the requirements to be consistent with the functional model. Documentation is beyond the requirements of the version 0 standards. A better approach that is consistent with the requirements of the version 0 standards is to demonstrate the processes and tools it uses to monitor system criteria associated with balancing load and generation.
Pete Henderson	See comments for A. This appears to overlap with the RC & TOp functions.

IESO Karl Tammar NYISO	

J. Providing Operating Reliability Information

The BALANCING AUTHORITY shall provide documentation within its Integrated Operational Plan that it has the processes and procedures in place to provide operating reliability information in accordance with NERC standards.

1. The BALANCING AUTHORITY shall document the processes and procedures used to provide its RELIABILITY COORDINATOR with operating data that the RELIABILITY COORDINATOR requires for monitoring system conditions within the RELIABILITY COORDINATOR AREA. (Policy 4 Requirement B.4)
2. The BALANCING AUTHORITY shall document the processes and procedures used to provide, upon request, to other BALANCING AUTHORITIES and TRANSMISSION OPERATORS with immediate responsibility for operational reliability, the operating data that are necessary to allow the BALANCING AUTHORITY and TRANSMISSION OPERATOR to perform its operational reliability assessments and to coordinate reliable operations. (Policy 4 Requirement B.5)

Comments

Edward J. Davis Entergy	1. Please change the bold lead in section from "…to meet Real Power Balancing Control Performance standards" to "…to meet NERC Standard BAL-001-0 Real Balancing Control Performance." 2. Delete all of items 1 through 2. The details in these items repeat the details enumerated in the Standards and are unnecessary. Additionally, if additional requirements are contained in the above they would inappropriately impose new requirements on the BA if they are included in this Template and not included in the Standard. Therefore the above should be deleted.
Alan Boesch NPPD	Documentation is beyond the requirements of the version 0 standards. A better approach that is consistent with the requirements of the version 0 standards is to demonstrate the processes and tools it uses for providing operating data to the Reliability Coordinator.
Pete Henderson IESO Karl Tammar NYISO	See comments in first paragraph of the comments for A.

K. Planned Outage Coordination

The BALANCING AUTHORITY shall provide documentation within its Integrated Operational Plan that it has the processes and procedures in place to address planned outage coordination in accordance with NERC standards.

1. The BALANCING AUTHORITY shall document the processes and procedures used to ensure the planning and coordination of 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., among affected RELIABILITY AUTHORITIES, BALANCING AUTHORITIES, and TRANSMISSION OPERATORS as required. (Policy 4 Requirement C.1)
2. The BALANCING AUTHORITY shall document the processes and procedures used to ensure the planning and coordination of scheduled outages of telemetering and control equipment and associated communication channels between the affected BALANCING AUTHORITY AREAS. (Policy 4 Requirement C.3)

Comments

Edward J. Davis Entergy	Please change the bold lead in section from ".. in place to address planned outage coordination in accordance with NERC standards." to ".. in place to address planned outage coordination in accordance with NERC Standard TOP-003 Planned Outage Coordination." Delete all of items 1 through 2. The details in these items repeat the details enumerated in the Standards and are unnecessary. Additionally, if additional requirements are contained in the above they would inappropriately impose new requirements on the BA if they are included in this Template and not included in the Standard. Therefore the above should be deleted.
Alan Boesch NPPD	The BA is not responsible for voltage regulation. Change Reliability Authority to Reliability Coordinator. Documentation is beyond the requirements of the version 0 standards. A better approach that is consistent with the requirements of the version 0 standards is to demonstrate the processes and tools.
Pete Henderson IESO Karl Tammar NYISO	See comments in first paragraph of the comments for A.

L. System Protection Coordination

The BALANCING AUTHORITY shall provide documentation within its Integrated Operational Plan that it has the processes and procedures in place to address system protection coordination in accordance with NERC standards.

1. The BALANCING AUTHORITY shall document the processes and procedures used to ensure system operator familiarity with the purpose and limitations of protection system schemes applied in its BALANCING AUTHORITY AREA. (Policy 4 Requirement D.1)
2. The BALANCING AUTHORITY shall document the processes and procedures used to monitor the status of each SPECIAL PROTECTION SYSTEM in its BALANCING AUTHORITY AREA, and shall notify all affected RELIABILITY AUTHORITIES, TRANSMISSION OPERATORS, and BALANCING AUTHORITIES of each change in status. (Policy 4 Requirement D.6)

Comments

Edward J. Davis Entergy	Please change the bold lead in section from ".. in place to address system protection coordination in accordance with NERC standards." to ".. in place to address system protection coordination in accordance with NERC Standard PRC-001 System Protection Coordination." Delete all of items 1 through 2. The details in these items repeat the details enumerated in the Standards and are unnecessary. Additionally, if additional requirements are contained in the above they would inappropriately impose new requirements on the BA if they are included in this Template and not included in the Standard. Therefore the above should be deleted.
Alan Boesch NPPD	Documentation is beyond the requirements of the version 0 standards. A better approach that is consistent with the requirements of the version 0 standards is to demonstrate the processes and tools.
Pete Henderson IESO Karl Tammar NYISO	See comments in first paragraph of the comments for A. Also, this seems to overlap with the RC & TOP tasks.

M. Reliability Responsibilities and Authorities

The BALANCING AUTHORITY shall provide documentation within its Integrated Operational Plan that it has the responsibilities and authorities to address reliability concerns within its BALANCING AUTHORITY AREA in accordance with NERC standards.

1. The BALANCING AUTHORITY shall document that it has the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its BALANCING AUTHORITY AREA and shall exercise specific authority to alleviate operating emergencies. (Policy 5 Requirement A.2)
2. The BALANCING AUTHORITY shall document the processes and procedures to 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. (Policy 5 Requirement A.2.1)
3. The BALANCING AUTHORITY shall document the processes and procedures used to ensure compliance with RELIABILITY COORDINATOR directives, unless such actions would violate safety, equipment, and regulatory or statutory requirements. (Policy 5 Requirement A.2.2)
4. The BALANCING AUTHORITY shall document the processes and procedures used to inform other potentially affected RELIABILITY AUTHORITIES, BALANCING AUTHORITIES, and TRANSMISSION OPERATORS of real-time or anticipated emergency conditions, and take actions to avoid when possible, or mitigate the emergency. (Policy 5 Requirement A.4)
5. The BALANCING AUTHORITY shall document the processes and procedures used to render all available emergency assistance requested, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements. (Policy 5 Requirement A.5)
6. The BALANCING AUTHORITY shall document the processes and procedures used to notify its RELIABILITY COORDINATOR, TRANSMISSION OPERATORS, and affected BALANCING AUTHORITIES of the removal of a BULK ELECTRIC SYSTEM facility to ensure coordination of the impact resulting from the removal of the facility. (Policy 5 Requirement A.6.1)
7. The BALANCING AUTHORITY shall document the processes and procedures followed to ensure restoration of the real and reactive power balance. (Policy 5 Requirement A.11)

Comments

Edward J. Davis Entergy	1. Please change the bold lead in section from "…to address reliability concerns within its Balancing Authority Area in accordance with NERC standards." to "…to address reliability concerns within its Balancing Authority Area in accordance with NERC Standard TOP-001 Reliability Responsibilities and Authorities." 2. Delete all of items 1 through 7. The details in these items repeat the details enumerated in the Standards and are unnecessary. Additionally, if additional requirements are contained in the above they would inappropriately impose new requirements on the BA if they are included in this Template and not included in the Standard. Therefore the above should be deleted.
Alan Boesch NPPD	Items 1, 2,4 and 6 are the responsibility of the Transmission Operator in the version 0 standards and item 7 is a shared responsibility between the Transmission Operator and the BA. Please modify the requirements to make them consistent with the requirements of the version 0 standards. Documentation should not be required usless it is specified in the version 0 standard. A demonstration of tools and processes is a good alternative.

Pete Henderson IESO Karl Tammar NYISO	See comments in first paragraph of the comments for A. Also, this seems to overlap with the RC & TOP tasks.

N. Communications and Coordination

The BALANCING AUTHORITY shall provide documentation within its Integrated Operational Plan that it has the processes and procedures in place to address communications and coordination in accordance with NERC standards.

1. The BALANCING AUTHORITY shall document the processes and procedures to ensure the provision of communications (voice and data links) with appropriate RELIABILITY AUTHORITIES, BALANCING AUTHORITIES, and TRANSMISSION OPERATORS. (Policy 5 Requirement B.1)
2. The BALANCING AUTHORITY shall document the processes and procedures to notify its RELIABILITY COORDINATOR and all other potentially affected BALANCING AUTHORITIES and TRANSMISSION OPERATORS through predetermined communication paths of any condition that could threaten the reliability of its BALANCING AUTHORITY AREA. (Policy 5 Requirement B.2)
3. The BALANCING AUTHORITY shall document the processes and procedures to ensure the issuance of directives in a clear, concise, and definitive manner; these processes and procedures shall also ensure the recipient of the directive repeats the information back correctly; and address the acknowledgement of the response as correct or repeat the original statement to resolve any misunderstandings. (Policy 5 Requirement B.2.2)

Comments

Edward J. Davis Entergy	1. Please change the bold lead in section from "…in place to address communications and coordination in accordance with NERC standards." to "…in place to address communications and coordination in accordance with NERC Standard COM-002 Communications and Coordination." 2. Delete all of items 1 through 3. The details in these items repeat the details enumerated in the Standards and are unnecessary. Additionally, if additional requirements are contained in the above they would inappropriately impose new requirements on the BA if they are included in this Template and not included in the Standard. Therefore the above should be deleted.
Alan Boesch NPPD	Demonstration of tools used to perform these functions is more appropriate then documentation.
Pete Henderson IESO Karl Tammar NYISO	See comments in first paragraph of the comments for A.

O. Emergency Operations

The BALANCING AUTHORITY shall provide documentation within its Integrated Operational Plan that it has the processes and procedures in place to address emergency operations, implementation of capacity and energy emergency plans, and coordination of emergency operations with other systems in accordance with NERC standards.

1. The BALANCING AUTHORITY shall document the processes and procedures to ensure the implementation of its Capacity and Energy Emergency plans, when required and as appropriate, to reduce risks to the interconnected system. (Policy 5 Requirement C.1)
2. The BALANCING AUTHORITY shall document the processes and procedures to ensure the communication of its current and future system conditions to neighboring BALANCING AUTHORITIES and TRANSMISSION OPERATORS and its RELIABILITY COORDINATOR if they are experiencing an operating emergency. (Policy 5 Requirement C.1)
3. The BALANCING AUTHORITY shall document the processes and procedures to ensure that, if it is deficient of system resources, that it only uses the assistance provided by the INTERCONNECTION's frequency bias for the time needed to implement corrective actions. (Policy 5 Requirement C.2.2)
4. The BALANCING AUTHORITY shall document the processes and procedures to ensure the implementation of all actions necessary, including bringing on all available generation, postponing equipment maintenance, scheduling interchange purchases in advance, and being prepared to reduce firm load in the event it anticipates an operating capacity or energy emergency. (Policy 5 Requirement C.2.1)
5. The BALANCING AUTHORITY shall document the processes and procedures to ensure that if it is experiencing or contributing to an SOL or IROL violation that it takes immediate steps to relieve the condition, which may include firm load shedding. (Policy 5 Requirement D.1)
6. The BALANCING AUTHORITY shall document the processes and procedures to ensure that it operates to prevent the likelihood that a disturbance, action, or non-action will result in a SOL or IROL violation in its BALANCING AUTHORITY AREA or another BALANCING AUTHORITY'S AREA of the INTERCONNECTION. (Policy 5 Requirement D.2)
7. The BALANCING AUTHORITY shall document the processes and procedures to ensure that in instances where there is a difference in derived operating limits that it always operates the BULK ELECTRIC SYSTEM to the most limiting parameter. (Policy 5 Requirement D.2)
8. The BALANCING AUTHORITY shall document the processes and procedures to ensure the disconnection of the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition persists and equipment is endangered. (Policy 5 Requirement D.3)
9. The BALANCING AUTHORITY shall document the processes and procedures to notify its RELIABILITY COORDINATOR and all neighboring BALANCING AUTHORITIES and TRANSMISSION OPERATORS impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter. (Policy 5 Requirement D.4)

Comments

Edward J. Davis Entergy	1. Please change the bold lead in section from "…in place to address emergency operations, implementation of capacity and energy emergency plans, and coordination of emergency operations with other systems in accordance with NERC standards." to "…in place to address emergency operations, implementation of capacity and energy emergency plans, and coordination of emergency operations with other systems in accordance with NERC Standard EOP-002 Capacity and Energy Emergencies."

	2. Delete all of items 1 through 9. The details in these items repeat the details enumerated in the Standards and are unnecessary. Additionally, if additional requirements are contained in the above they would inappropriately impose new requirements on the BA if they are included in this Template and not included in the Standard. Therefore the above should be deleted.
Alan Boesch NPPD	Item 5, 6, 7, 8 and 9 are the responsibility of the Transmission Operator in the version 0 standards. Please modify the requirements to be consistent with the version 0 standards. Documentation should not be required usless it is specified in the version 0 standard. A demonstration of tools and processes is a good alternative.
Pete Henderson IESO Karl Tammar NYISO	See comments in first paragraph of the comments for A. Also, this seems to overlap with the RC & TOP tasks.

P. Disturbance and Sabotage Reporting

The BALANCING AUTHORITY shall provide documentation within its Integrated Operational Plan that it has the processes and procedures in place to address disturbance and sabotage reporting in accordance with NERC standards.

1. The BALANCING AUTHORITY shall document the processes and procedures to ensure that BULK ELECTRIC SYSTEM disturbances are promptly analyzed. (Policy 5 Requirement F.2)
2. The BALANCING AUTHORITY shall document the processes and procedures to ensure the provision of a preliminary written disturbance report to its Regional Council and NERC. The BALANCING AUTHORITY shall document the processes and procedures to ensure the submission within 24 hours of the disturbance or unusual occurrence 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. (Policy 5 Requirement F.3)
3. The BALANCING AUTHORITY shall document the processes and procedures for making operating personnel aware of and for notifying others regarding sabotage events on its facilities and multi-site sabotage affecting larger portions of the INTERCONNECTION. (Policy 5 Requirement G.1)
4. The BALANCING AUTHORITY shall document the processes and procedures for providing its operating personnel with sabotage response guidelines, including personnel to contact, for reporting disturbances due to sabotage events. (Policy 5 Requirement G.2)
5. The BALANCING AUTHORITY shall document the processes and procedures for establishing communications contacts, as applicable, with local Federal Bureau of Investigation (FBI) or Royal Canadian Mounted Police (RCMP) officials and for developing reporting procedures as appropriate to their circumstances. (Policy 5 Requirement G.3

Comments

Edward J. Davis Entergy	1. Please change the bold lead in section from "…in place to address disturbance and sabotage reporting in accordance with NERC standards." to "…in place to address disturbance and sabotage reporting in accordance with NERC Standards EOP-004 Disturbance Reporting and CIP-001 Sabotage Reporting." 2. Delete all of items 1 through 5. The details in these items repeat the details enumerated in the Standards and are unnecessary. Additionally, if additional requirements are contained in the above they would inappropriately impose new requirements on the BA if they are included in this Template and not included in the Standard. Therefore the above should be deleted.
Alan Boesch NPPD	Items 1, 2, 3, 4 and 5 are a joint responsibility of the Transmission Operator, BA , LSE and Generation Operator. Please modify the requirements to be consistent with the requirements of the version 0 standards.
Pete Henderson IESO Karl Tammar NYISO	See comments in first paragraph of the comments for A. Also, this seems to overlap with the RC tasks.

R. Operations Planning

The BALANCING AUTHORITY shall provide documentation within its Integrated Operational Plan that it has the processes and procedures in place to perform 1) normal operations planning, 2) emergency operations planning, 3) load shed planning, and 4) system restoration planning in accordance with NERC standards.

1. Normal Operations Planning

   1.1. The BALANCING AUTHORITY shall document the processes and procedures to ensure the maintenance of a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. (Policy 6 Introduction)

   1.2. The BALANCING AUTHORITY shall document the processes and procedures to ensure the use of available personnel and system equipment to implement these plans to ensure that interconnected systems reliability is maintained. (Policy 6 Introduction)

   1.3. The BALANCING AUTHORITY shall document the processes and procedures to ensure its operating personnel participate in the system planning and design study processes, so that these studies contain the operating personnel perspective and system-operating personnel are aware of the planning purpose. (Policy 6 Introduction)

   1.4. The BALANCING AUTHORITY shall document the processes and procedures to ensure the planning of its current-day, next-day, and seasonal operations in coordination (where confidentiality agreements allow) with neighboring RELIABILITY AUTHORITIES, TRANSMISSION OPERATORS, and BALANCING AUTHORITIES so that normal INTERCONNECTION operation will proceed in an orderly and consistent manner. (Policy 6 Requirement A.1)

   1.5. The BALANCING AUTHORITY shall document the processes and procedures to ensure coordination of its current-day, next-day, and seasonal operations with its TRANSMISSION OPERATORS. (Policy 6 Requirement A.1.1)

   1.6. The BALANCING AUTHORITY shall document the processes and procedures to ensure coordination (where confidentiality agreements allow) its current-day, next-day, and seasonal operations with neighboring BALANCING AUTHORITIES and TRANSMISSION OPERATORS and with its RELIABILITY COORDINATOR. (Policy 6 Requirement A.1.2)

   1.7. The BALANCING AUTHORITY shall document the processes and procedures to ensure operations planning to meet scheduled system configuration, generation dispatch, interchange scheduling and demand patterns. (Policy 6 Requirement A.2.1)

   1.8. The BALANCING AUTHORITY shall document the processes and procedures to ensure operations planning to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional, and local reliability requirements. (Policy 6 Requirement A.2.2)

   1.9. The BALANCING AUTHORITY shall document the processes and procedures to ensure operations planning to meet capacity and energy reserve requirements, including the deliverability/capability for any single contingency. (Policy 6 Requirement A.2.3)

   1.10. The BALANCING AUTHORITY shall document the processes and procedures to ensure operations planning that respects voltage and/or reactive limits, including the deliverability/capability for any single contingency. (Policy 6 Requirement A.2.4)

   1.11. The BALANCING AUTHORITY shall document the processes and procedures to ensure operations planning to meet Interchange Schedules. (Policy 6 Requirement A.2.5)

1.12. The BALANCING AUTHORITY shall document the processes and procedures to ensure operations planning to respect all SYSTEM OPERATING LIMITS (SOLs). (Policy 6 Requirement A.2.6)

1.13. The BALANCING AUTHORITY shall document the processes and procedures to ensure maintenance of accurate computer models for analyzing and planning system operations. (Policy 6 Requirement A.7)

2. Emergency Operations Planning

2.1. The BALANCING AUTHORITY shall document that it has operating agreements with ADJACENT BALANCING AUTHORITIES that, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote BALANCING AUTHORITIES. (Policy 6 Requirement B.1)

2.2. The BALANCING AUTHORITY shall document that it is staffed with adequately trained operating personnel. (Policy 6 Requirement B.2)

2.3. The BALANCING AUTHORITY shall document that it has emergency plans that will enable it to mitigate operating emergencies. (Policy 6 Requirement B.5)

2.4. The BALANCING AUTHORITY shall document the processes and procedures to provide for an annual review and update of each emergency plan. The BALANCING AUTHORITY shall provide a copy of its updated emergency plans to its RELIABILITY COORDINATOR and to neighboring TRANSMISSION OPERATORS AND BALANCING AUTHORITIES. (Policy 6 Requirement B.6)

2.5. The BALANCING AUTHORITY shall document the processes and procedures to ensure the coordination of its emergency plans with other RELIABILITY AUTHORITIES, TRANSMISSION OPERATORS, AND BALANCING AUTHORITIES as appropriate. (Policy 6 Requirement B.7)

3. Load Shed Planning

3.1. The BALANCING AUTHORITY shall document the processes and procedures to ensure that, after it has taken all other remedial steps and it remains operating with insufficient generation or transmission capacity, it will shed customer load rather than risk an uncontrolled failure of components or cascading outages of the INTERCONNECTION. (Policy 6C Introduction)

3.2. The BALANCING AUTHORITY shall document that it has established plans for automatic load shedding. (Policy 6 Requirement C.1)

3.3. The BALANCING AUTHORITY shall document that it has coordinated load-shedding plans between other interconnected TRANSMISSION OPERATOR and BALANCING AUTHORITY AREAS. (Policy 6 Requirement C.1.1)

3.4. The BALANCING AUTHORITY shall document that it has the processes and procedures to shed additional load if there is insufficient generating capacity to restore system frequency following automatic under-frequency load shedding after separation from the INTERCONNECTION. (Policy 6 Requirement C.1.2.3)

3.5. The BALANCING AUTHORITY shall document that it has coordinated automatic load shedding throughout its BALANCING AUTHORITY AREA with under-frequency isolation of generating units, tripping of shunt capacitors, and other automatic actions that will occur under abnormal frequency, voltage, or power flow conditions. (Policy 6 Requirement C.1.2.4)

3.6. The BALANCING AUTHORITY shall document that it has plans for operator-controlled manual load shedding to respond to real-time emergencies. The BALANCING AUTHORITY shall document that it has processes and procedures to ensure the implementation of load shedding in a timeframe adequate for responding to the emergency. (Policy 6 Requirement C.1.2.4)

4. System Restoration Planning

4.1. The BALANCING AUTHORITY shall document that it has a restoration plan to reestablish its electric system in a stable and orderly manner in the event of a partial or total shutdown of its system, including necessary operating instructions and procedures to cover emergency conditions, and the loss of vital telecommunications channels. (Policy 6 Requirement D.1)

4.2. The BALANCING AUTHORITY shall document that it has the processes and procedures in place that requires, at a minimum, an annual review and update of its restoration plan, a review whenever it makes changes in the power system network, and a review to correct deficiencies found during simulated restoration exercises. (Policy 6 Requirement D.1.1)

4.3. The BALANCING AUTHORITY shall document that it has coordinated development of its restoration plan with neighboring RELIABILITY AUTHORITIES, TRANSMISSION OPERATORS, and BALANCING AUTHORITIES. (Policy 6 Requirement D.1.3)

4.4. The BALANCING AUTHORITY shall document that it has processes and procedures requiring periodic testing of its telecommunication facilities needed to implement its restoration plan. (Policy 6 Requirement D.1.4)

4.5. The BALANCING AUTHORITY shall document that it has the processes and procedures to ensure training of its operating personnel in the implementation of its restoration plan. (Policy 6 Requirement D.2)

4.6. The BALANCING AUTHORITY shall document that it has the processes and procedures to ensure verification of its restoration procedures by actual testing or by simulation. (Policy 6 Requirement D.3)

4.7. The BALANCING AUTHORITY shall document that it has the processes and procedures to ensure the availability and location of black start capability within its BALANCING AUTHORITY AREA to meet the needs of its restoration plan. (Policy 6 Requirement D.4)

Comments

Edward J. Davis Entergy	1. Please change the bold lead in section from "…in place to perform 1) normal operations planning, 2) emergency operations planning, 3) load shed planning, and 4) system restoration planning in accordance with NERC standards." to "…in place to perform 1) normal operations planning, 2) emergency operations planning, 3) load shed planning, and 4) system restoration planning in accordance with NERC Standard TOP-002 Normal Operations Planning, EOP-001 Emergency Operations Planning, EOP-003 Load Shedding Plans, and EOP-005 System Restortation Plans." 2. Delete all of items 1 through 4. The details in these items repeat the details enumerated in the Standards and are unnecessary. Additionally, if additional requirements are contained in the above they would inappropriately impose new requirements on the BA if they are included in this Template and not included in the Standard. Therefore the above should be deleted.
Alan Boesch NPPD	Items 1.1, 1.2, 1.3, 1.4, 1.5. 1.6, 1.7 1.8, 1.10, 1.12, 1.13, 2.3, 2.4 2.5, 3.1, 3.2, 3.3, 3.4, 3.5, 3.6, 4.1, 4.2, 4.3, 4.4, 4,5, 4,6, and 4.7 do not match version 0 standards. Please modify these items to be consistent with the requirements of the version 0 standards.
Pete Henderson IESO Karl Tammar NYISO	See comments in first paragraph of the comments for A. Also, this seems to overlap with the RC & TOP tasks.

S. Plans for Loss of Control Center Functionality

The BALANCING AUTHORITY shall provide documentation within its Integrated Operational Plan that it has the processes and procedures in place to ensure performance of its reliability functions in the event it loses control center functionality. (Policy 6 Requirement 1)

Comments

Edward J. Davis Entergy	1. Please change the bold lead in section from "…in place to ensure performance of its reliability functions in the event it loses control center functinoality." to "…in place to ensure performance of its reliability functions in the event it loses control center functionality in accordance with NERC Standard EOP-008 Plans for Loss of Control Center Functionality."
Alan Boesch NPPD	This is a joint responsibility between the Transmission Operator and the BA. Please modify this requirement to be consistent with the requirements of the version 0 standards.
Pete Henderson IESO Karl Tammar NYISO	See comments in first paragraph of the comments for A.

T. Telecommunications

The BALANCING AUTHORITY shall provide documentation within its Integrated Operational Plan that it has the processes and procedures in place to ensure the provision of telecommunications in accordance with NERC standards.

1. The BALANCING AUTHORITY shall document that it has processes and procedures to ensure the provision of adequate and reliable telecommunications facilities internally and with RELIABILITY AUTHORITIES, TRANSMISSION OPERATORS, and BALANCING AUTHORITIES for the exchange of INTERCONNECTION and operating information necessary to maintain reliability. (Policy 7 Requirement A.1)
2. The BALANCING AUTHORITY shall document that it has processes and procedures to manage, alarm, test and/or actively monitor vital telecommunications facilities. The processes and procedures shall ensure that special attention is given to emergency telecommunications facilities and equipment not used for routine communications. (Policy 7 Requirement A.3)
3. The BALANCING AUTHORITY shall document that it has processes and procedures to ensure the coordination of telecommunications. (Policy 7 Requirement B.1)
4. The BALANCING AUTHORITY shall document that it has processes and procedures to ensure the provision of written operating instructions and procedures to enable continued operation of the system during loss of telecommunications facilities. (Policy 7 Requirement C.1)

Comments

Edward J. Davis Entergy	1. Please change the bold lead in section from "…in place to ensure the provision of telecommunications in accordance with NERC standards." to "…in place to ensure the provision of telecommunications in accordance with NERC Standard COM-001 Telecommunications." 2. Delete all of items 1 through 4. The details in these items repeat the details enumerated in the Standards and are unnecessary. Additionally, if additional requirements are contained in the above they would inappropriately impose new requirements on the BA if they are included in this Template and not included in the Standard. Therefore the above should be deleted.
Alan Boesch NPPD	This is a joint responsibility between the Transmission Operator and the BA. Please modify this requirement to be consistent with the requirements of the version 0 standards.
Pete Henderson IESO Karl Tammar NYISO	See comments in first paragraph of the comments for A.

U. Operating Personnel

The BALANCING AUTHORITY shall provide documentation within its Integrated Operational Plan that it has provided its operating personnel 1) the responsibility and authority and 2) the training to perform the reliability functions identified in its Integrated Operational Plan. In addition, the Balancing Authority shall provide documentation within its Integrated Operational Plan that all its operating positions are staffed with NERC certified operating personnel.

1. The BALANCING AUTHORITY shall document that its operating personnel have the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the BULK ELECTRIC SYSTEM. (Policy 8 Standard A.1)
2. The BALANCING AUTHORITY shall document that it has a training program for operating personnel. (Policy 8 Requirement B.1)
3. The BALANCING AUTHORITY shall document that its training program for operating personnel provides at least five days per year of operating personnel training and drills in system emergencies, using realistic simulations. (Policy 6 Requirement B.2)
4. The BALANCING AUTHORITY shall document that it has staffed all operating positions with NERC certified operating personnel in accordance with NERC criteria. (Policy 8 Requirement C.1)

Comments

Edward J. Davis Entergy	1. Please change the bold lead in section from "…provided its operating personnel 1) the responsibility …. are staffed with NERC certified operating personnel." to "… provided its operating personnel 1) the responsibility …… are staffed with NERC certified operating personnel in accordance with NERC Standards PER-001 Operating Personnel Responsibilty and Authority and PER-002 Operating Personnel Training." 2. Delete all of items 1 through 4. The details in these items repeat the details enumerated in the Standards and are unnecessary. Additionally, if additional requirements are contained in the above they would inappropriately impose new requirements on the BA if they are included in this Template and not included in the Standard. Therefore the above should be deleted.
Alan Boesch NPPD	These requirements are also applicable to the Transmission Operator in the version 0 standards.
Pete Henderson IESO Karl Tammar NYISO	See comments in first paragraph of the comments for A.

Item 6. Recommendation List and Action Plan

Action

Review recommendations and agree on action plan for each.

Attachment

Recommendations from the Functional Model-Reliability Standards Coordination Task Force and the Interchange Authority Implementation Task Force (from Item 3).

Background

The FMWG+ will probably spend considerable time on this table deciding how to approach each recommendation and listing its decisions and actions for the duration of this project.

The working group can take several different approaches to this list, but it might be best to first spend time reviewing the entire list to make sure everyone understands the recommendations and to determine if there are any conflicts among those recommendations. It's better to iron those out now rather than later.

Then the working group could decide how it wants to tackle each item. Some may require the entire group's participation, while others can be handed to smaller groups or staff for drafting.

Once the working group is satisfied with the list of recommendations, it can begin to work on them (after we've reviewed the Timeline and Deliverables in the next item.)

Layout. The Recommendations List from the FMRSCTF and IAITF is divided into three sections:

1. Functional Model. These are the recommendations that deal directly with the Functional Model. It includes the recommendations from the Functional Model-Reliability Standards Coordination Task Force and the Interchange Authority Implementation Task Force who is dealing with the Interchange Authority concepts and operability.

2. Regional Reliability Plan Outlines.

3. Compliance and Accountability. It may not be obvious how to handle some of these recommendations, and the working group will need to discuss each of them to see how they fit with the overall scope of this project.

Item 7. Timeline and Deliverables

Action

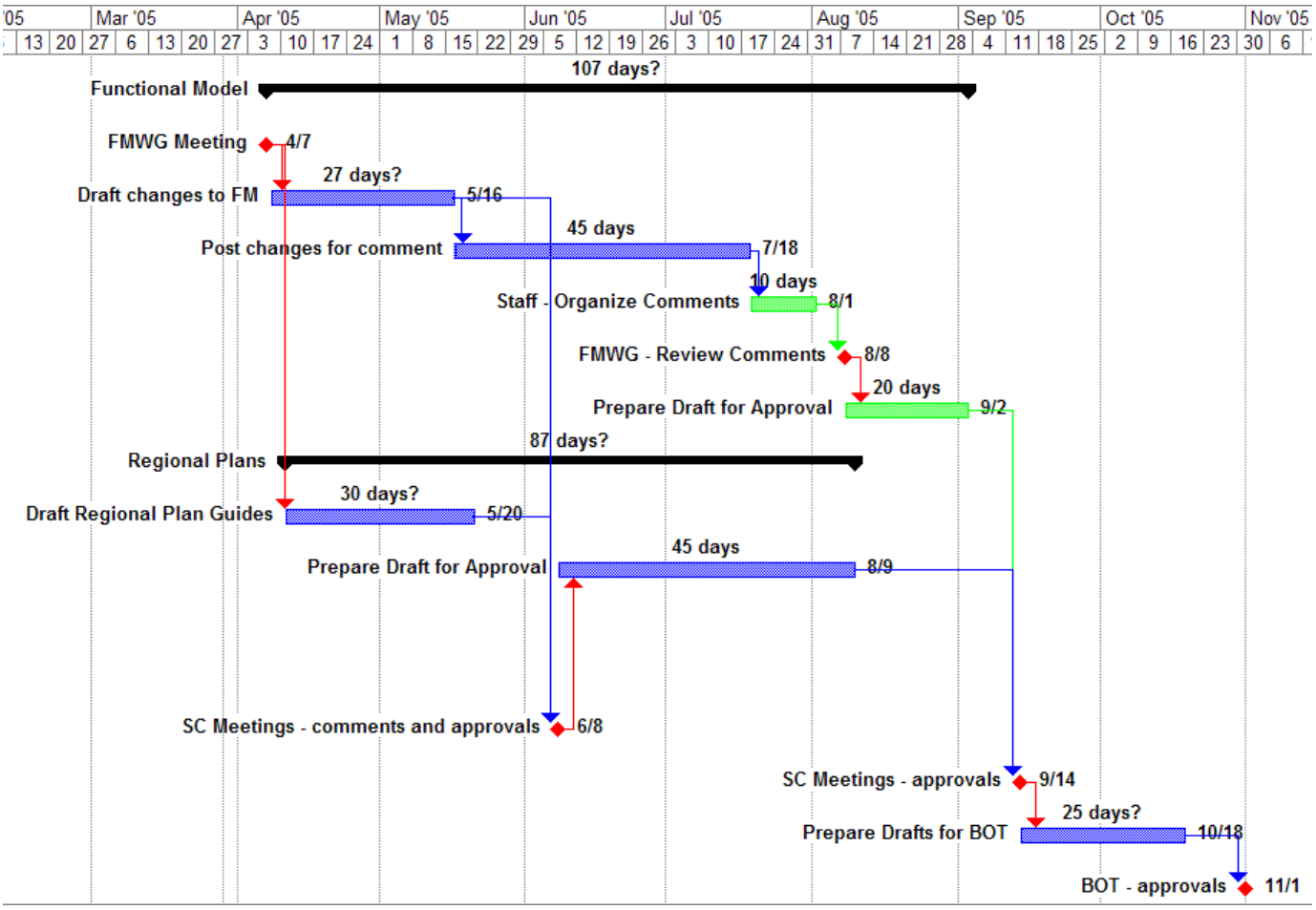
Review timeline and deliverables.

Background

As a minimum, the working group will be reporting its progress regularly to the Technical Steering Committee. Assuming the working group will recommend changes to the Functional Model and the regional reliability plan guides, it will bring those changes to the standing committees for discussion and approval. Changes to the Functional Model will ultimately need Board of Trustees approval.

The Functional Model-Reliability Standards Coordination Task Force prepared a task list and timeline that the Operating Committee and Planning Committee approved at their March 2005 meetings. The timeline is theoretically possible, but may be unrealistic given the other tasks that the working group members and staff are involved in, and the possibility that we may need to post the Functional Model more than once — and because the project crosses the summer vacation periods.

The chart below shows the timeline that the FMRSCTF recommended.



Item 8. Define Near-Term Tasks, Next Meeting Agenda, and Work on Recommendations

Before the working group adjourns its meeting, it must do two things:

1. Define its near-term goals and objectives for meeting those goals, and

2. Set its next meeting agenda. The working group should consider using conference calls and WebEx meetings as appropriate to hasten its work and reduce travel.

Providing time remains, the working group may wish to begin tackling some of the recommendations. For example:

- Decide how to approach the Reliability Authority, Transmission Operator, and Interchange Authority renaming.

- Decide how to deal with the Interchange Authority Implementation Task Force's near-, mid-, and long-term recommendations.

- Discuss the contents of the regional reliability plans. For example, what functions should the plans cover? And how do we handle RTOs or ISOs that are in more than one Region?