BOARD OF TRUSTEES MEETING

September 15, 1997 — 4–6 p.m.
September 16, 1997 — 8:30 a.m.–12 noon

Radisson Plaza Hotel Minneapolis
Minneapolis, Minnesota

AGENDA

Monday, September 15, 1997 — 4 p.m.

1. Introductions and Chairman's Remarks

*2. Bylaws Changes

*3. Nominating Committee Report

Consent Agenda

*4. Approval of Minutes of May 5–6, 1997 Meeting
*5. Treasurer's Report
*6. Engineering Committee Report
*7. Operating Committee Report

*8. Committee Organization
   a. Organizational Structure of the Engineering Committee Document
   b. Operating Committee Organization and Procedures Document
   c. Operating Committee Compliance Subcommittee

9. Comments by Regional Chairmen and Other Board Members

*10. Future Role of NERC Task Force — II
   a. Electric Reliability Panel
   b. Mandatory Compliance Initiatives
   c. Alternate Funding Approach for NERC

Tuesday, September 16, 1997 — 8:30 a.m.

*11. Strategic Initiatives for NERC
   a. Available Transfer Capability
   b. Standards
   c. Security Process
   d. Interconnected Operations Services

*12. Reliability Assessment Subcommittee

*13. 1998 Budget

14. Comments by Observers

*15. Future Meetings

16. Other Business

*Background material included

Board of Trustees

MAAC	Phillip G. Harris President and Chief Executive Officer	PJM Interconnection, L.L.C. 955 Jefferson Avenue Valley Forge Corporate Center Norristown, Pennsylvania 19403-2497	Ph: (610) 666-8800 Fx: (610) 666-4281 Em:harrispg@pjm.com
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MAIN	Gilbert W. Moorman Vice President Power Supply	Central Illinois Public Service Company 607 East Adams Street Springfield, Illinois 62739	Ph: (217) 525-5533 Fx: (217) 535-5066
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MAPP	David L. Mangskau Director	ENRON Power Marketing, Inc. 98 Country Club Drive Bismarck, North Dakota 58501	Ph: (701) 258-4482 Fx: (701) 258-5542
Regional Chairman NPCC	John E. (Jed) Deegan Chairman	Northeast Power Coordinating Council 162 Upland Circle Brewster, Massachusetts 02631	Ph: (508) 240-2119 Fx: (508) 240-1327 Em:JEDDEEGAN@aol.com
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Regional Chairman SERC	Fred D. Williams Senior Vice President, Southern Wholesale Energy	Southern Company Services, Inc. 333 Piedmont Avenue, N.E. Bin 10240 Atlanta, Georgia 30308-3374	Ph: (404) 506-6599 Fx: (404) 506-3186 Em:Fred.D.Williams@scsnet.com
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WSCC	Jack Davis Executive Vice President - Commercial Operations	Arizona Public Service Company P.O. Box 53999 MS 9080 Phoenix, Arizona 85072-3999	Ph: (602) 250-3529 Fx: (602) 250-3002
Affiliate Member ASCC	Charles Walls General Manager	Alaska Village Electric Cooperative 4831 Eagle Street Anchorage, Alaska 99503	Ph: (907) 561-1818 Fx: (907) 562-4086
Canada	Jacques Regis President	HQ Transmission Services Division of Hydro-Quebec	Ph: (514) 289-5334 Fx: (514) 289-5318

		Complexe Desjardins, Tour de l'est 12e etage, Case Postal 10 000 Montreal, Quebec H5B 1H7	
Canada	Walter Saponja President and Chief Operating Officer	TransAlta Utilities Corporation Box 1900 110 12th Avenue, S.W. Room 903 Calgary, Alberta T2P 2M1	Ph: (403) 267-7322 Fx: (403) 267-3630
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Power Marketer	Jeffrey K. Skilling President and Chief Operating Officer	Enron Corp. 1400 Smith Street Houston, Texas 77002	Ph: (713) 853-6894 Fx: (713) 646-8381
Power Marketer	Paul F. Barber Vice President, Transmission and Engineering	Citizens Power LLC 530 Atlantic Avenue Boston, Massachusetts 02210	Ph: (617) 912-6052 Fx: (617) 912-5702 Em:PaulB@ CitizensPower.com
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Federal	Randall W. Hardy Administrator and Chief Executive Officer	Bonneville Power Administration P.O. Box 3621 Portland, Oregon 978208-3621	Ph: (503) 230-5102 Fx: (503) 230-4018
Federal	J. M. Shafer Administrator	Western Area Power Administration P.O. Box 3402 Golden, Colorado 80401	Ph: (303) 275-1513 Fx: (303) 275-1717 Em:jshafer@wapa.gov
State/Municipal	Marvin L. Carraway General Manager	Clarksdale Public Utilities Commission P.O. Box 70 Clarksdale, Mississippi 38614	Ph: (601) 627-8403 Fx: (601) 627-8404 Em:epuadmin@ clarksdale.com
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Board of Trustees Observers

Regional Managers

ECAR	Brantley H. Eldridge Executive Manager	East Central Area Reliability Coordination Agreement 220 Market Avenue South Suite 501 Canton, Ohio 44702-2182	Ph: (330) 456-2488 Fx: (330) 456-3648 Em:brante@ecar.org
ERCOT	Tom Sweatman Executive Director	Electric Reliability Council of Texas 7200 MoPac Expressway Suite 250 Austin, Texas 78731-2563	Ph: (512) 343-7215 Fx: (512) 343-8134 Em:tsweatman@ ercot.com
FRCC	J. Ken Wiley Executive Director	Florida Reliability Coordinating Council 405 Reo Street Suite 100 Tampa, Florida 33609-1009	Ph: (813) 289-5644 Fx: (813) 289-5646 Em:kwiley@frcc.com
MAAC	Phillip G. Harris President and Chief Executive Officer	PJM Interconnection, L.L.C. 955 Jefferson Avenue Valley Forge Corporate Center Norristown, Pennsylvania 19403-2497	Ph: (610) 666-8800 Fx: (610) 666-4281 Em:harrispg@pjm. com
MAIN	Richard A. Bulley Executive Director	Mid-America Interconnected Network, Inc. 939 Parkview Boulevard Lombard, Illinois 60148-3267	Ph: (630) 261-2626 Fx: (630) 691-4222 Em:rab@maininc.org
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SERC	James N. Maughn Administrative Manager	Southeastern Electric Reliability Council 600 North 18th Street 7N-8250 Birmingham, Alabama 35202-2625	Ph: (205) 257-6361 Fx: (205) 257-0408 Em:jmaughn@serc1. org
SPP	John J. Marschewski, Jr. President	Southwest Power Pool 415 North McKinley Plaza West -- #700 Little Rock, Arkansas 72205-3020	Ph: (501) 664-0146 Fx: (501) 664-9553 Em:jmarsch@spp.org

WSCC	Dennis E. Eyre Executive Director	Western Systems Coordinating Council University of Utah, Research Park 540 Arapeen Drive Suite 203 Salt Lake City, Utah 84108	Ph: (801) 582-0353 Fx: (801) 582-3918 Em:dennis@wscc.com
Affiliate Member **ASCC**	Theron C. (T.C.) Wilson Interim Executive Director	Alaska Systems Coordinating Council 703 West Tudor Road Suite 101 Anchorage, Alaska 99503	Ph: (907) 561-6196 Fx: (907) 561-6206 Em:ascc@ptialaska.net

Technical Steering Committee

OC Chairman	Gregory A. Cucchi Vice President of Power Delivery	PECO Energy Company 2301 Market Street S25-1 Philadelphia, Pennsylvania 19101-8699	Ph: (215) 841-4710 Fx: (215) 841-6374 Em:gcucchi@peco-energy.com
EC Chairman	Garey C. Rozier Director of Bulk Power SupplySouthern Wholesale Energy	Southern Company Services, Inc. 333 Piedmont Avenue, N.E. Bin 10220 Atlanta, Georgia 30308-3374	Ph: (404) 526-7250 Fx: (404) 526-7407 Em:Garey.C.Rozier@gpc.com
OC Vice Chairman	William C. Phillips Director - Security Operations	Southwest Power Pool 415 North McKinley Plaza West -- #700 Little Rock, Arkansas 72205-3020	Ph: (501) 664-0146 Fx: (501) 664-9553 Em:wphillips@spp.org
EC Vice Chairman	Harlow R. Peterson Consultant Planning Analyst	Salt River Project P.O. Box 52025 Phoenix, Arizona 85072-2025	Ph: (602) 236-2205 Fx: (602) 236-2201 Em:hrpeters@srp.gov
President NERC	Michehl R. Gent President	North American Electric Reliability Council 116-390 Village Boulevard Princeton, New Jersey 08540-5731	Ph: (609) 452-8060 Fx: (609) 452-9550 Em:mike.gent@nerc.com
Vice President NERC	David R. Nevius Vice President	North American Electric Reliability Council 116-390 Village Boulevard Princeton, New Jersey 08540-5731	Ph: (609) 452-8060 Fx: (609) 452-9550 Em:dave.nevius@nerc.com

Agenda Item 2
BOT Meeting
September 15–16, 1997

Bylaws Changes

The NERC staff has been requested to prepare proposed changes to the Bylaws for the Board's consideration in three areas. The first change addresses the addition of two customer (end-use) sector representatives to the Board. The other two changes are of a housekeeping nature. These proposed changes are described below and are also included in the attached Bylaws (Exhibit 1) as underlines (additions) and strikeouts (removals).

NERC's Bylaws can be changed in two ways as outlined in Article X. The Bylaws may be amended by the Members or the Board. The Members are the ten Regional Councils and the Board is comprised of Regional Council representatives (Trustees), Additional Trustees, and Officers. For the Members to make changes, they must receive written notice of the subject matter of the proposed changes not less than ten nor more than 60 days prior to the date of a Meeting of Members. For the Trustees to make the same changes, they must have had written notice of the subject matter of the proposed changes at the previous meeting of the Board. Because "technically" written notice of the intent to change the Bylaws was not provided at the May 1997 Board meeting, the "Member" method of changing the Bylaws will be used to address the proposed changes to the Bylaws on customer (end-use) sector representatives and the two housekeeping items. The notice to the Members is attached as Exhibit 2.

Article III, Sections 1a and 1b

At its May 5–6, 1997 meeting, the Board of Trustees approved a resolution adding two seats to the Board and Committees for representatives of the customer (end-use) sector. To implement this resolution, the NERC staff was asked to prepare proposed changes to the Bylaws for the Board's consideration at its September 1997 meeting.

After discussion with several Officers of NERC, the staff recommends the following modifications to Article III, Sections 1a and 1b as follows:

ARTICLE III
Board of Trustees

Section 1 — Board of Trustees — The business and affairs of the Corporation shall be managed by the Board of Trustees (Board). The Board shall be comprised of two representatives (the Trustees of the Board, hereinafter referred to as "Trustees") of each Member, who shall be elected or appointed by such Member and who shall serve for such term as each Member may determine, and the additional Trustees as provided hereinafter.

a. Should the Board so selected at any time not include at least two representatives (Trustees) from Canada or not include at least two representatives (Trustees) of each segment of the electric industry (i.e., (a) federal, (b) investor-owned, (c) rural electric cooperative, (d) state/municipal, (e) exempt wholesale generator, ~~and~~ (f) power marketer<u>, and (g) customer</u>), the Board shall elect from a list provided for this purpose by the Members, an additional Trustee or Trustees, and shall fill vacancies of such Trustee or Trustees, as may be required to effect such representation. Such additional Trustees shall serve until the second succeeding Annual Meeting of the Members.

b. Each Trustee, except the additional Trustees for the customer segment, shall be a representative of a Member or a participant in a Member.

Article II, Section 1

To be consistent with the change in the number of Board meetings per year from four (January, April, July, and October) to three (January, May, and September), it is recommended that the designated month for the Annual Meeting of Members in Article II, Section 1 be changed from April to May as indicated below:

ARTICLE II
Meetings of Members

Section 1 — Annual Meeting of Members — The Annual Meeting of Members for the transaction of such business as shall come before the meeting shall be held at 9 a.m. on the second Tuesday of ~~April~~ May of each year, or if that day is a legal holiday, on the next succeeding business day, at the principal office of the Corporation, or such other time, date, and place as shall be specified in the written notice of the time, date, place, and purposes of the meeting given to the Members not less than ten nor more than sixty days prior to the date of the meeting.

Article IX, Section 2

To correct a reference within the Bylaws, it is recommended that the reference cited in Article IX, Section 2 be changed from Section 15 to Article IX, Section 1. This necessary reference change was inadvertently omitted when the Bylaws were reformatted in July 1994. The following modification to Article IX, Section 2 would correct this omission:

ARTICLE IX
Fiscal Matters

Section 1 — Expenses — The expenses of each Trustee, each member of a committee or task force, the Secretary-Treasurer and the Assistant Secretary-Treasurer, unless employed to work full time on the affairs of the Corporation, shall be borne by the party by whom he or she is regularly employed, or the Member or Affiliate Member of which such party is a representative or in which such party is a participant.

Administrative expenses of the Corporation shall be authorized by the Board through the adoption of an annual budget at a meeting duly called for that purpose or at a regular meeting of the Board. Fifty percent of such administrative expenses in each year shall be borne by the Members and Affiliate Members in proportion to the total actual net energy for load of the reporting electric utility systems within their Regional boundaries for the year preceding the previous calendar year, and the remaining fifty percent of such expenses shall be borne by the Members and Affiliate Members in equal shares. Each Member's or Affiliate Member's net energy for load shall be the value reported in the NERC annual Electricity Supply & Demand report. The Board may waive any portion of the assessment or establish a minimum (or lesser) assessment for Affiliate Members.

Section 2 — Withdrawal of Members — Upon thirty days' written notice to the Board, any Member or Affiliate Member may withdraw from membership provided, however, any such withdrawing Member or Affiliate Member shall remain liable for all expenses to be borne by such Member or Affiliate Member as set forth in ~~Section 15~~ Article IX, Section 1 to the extent incurred to the effective date of such withdrawal.

Actions: The Chairman will call to order a Meeting of the Members. The Members will be asked to approve revisions to the Bylaws to:

a. Add at least two customer representatives to the Board.
b. Change the month of the Annual Meeting of Members from April to May.
c. Correct the reference in Article IX, Section 2 from Section 15 to Article IX, Section 1.

Exhibit 1

BYLAWS

OF THE

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

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

Phone 609-452-8060
Fax 609-452-9550

Revised ~~January 6, 1997~~ September , 1997

BYLAWS

OF THE

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

CONTENTS

BYLAWS

OF THE

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

ARTICLE I
Membership

Section 1 — Categories — The North American Electric Reliability Council, hereinafter referred to as the "Corporation," shall have two categories of membership, Member and Affiliate Member.

a. Members — The Members are the following Regional Electric Reliability Councils (Regional Councils): East Central Area Reliability Coordination Agreement, Electric Reliability Council of Texas, Florida Reliability Coordinating Council, Mid-Atlantic Area Council, Mid-America Interconnected Network, Inc., Mid-Continent Area Power Pool, Northeast Power Coordinating Council, Southeastern Electric Reliability Council, Southwest Power Pool, and Western Systems Coordinating Council. Membership may be amended from time to time in accordance with this Article I.

b. Affiliate Members — The Alaska Systems Coordinating Council is an Affiliate Member. Affiliate membership may be amended from time to time in accordance with this Article I.

Section 2 — Member Qualifications — Membership in the Corporation is voluntary and open to any Regional Electric Reliability Council (Regional Council), wherein that Regional Council meets the following qualifications of full membership:

a. A Regional Council shall be comprised of members from one or more segments of the electric industry as defined in, but not limited to, Article III, Section 1a of these Bylaws. A member of a Regional Council may also be a member of one or more other Regional Councils, if permitted by the said Regional Councils.

b. The Regional Council members shall be engaged in the generation, transmission, distribution, or marketing of electric energy to wholesale or retail electric customers.

c. A Regional Council shall be comprised of two or more contiguous bulk electric systems, each of which is electrically interconnected by two or more transmission lines with one or more other contiguous member systems within that Regional Council.

   A bulk electric system is defined as that portion of an electric utility system, which encompasses the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher.

d. The Regional Council shall be electrically interconnected by two or more transmission lines with one or more other contiguous Regional Councils.

e. The total net energy for load of all members located within a Regional Council's boundaries shall be at least 100 million MWh per year.

Section 3 — Affiliate Member Qualifications — A Regional Council that does not meet one or more of the qualifications for full membership as set forth in Article I, Section 2 may be admitted as an Affiliate Member of the Corporation. Affiliate membership entitles that Regional Council to have one non-voting representative who may attend all regular meetings of the NERC Board.

Section 4 — Obligations — A Member or Affiliate Member Regional Council, on behalf of its members, shall agree, in writing, to accept the responsibility to promote, support, and comply with the purposes and policies of the Corporation as set forth in its Certificate of Incorporation, Bylaws, and Planning and Operating Policies that from time to time may be amended, adopted, or approved. In addition, it shall provide for its share of the financial support of the Corporation in a timely manner.

Section 5 — Application — A Regional Council shall apply for membership in the Corporation by filing its request, in writing, with the Chairman of the Board of Trustees and with a copy to the President of the Corporation.

Section 6 — Approval — A Regional Council shall be admitted as a Member or Affiliate Member of the Corporation by the Members or the Board of Trustees (Board) by a two-thirds vote at respective meetings of the Members or the Board at which a quorum of the Members or the Board entitled to vote is present.

Section 7 — Term — Membership in the Corporation shall be retained as long as a Member or Affiliate Member meets its respective qualifications and obligations of membership as set forth in Article I, Sections 2, 3, and 4.

Section 8 — Removal — The Members or the Board may terminate the membership of a Member or an Affiliate Member if in the judgment of the Members or the Board that Member or Affiliate Member has violated its obligations and responsibilities to the Corporation. This termination shall require a two-thirds vote of the Members or the Board at respective meetings of the Members or the Board at which a quorum of the Members or the Board entitled to vote is present. The Member in question or its Trustees shall be excluded from the termination vote.

ARTICLE II
Meetings of Members

Section 1 — Annual Meeting of Members — The Annual Meeting of Members for the transaction of such business as shall come before the meeting shall be held at 9 a.m. on the second Tuesday of ~~April~~ May of each year, or if that day is a legal holiday, on the next succeeding business day, at the principal office of the Corporation, or such other time, date, and place as shall be specified in the written notice of the time, date, place, and purposes of the meeting given to the Members not less than ten nor more than sixty days prior to the date of the meeting.

Section 2 — Special Meetings of Members — Special meetings of Members may be called for any purpose or purposes by the Chairman or by any two Members. Special meetings shall be held at the principal office of the Corporation or at such other place as shall be specified in the notice of meeting. Special meetings shall be called upon written notice of the time, date, place, and purposes of the meeting given to all Members not less than ten nor more than sixty days prior to the date of the meeting.

Section 3 — Waivers of Notice of Meetings of Members; and Member Meeting Adjournments — Notice of a meeting of Members need not be given to any Member who signs a waiver of notice, in person or by proxy, whether before or after the meeting. The attendance of any Member at a meeting, in person or by proxy, without protesting prior to the conclusion of the meeting the lack of notice of such meeting, shall constitute a waiver of notice of the meeting by such Member.

When any meeting of Members is adjourned to another time or place, it shall not be necessary to give notice of the adjourned meeting if the time and place to which the meeting is adjourned are announced at the meeting at which the adjournment is taken, and if at the adjourned meeting only such business is transacted as might have been transacted at the original meeting.

Section 4 — Action Without a Meeting of Members — Any action, required or permitted to be taken at a meeting of Members, may be taken without a meeting if all the Members entitled to vote on the action consent to the action in writing. The call for action without a meeting of Members may be initiated by the Chairman or by any two Members, and requires written notice to all Members of the subject matter for action not less than ten nor more than sixty days prior to the date on which action is to be voted. The Members shall receive written notice of the results within ten days of the action vote, and all written responses of the Members shall be filed with the minutes of proceedings of Members.

ARTICLE III
Board of Trustees

Section 1 — Board of Trustees — The business and affairs of the Corporation shall be managed by the Board of Trustees (Board). The Board shall be comprised of two representatives (the Trustees of the Board, hereinafter referred to as "Trustees") of each Member, who shall be elected or appointed by such Member and who shall serve for such term as each Member may determine, and the additional Trustees as provided hereinafter.

a. Should the Board so selected at any time not include at least two representatives (Trustees) from Canada or not include at least two representatives (Trustees) of each segment of the electric industry (i.e., (a) federal, (b) investor-owned, (c) rural electric cooperative, (d) state/municipal, (e) exempt wholesale generator, ~~and~~ (f) power marketer, and (g) customer), the Board shall elect from a list provided for this purpose by the Members, an additional Trustee or Trustees, and shall fill vacancies of such Trustee or Trustees, as may be required to effect such representation. Such additional Trustees shall serve until the second succeeding Annual Meeting of the Members.

b. Each Trustee, except the additional Trustees for the customer segment, shall be a representative of a Member or a participant in a Member.

c. The Chairman, Vice Chairman, Secretary-Treasurer, the immediate Past Chairman, and the President shall, by reason of their office, be Trustees.

d. A Member, whose representative (Trustee) is elected to serve as Chairman or Vice Chairman or is the Past Chairman, must elect or appoint a replacement for that representative (Trustee), as such an elected Officer may not serve as a Member representative (Trustee) during the term of such office.

e. At least one Trustee shall be a resident of New Jersey.

ARTICLE IV
Meetings of the Board of Trustees

Section 1 — Regular Meetings of the Board — A regular meeting of the Board for such business as may come before the meeting shall be held without notice immediately following the Annual Meeting of Members at the same place as the Annual Meeting of Members. By resolution adopted at any meeting of the Board, the Board may provide for additional regular meetings that may be held without notice.

Section 2 — Special Meetings of the Board — Special meetings of the Board for any purpose or purposes may be called at any time by the Chairman or by any three Trustees. Such meetings may be held upon notice given to all Trustees not less than seven days prior to the date of the meeting. Such notice shall specify the time, date, place, and purpose or purposes of the meeting and may be given by telephone, telegraph or other electronic media, or by prepaid mail deposited in the U.S. or Canada mails.

Section 3 — Waivers of Notice of Board Meetings; and Board Meeting Adjournments — Notice of a Board meeting need not be given to any Trustee who signs a waiver of notice, in person or by proxy, whether before or after the meeting, or who attends the meeting without protesting, prior to the conclusion of the meeting, the lack of notice of such meeting.

Notice of an adjourned Board meeting need not be given if the time and place to which the meeting is adjourned are announced at the meeting at which the adjournment is taken and if the period of adjournment does not exceed ten days.

Section 4 — Action Without a Board Meeting — Any action, required or permitted to be taken at a meeting of the Board, may be taken by the Board without a meeting if all the Trustees entitled to vote on the action consent to the action in writing. The call for action without a meeting of the Board may be initiated by the Chairman or by any three Trustees, and requires written notice to all Trustees of the subject matter for action not less than seven days prior to the date on which action is to be voted. The Trustees shall receive written notice of the results within seven days of the action vote, and all written responses of the Trustees shall be filed with the minutes of the Corporation.

Any or all the Trustees may participate in a meeting of the Board or a committee by means of a conference telephone call or other communication by which all persons participating in the meeting are able to hear each other.

ARTICLE V
Officers

Section 1 — Officers — At its regular meeting, following the first Annual Meeting of Members and biennially thereafter, the Board shall elect a Chairman, a Vice Chairman, a President, a Secretary-Treasurer, an Assistant Secretary-Treasurer, and such other Officers as it shall deem necessary. The Chairman and the Vice Chairman must be Trustees prior to election to such offices. The remaining Officers need not be Trustees prior to election to such offices. The duties and authority of the Officers shall be determined from time to time by the Board. Subject to any such determination, the Officers shall have the following duties and authority:

a. The Chairman shall be Chief Executive Officer of the Corporation. He or she shall have general charge and supervision over and responsibility for the affairs of the Corporation. He or she shall preside at all meetings of the Members and at all meetings of the Board. Unless otherwise directed by the Board, all other Officers shall be subject to the authority and the supervision of the Chairman. The Chairman may enter into and execute in the name of the Corporation contracts or other instruments not in the regular course of business that are authorized, either generally or specifically, by the Board. The Chairman may delegate from time to time any or all of the aforesaid duties and authority to any other Officer.

b. The Vice Chairman shall have such duties and possess such other powers as may be delegated to him or her by the Chairman. The Vice Chairman shall act as the Chairman at such times as the Chairman may request. In the event the Chairman is unable to discharge the duties and powers of that office by reason of incapacity and during any vacancies in the office of the Chairman, the Vice Chairman shall act as Chairman until the cessation of such incapacity or the filling of such vacancy.

c. The President shall be the Chief Operating Officer of the Corporation. He or she shall be responsible for the day-to-day ongoing activities of the Corporation and shall have such other duties as may be delegated or assigned to him or her by the Chairman.

d. The Secretary-Treasurer shall have custody of the funds and securities of the Corporation; shall keep or cause to be kept regular books of account for the Corporation; shall cause notices of all meetings to be served as prescribed in these Bylaws; shall keep or cause to be kept the minutes of all meetings of the Members and the Board; and shall have charge of the seal of the Corporation. The Secretary-Treasurer shall perform such other duties and possess such other powers as are incident to his or her office or as shall be assigned to him or her by the Chairman or the Board.

e. The Assistant Secretary-Treasurer shall have such duties and possess such other powers as may be delegated to him or her by the Chairman, the Secretary-Treasurer, or the Board.

ARTICLE VI
Committees

Section 1 — Committees — There shall be an Executive Committee and such other committees and task forces as the Board may appoint as it deems necessary to carry out the purposes of the Corporation.

The Executive Committee shall be comprised of the Chairman, Vice Chairman, immediate Past Chairman, President, Secretary-Treasurer, and one additional Member-at-Large Trustee, who is a representative (Trustee) of a Member and who shall be selected by the Chairman. Between meetings of the Board, the Executive Committee shall have and may exercise all the powers of the Board in the management of the business and affairs of the Corporation, including the employment of and the fixing of salaries (including bonuses) for management personnel to conduct the business and affairs, provided that the Executive Committee shall not make, alter, or repeal any Bylaw, resolve to amend the Certificate of Incorporation, elect Trustees to fill vacancies, elect or appoint any Officers, or amend or repeal any resolution of the Board. A majority of the Executive Committee shall constitute a quorum for the transaction of business.

The Executive Committee shall keep minutes of its meetings, which shall be submitted at the next meeting of the Board at which a quorum is present and any action taken by the Board in respect thereto shall be entered in the minutes of the Board. Meetings of the Executive Committee may be held between meetings of the Board, and shall be subject to the call of the Chairman on such notice as he or she may deem reasonable. The Chairman may call upon any other Trustee to act as a member of the Executive Committee in the place of any absent member of the Executive Committee. All other committees and task forces shall have such duties as determined by the Board.

ARTICLE VII
Observers of the Board of Trustees

Section 1 — Observers — At each regular meeting at which Officers are elected, the Board may designate and invite such Observers permitted under Article EIGHTH of the Certificate of Incorporation as it shall deem appropriate. The term of each such Observer shall be two years. Such Observers may be permitted to participate in the meetings of the Board and of any committee the Board may deem appropriate, but in no event shall an Observer have the power to vote on any matter. No Observer shall be considered a Trustee, Member, or Affiliate Member of the Corporation. This provision is not a limitation of the power of the Board to otherwise act pursuant to Article EIGHTH of the Certificate of Incorporation.

ARTICLE VIII
Quorums and Voting

Section 1 — Quorums and Voting — The quorum necessary for the transaction of business at meetings of the Board, or at meetings of the Members, shall be a majority of those Trustees or Members entitled to be present at the respective meetings. Actions shall be approved upon receipt of the affirmative vote of a majority of those present and entitled to vote at any meeting in which a quorum is present.

ARTICLE IX
Fiscal Matters

Section 1 — Expenses — The expenses of each Trustee, each member of a committee or task force, the Secretary-Treasurer and the Assistant Secretary-Treasurer, unless employed to work full time on the affairs of the Corporation, shall be borne by the party by whom he or she is regularly employed, or the Member or Affiliate Member of which such party is a representative or in which such party is a participant.

Administrative expenses of the Corporation shall be authorized by the Board through the adoption of an annual budget at a meeting duly called for that purpose or at a regular meeting of the Board. Fifty percent of such administrative expenses in each year shall be borne by the Members and Affiliate Members in proportion to the total actual net energy for load of the reporting electric utility systems within their Regional boundaries for the year preceding the previous calendar year, and the remaining fifty percent of such expenses shall be borne by the Members and Affiliate Members in equal shares. Each Member's or Affiliate Member's net energy for load shall be the value reported in the NERC annual Electricity Supply & Demand report. The Board may waive any portion of the assessment or establish a minimum (or lesser) assessment for Affiliate Members.

Section 2 — Withdrawal of Members — Upon thirty days' written notice to the Board, any Member or Affiliate Member may withdraw from membership provided, however, any such withdrawing Member or Affiliate Member shall remain liable for all expenses to be borne by such Member or Affiliate Member as set forth in ~~Section 15~~ Article IX, Section 1 to the extent incurred to the effective date of such withdrawal.

Section 3 — Dissolution — Upon dissolution of the Corporation, in accordance with paragraph NINTH of the Certificate of Incorporation, the assets shall be distributed to the Member organizations of the Corporation, to the extent consistent with Section 501(c) (6) of the Internal Revenue Code, in proportion to the amounts contributed by such Members.

ARTICLE X
Amendments to the Bylaws

Section 1 — Amendments to the Bylaws — These Bylaws may be altered, amended, or repealed by the Members or the Board by a two-thirds vote at respective meetings of the Members or the Board at which a quorum of the Members or the Board entitled to vote are present. Written notice of the subject matter of the proposed changes to the Bylaws shall be provided, as appropriate, to the Members not less than ten nor more than sixty days prior to the date of the meeting of Members, or to the Trustees at a previous meeting of the Board.

Any Bylaw adopted, amended, or repealed by the Members may be amended or repealed by the Board, unless the resolution of the Members adopting such Bylaw expressly reserves the right to amend or repeal it to the Members.

ARTICLE XI
General

Section 1 — Indemnification — The Corporation shall indemnify its Officers and Trustees to the full extent from time to time permitted by the New Jersey Nonprofit Corporation Act and other law. Such right of indemnification shall inure to the benefit of the legal representative of any such person. The foregoing indemnification shall be in addition to, and not in restriction or limitation of, any privilege or power that the Corporation may have with respect to the indemnification or reimbursement of its Trustees, Officers, or employees.

Section 2 — Parliamentary Rules — *Robert's Rules of Order Newly Revised*, 1990 edition, shall apply in all cases to which they are applicable in the absence of specific provisions in these Bylaws.

Exhibit 2

By Facsimile

August 26, 1997

<u>REGIONAL COUNCIL CHAIRMEN</u>

Anthony F. Earley, Jr.	James M. Ashley
Mike Greene	John E. Deegan
Paul J. Evanson	Fred D. Williams
P.R.H. Landrieu	James J. Jura
Paul D. McCoy	Jan B. Packwood

Gentlemen:

<u>Special Notice</u>

This is notice to the Members of NERC that pursuant to Article II, Section 2 of the NERC Bylaws, Chairman Erle Nye has called a special Meeting of the Members to be convened on September 15, 1997 at 4 p.m. at the Radisson Plaza Hotel, Minneapolis, Minnesota in conjunction with the September 15–16, 1997 Board of Trustees meeting.

The purpose of the special Meeting of Members is to address and approve proposed changes to the NERC Bylaws that would add customers (end-use) to the industry segments of the electric industry from which at least two Trustees are required. These purposes will be further detailed in the Board's agenda background material scheduled to be mailed August 29, 1997.

Sincerely,

Michehl R. Gent

cc: Board of Trustees
Board Observers
Technical Steering Committee
Regional Managers

North American Electric Reliability Council
Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5731

BOARD OF TRUSTEES MEETING HIGHLIGHTS

May 5–6, 1997 — Danvers, Massachusetts

Future Role of NERC Task Force — II

NERC Reliability Standards — The Board approved the concept of a new process for developing and approving NERC reliability standards that will provide the opportunity for broad input from all electric market participants and affected parties, and final approval of new or revised standards by a 2/3 majority vote of the NERC Trustees. The details of this new process will be presented to the Board for approval at its September 1997 meeting.

Representation on NERC Board and Committees — The Board approved five "intent of the Board" resolutions to address the issue of "balance" on the NERC Board and Committees. In summary, these resolutions: 1) reaffirmed NERC's intent to assure representation and voting rights of all electric industry sectors on its Board and Committees; 2) approved adding two seats to the Board and Committees for representation of the "end-use" customer sector; 3) committed to work to assure that NERC will not be dominated by any broad single category of the industry sectors; 4) directed the Operating Committee to make its membership like the Board — two representatives per Region plus the required additional sector representatives; and 5) state that NERC expects the Regional Councils to assure that they will not be dominated by any broad single category of the industry sectors.

Reliability Management Compact — The Board agreed to request the Regional Councils and other Board members to provide comments to the Future Role of NERC Task Force by August 1 on the Straw Man proposal for an Electric Industry Mandatory Reliability Management Compact, as well as suggest alternative approaches for enforcement measures to ensure compliance with NERC reliability standards.

Review of NERC Management Structure — The Board approved hiring an independent consultant to facilitate a "Blue Ribbon Panel" of outside experts to perform a study, of six to eight months duration, to recommend a new structure for NERC that could be put in place in a timely fashion. This study will thoroughly consider the future role of the Regional Councils and their relationship to NERC. The Future Role of NERC Task Force will approve the final study scope and oversee its progress. A final report will be made to the Board in January 1998.

1997 Summer Assessment

The Board was briefed on the results of the *1997 Summer Assessment* conducted by the Reliability Assessment Subcommittee. The Subcommittee is focusing on potential supply adequacy problems in New England and MAIN due to nuclear unit outages and monitoring the progress and results of studies in WSCC for uprating the Pacific Intertie.

Phone 609-452-8060 ■ Fax 609-452-9550 ■ BBS 609-452-7669

Strategic Initiatives for NERC

Security Process — The Board was briefed on the status of the Security Process Initiative, including the establishment of 22 Security Coordinators, review of Regional Security Plans, the development of an Interregional Security Network, development and adoption of a Data Confidentiality Agreement, and a Transmission Loading Relief procedure. The Board agreed that maintaining the security of the interconnected bulk electric systems was the first priority in developing and implementing Transmission Loading Relief.

Interconnected Operations Services — The Board accepted the final report of the Interconnected Operations Services Working Group and the overall plan for incorporating Interconnected Operations Services into NERC Policies.

Other Strategic Initiatives — The Board also heard status reports on NERC's Initiatives to develop more clearly defined, uniform, and specific Operating and Planning Policies and Standards; continuing work on NERC operator certification and training course accreditation programs; and various activities related to Transmission Market and Security Initiatives.

Operating Committee Organization Document

The Board approved revisions to the *Operating Committee Organization and Procedures Document* which: restructured the OC Executive Committee, eliminated the OC Steering Committee, and revised the method for calculating approval of a Committee motion. The Board recognizes that this Document is a work in progress and that the OC will be back with further changes at the Board's next meeting to reflect the change in Regional representation agreed to by the Board.

New Officers and Additional Trustees Elected

The Board elected new officers and additional Trustees for two-year terms through May 1999. NERC's new Chairman is Erle Nye, Chairman of the Board and Chief Executive of TU Electric, replacing Richard J. Grossi, Chairman and Chief Executive Officer of The United Illuminating Company, who will remain a member of the Executive Committee. Other officers and additional Trustees elected are:

Officers

Vice Chairman — Gary L. Neale, Northern Indiana Public Service Company
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Jacques Régis, Transmission, Hydro-Québec

Engineering Committee Leadership Changes

NERC Chairman Grossi named Garey C. Rozier, Director of Bulk Power Supply, Southern Wholesale Energy, Southern Company Services, Inc., as the new Chairman of NERC's Engineering Committee, replacing Raymond M. Maliszewski, Senior Vice President-System Planning, American Electric Power; and Harlow R. Peterson, Consultant Planning Analyst, Salt River Project, as Vice Chairman.

Nominating Committee Report

At its May 5–6, 1997 meeting, the Board of Trustees approved adding two seats to the Board and Committees for representation of the customer (end-use) sector. Following the meeting, NERC President Michehl R. Gent invited the Regions and others to submit names of candidates to fill these two seats on the Board.

The Nominating Committee, consisting of Richard J. Grossi (Chairman), James E. Franklin, and Mike Greene, reviewed the list of candidates for the customer sector and recommends that the Board elect the following individuals to serve terms commencing immediately and running through the second succeeding Annual Meeting of Members (May 1999):

Vann E. Prater
Director, Electricity Affairs & Procurement
Amoco Exploration and Production Sector

Sonny Popowsky
Pennsylvania Consumer Advocate and
President, National Association of State Utility Consumer Advocates

The Nominating Committee further recommends that the Board invite the Electricity Consumers Resource Council (ELCON) and the National Association of State Utility Consumer Advocates (NASUCA), both of which qualify as "... national organizations whose interests and activities are concerned with bulk electric supply ...", as specified in Article EIGHTH of the NERC Certificate of Incorporation, to each designate an individual to observe meetings of the Board.

Action: Elect new Trustees and invite new Observers as recommended by the Nominating Committee.

North American Electric Reliability Council
Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5731

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NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

Agenda Item 5
BOT Meeting
September 15–16, 1997

TREASURER'S REPORT AND BUDGET COMPARISON
Comparison of Actual and Budgeted Expenses for the Period 1/1/97–7/31/97

	Year-to-Date			End-of-Year		
	Actual	Budgeted	Over Under (-)	Projected	Budgeted	Over Under (-)
Income						
Rental	$ 4,595	$ 4,200	$ 395	$ 8,415	$ 7,700	$ 715
Copying	63	90	-27	174	250	-76
Reports	8,349	8,865	-516	29,039	31,300	-2,261
Services & Software	43,644	43,385	259	82,213	80,500	1,713
Internet	36,630	6,185	30,445	59,227	10,000	49,227
Interest	27,930	17,830	10,100	46,996	30,000	16,996
Total Income	121,211	80,555	40,656	226,064	159,750	66,314
Expenses						
Salaries	1,136,408	998,025	138,383	1,829,907	1,607,065	222,842
Employee Costs	189,557	154,036	35,521	289,157	243,500	45,657
Retirement & Savings Plans	32,075	31,400	675	77,869	75,880	1,989
Services	127,597	111,577	16,020	298,924	255,500	43,424
Rent & Improvements	129,807	110,300	19,507	235,464	204,006	31,458
Office Costs	109,554	108,455	1,099	227,129	231,785	-4,656
Furniture & Equipment	28,556	3,960	24,596	33,591	4,500	29,091
Report Expenses	28,013	32,990	-4,977	87,335	100,790	-13,455
Computer	74,569	56,885	17,684	114,960	87,500	27,460
Travel & Meetings	203,466	145,967	57,499	459,841	366,500	93,341
Programs	5,287	2,375	2,912	4,902	23,000	-18,098
Total Expenses	2,064,889	1,755,970	308,919	3,659,079	3,200,026	459,053
Net Expenses	$ 1,943,678	$ 1,675,415	$ 268,263	$ 3,433,015	$ 3,040,276	$ 392,739

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

SPECIAL BUDGET COMPARISON
1/1/97–7/31/97

	Budget	**Year-to-date Actual**	**Projected**
Certification/Accreditation	$ 280,000	$ 114,003	$ 294,021
Transmission Management	345,000	37,653	185,725
Interregional Security Network	220,000	52,759	140,862
Standards	210,000	86,888	139,013
Blackout Response	270,000	417	15,000
Reorganization	175,000	40,945	387,812
	$1,500,000	$332,665	$1,162,433

Note: Not the same as in Budget Table 1 because $300,000 Special Project funds approved in September 1996 are included in original Treasurer's Report. This will be changed for next Board meeting.

Agenda Item 6
BOT Meeting
September 15–16, 1997

Engineering Committee Report

The Engineering Committee met on July 8–9, 1997 in Québec City, Québec, Canada. The highlights of that meeting along with some follow-on activities are summarized below.

Organizational Structure of the Engineering Committee Document

The Engineering Committee (EC) unanimously approved revisions to its September 1996 *Organizational Structure of the Engineering Committee* document to accommodate an expanded membership that includes two end-use customer representatives, changes in terminology for consistency with the Board, and reference to the new Electric Power Supply Association of independent power producers. This update is consistent with the Board's May 1997 resolution that two end-use customer representatives should be added to the NERC Board and Committees. The EC-approved Organizational Structure document is on the agenda as Item 8a for Board approval at this meeting.

Interim NERC Planning Standards

The EC approved the draft June 20, 1997 *NERC Planning Standards* report, prepared by its Reliability Criteria Subcommittee, as an interim NERC reference document. This document establishes Standards and defines in terms of associated measurements the required actions or system performance necessary to comply with the Standards. It also provides guides that describe good planning practices and considerations.

As an interim document, it is intended that the Regions and all impacted parties develop implementation plans and thoroughly review the interim Standards to support the finalization of the Standards. This EC-approved interim document will be revisited when an implementation plan and schedule as well as procedures for compliance review and enforcement are complete. It is on the agenda at this meeting under Item 12b for Board approval as an interim NERC Planning Standards document.

The EC's Standards and Compliance Task Force (formerly the Standards and Measurement Task Force) was assigned to address compliance and enforcement issues associated with the interim Planning Standards document. This effort will parallel the Operating Committee's (OC) effort through its Compliance Subcommittee to address compliance and enforcement issues associated with NERC's Operating Policies and Standards. The Technical Steering Committee will evaluate at a future date the merging of the compliance activities of both Committees under possibly a single NERC Compliance Committee.

"Due Process" Procedure for NERC Standards Development

The EC and OC, each in separate session, approved the draft "due process" procedure outlined at the July 8 Joint EC/OC meeting as an interim procedure for developing NERC Standards. The comments of the EC members on that interim procedure were reviewed in conjunction with OC comments for incorporation into a final draft due process procedure that will be presented under Agenda Item 12b for Board approval at this meeting.

Reliability Assessment Subcommittee

In July, the EC reviewed the Subcommittee's proposed outline for NERC's *Reliability Assessment 1997–2006* report. In mid-August, it also provided comments to the Subcommittee on the draft report. The Committee is expected to approve by mail ballot the Subcommittee's final draft report, which will be presented to the Board for approval under Agenda Item 13. The EC approved a revised scope for the Subcommittee, which will also be presented for approval under Item 13.

ATC Implementation Working Group

With minor modifications, the EC accepted the Working Group's report, which concluded that existing or planned Regional procedures for calculating available transfer capability (ATC) are in concert with the principles in NERC's June 1996 *Available Transfer Capability Definitions and Determination* report. It also addressed the Working Group's follow-on recommendations, approving several related actions pertaining to ATC for Working Group implementation. Key among these actions are:

- Expansion of the Working Group's scope giving the Working Group the lead in the effort to coordinate the necessary data exchange for near-term (next day to the next season) transmission transfer capability (TTC)/ATC calculations, and to facilitate the development of processes, tools, and infrastructures, as a team effort with the Regions, to accomplish this data exchange.
- Preparation of a progress report on the realistic expected completion date for Regional implementation of TTC/ATC methodologies and their coordination of TTC/ATC values within and among the Regions. The Regions are encouraged to complete their TTC/ATC implementation plans for the summer of 1998 (by April 1, 1998).
- Development of guidelines for assessing the commercial viability (technical usability) of the TTC/ATC values derived from the Regional methodologies. Trial assessments of the MAIN and MAPP TTC/ATC calculation methodologies will be performed to evaluate the guidelines and assessment techniques.
- Continuation of the investigation of transmission reliability margin (TRM) and capacity benefit margin (CBM) calculation methods and their impact on TTC/ATC calculations.

Load Forecasting Working Group

The Committee accepted for publication the Working Group's June 1997 draft report, *Peak Demand and Energy Projection Bandwidths: 1997–2006 Projections.*

System Dynamics Database Working Group

The Committee approved the Working Group's 1998 budget to update the system dynamics database and develop two dynamics simulation models (1997 summer and 2002 fall). Additional funds for the Working Group's recommended enhancements to the database were also approved.

Multiregional Modeling Working Group

The Committee approved the recommended ten power flow base cases to be developed by the Working Group as its 1998 effort and the associated 1998 budget.

Action: None

Agenda Item 7
BOT Meeting
September 15–16, 1997

Operating Committee Report

Actions at the July 8–9, 1997 Operating Committee (OC) meeting included:

Organization Document

The OC approved changes in its *Operating Committee Organization and Procedures* document to add two end-use customer representatives to the Committee. The NERC staff has been working with ELCON and will also contact the National Association of State Utility Consumer Advocates to suggest candidates. The two new members should be on board for the next OC meeting in November.

"Open Process" for Developing NERC Standards

The OC approved the new *Procedures for Developing NERC Standards*, which are described in more detail under a separate agenda item. The Procedures will continue to be a "work in progress" as we experiment with their various parts and pieces. Four Operating Policies are now being reviewed under these new Procedures, which are also covered under a separate agenda item. The Procedures can be found at http://www.nerc.com/standards on the NERC web site.

Security Coordinator Procedures

The Security Coordinator Subcommittee (SCS), which is made up of the 22 Security Coordinators plus eight liaison members from the Commercial Practices Working Group, is continuing its work on the Transmission Loading Relief Procedures (TLRP). More details on how the TLRP works, its successes and some problems, are covered under a separate agenda item. The OC continues to oversee the activities of the SCS.

Available Transfer Capability Determination

The OC is quite concerned that many of the Regional Councils do not coordinate their ATC calculations across the Regional interfaces. This adds confusion to the marketplace when transactions are being set up that cross Regional boundaries or which have multiregional effects. In some cases, Regions are curtailing transactions because neighboring Regions calculate a higher ATC or allow unlimited scheduling of nonfirm energy subject only to after-the-fact curtailment. The OC asked the ATC Working Group to accelerate its work on solving this problem, and expects all Regions to coordinate their ATC calculations before next summer.

Transaction Information System ("Tagging")

The OC agreed that tagging was to begin on July 1, 1997, as specified in Operating Policy 3, "Interchange," which the Regions approved on May 1. Despite many opinions that transaction tagging is needed to ensure operational security, the tagging procedure itself has been criticized as unwieldy. After hearing of many startup problems, the OC delayed the requirement to tag "next day" transactions until July 24, and transactions beginning in four or more hours until August 1.

Operator Certification and Training Course Accreditation

The OC accepted the recommendations from the System Operator Subcommittee (SOS) to implement programs to certify system operators on their knowledge of the NERC Operating Policies and the basics of interconnected systems operation, and to accredit system operator training courses. Both of these programs are described in more detail under a separate agenda item. The SOS will soon draft Operating Policies requiring that at least one NERC-certified system operator be on duty at all times in each control center, and that system operators complete the requirements of an accredited training course.

Compliance Subcommittee

With the Board's expectations for mandatory compliance with NERC Policies and Standards, the Operating Committee commissioned a study from its Compliance Task Force to develop the scope for a new Operating Committee Compliance Subcommittee. Under a separate agenda item the Operating Committee is requesting Board approval to create this new Subcommittee contingent upon receiving a final scope for approval at the January 1998 Board meeting.

Action: None

Committee Organization

a. ***Organizational Structure of the Engineering Committee*** **Document**

At its July 8–9, 1997 meeting, the Engineering Committee unanimously approved revisions to its *Organizational Structure of the Engineering Committee* document (Exhibit 1) to accommodate an expanded membership that includes two end-use customer representatives, changes in terminology for consistency with the Board, and reference to the new Electric Power Supply Association of independent power suppliers.

Action: Approve the revised *Organizational Structure of the Engineering Committee* document.

b. ***Operating Committee Organization and Procedures*** **Document**

At its July 8-9, 1997 meeting, the Operating Committee approved changes in its *Operating Committee Organization and Procedures* document (Exhibit 2) to add two end-use customer representatives to the Committee.

Action: Approve the revised *Operating Committee Organization and Procedures* document.

c. Operating Committee Compliance Subcommittee

With the Board's expectations for mandatory compliance with NERC Policies and Standards, the Operating Committee commissioned a study from its Compliance Task Force earlier this year to develop the scope for a Compliance Subcommittee. The study was to:

1. Identify who should be subject to review for compliance to NERC and Regional policies.
2. Identify penalty types and enforcement methods for noncompliance.
3. Detail the compliance review process and the participants.
4. Determine the makeup of the OC Compliance Subcommittee that would oversee mandatory compliance in North America.

The final report suggested that the Operating Committee develop a scope for a Compliance Subcommittee that would include the following general functions:

1. Administer compliance review process.
2. Develop a detailed and comprehensive compliance review process.
3. Develop general penalties for noncompliance.
4. Recommend to the NERC OC penalties for specific instances of noncompliance.
5. Provide for appeals procedure.
6. Recommend changes to NERC Policies and Standards.

The proposed Subcommittee would have representation from each Regional Council plus the industry sectors, and will report to the Operating Committee.

There are a number of issues that still need to be addressed. For instance, some Regional Councils already have compliance monitoring activities, and the Compliance Subcommittee will need to consider how these can be integrated into the NERC compliance review process. The Compliance Task Force study also suggested that the review teams retain a certain independence from NERC to ensure fair and unbiased reviews. Therefore, the scope of the proposed Subcommittee cannot be completed until the Subcommittee itself is formed with full representation so it can address these important issues.

Action: Approve creation of an OC Compliance Subcommittee contingent upon receiving a final scope for approval at the January 1998 Board meeting.

Exhibit 1

Organizational Structure

of the

Engineering Committee

Revisions
(shown in italics)
Approved by
Engineering Committee
July 8, 1997

North American Electric Reliability Council

September ~~1996~~ *1997*

CONTENTS

ORGANIZATIONAL STRUCTURE OF THE ENGINEERING COMMITTEE

PREFACE

The North American Electric Reliability Council's (NERC) mission is to promote the reliability of the electricity supply of the interconnected electric systems of North America. It does this by reviewing the past for lessons learned, monitoring the present for compliance with policies, ~~criteria,~~ standards, *principles*, and guides, and assessing the future reliability of the bulk electric systems.

NERC is a not-for-profit corporation whose owners are the Regional Electric Reliability Councils (Regional Councils). The members of these Regional Councils and the one Affiliate Council are individual electric systems from all ownership segments of the electric industry — investor-owned, federal, rural electric cooperatives, state, municipal, and provincial utilities, exempt wholesale generators (independent power producers), and power marketers. These entities account for virtually all the electricity supplied in the United States, Canada, and the northern portion of Baja California, Mexico.

The activities of NERC are directed by its Board of Trustees. The Board is comprised of about 30 electric industry executives that include the Board's officers, two representatives from each Regional Council, and others as needed to ensure at least two representatives from Canada ~~and~~, at least two representatives from each electric industry ownership segment, *and two representatives of end-use customers*.

Meetings of the Board are attended by Observers from the U.S. Department of Energy, the Federal Energy Regulatory Commission, the National Energy Board of Canada, the National Association of Regulatory Utility Commissioners, and several industry organizations — Edison Electric Institute, American Public Power Association, National Rural Electric Cooperative Association, Electric Power Research Institute, Canadian Electricity Association, and the Electric ~~Generation Association/National Independent Energy Producers.~~ *Power Supply Association.*

The technical activities of NERC are carried out by its Engineering Committee and Operating Committee. The Committees and their subgroups are comprised of managerial and technical representatives from the Regional Councils and from electric industry ownership segments, as appropriate. *Each Committee also includes two representatives of end-use customers.*

This document addresses the organizational structure of NERC's Engineering Committee. It updates ~~and supersedes~~ *the September 1996 Organizational Structure of the Engineering Committee document to include the addition of two representatives of end-use customers on the Engineering Committee, and changes for consistency in the Planning Policies, Standards, Principles, and Guides terminology. The September 1996 Organizational Structure document had previously updated* the Engineering Committee portion of NERC's January 1984 *Organizational Structure of Technical Committees* report~~. This update was necessary~~ to accommodate the Engineering Committee's expanded membership policy and new voting procedure approved at the February 1996 Engineering Committee

Approved by Engineering Committee: July 8, 1997
Approved by Board of Trustees: September __, 1997

meeting and other changes related to the Engineering Committee's mission, selection of officers, subgroups, and meetings.

I. ENGINEERING COMMITTEE MISSION

— Actively promotes the reliability of interconnected electric systems in the United States, Canada, and the northern portion of Baja California, Mexico,
— Establishes Planning Policies, ~~Procedures, and~~ *Standards,* Principles, and Guides to provide guidance to the Regional Councils, subregions, power pools, and individual systems in planning their interconnected electric systems,
— Provides a mechanism to coordinate planning and engineering activities among the Regional Councils,
— Provides a forum to facilitate resolving issues potentially critical to existing and future electric system reliability,
— Reviews Regional Council planning criteria or guides to evaluate if they are in concert with NERC Planning *Policies, Standards*, Principles, and Guides, and
— Reviews and assesses the overall reliability (adequacy and security) of the Regional Council's bulk electric systems, both existing and planned, to ensure that these systems conform to their respective Regional Council planning criteria or guides.

II. ENGINEERING COMMITTEE REPRESENTATION

Each Engineering Committee representative (member) shall be a representative of a Regional Council or a participant in a Regional Council, *except for the two end-use customer representatives*.

A. Regional Council Representation

Each Regional Council shall have two voting representatives (members) on the Engineering Committee. These representatives shall be elected or appointed by the Regional Council and shall serve for such term as each Regional Council may determine.

While not a requirement, each Regional Council is encouraged to have at least one of its representatives to the Engineering Committee serve a minimum term of four years. In addition, the terms of the two representatives from each Region should overlap, if possible, by at least one year to provide continuity.

B. Industry Segment Representation

Should the Engineering Committee's membership so selected under Section II.A at any time not include at least two representatives from Canada or not include at least two representatives of each segment of the electric industry (i.e., a) federal, b) investor-owned, c) rural electric cooperative, d) state/municipal, e) exempt wholesale generator (independent power producer), and f) power marketer), the Engineering Committee shall elect, from a slate of candidates provided for this purpose by the Engineering Committee's Nominating Task Force, additional representatives to fill such vacancies as may be required to effect such representation. Such Canada or industry segment representatives shall serve a term of two years.

The Engineering Committee shall also elect from a slate of candidates provided by the Engineering Committee's Nominating Task Force two representatives of end-use customers to serve as members of the Engineering Committee. The end-use customer representatives shall serve a term of two years.

The Regional Councils shall provide a list of candidates for the additional Canada or industry segment representatives *and the end-use customer representatives* to the Engineering Committee's Nominating Task Force for its consideration.

The Engineering Committee shall review its Canada ~~and~~, industry segment, *and end-use customer* representation whenever a Committee member is replaced or his or her term expires. The Committee Chairman shall not allow two or more consecutive Committee meetings to pass before Canada ~~and~~, industry segment, *and end-use customer* representation as described above is in place.

To the extent possible, consideration should be given to providing continuity and overlapping terms for the additional Canada and industry segment representatives *and the end-use customer representatives*.

C. Officers

The Officers of the Engineering Committee shall be a Chairman and Vice Chairman. The Chairman and Vice Chairman, by virtue of their office, are individual members of the Committee and are not Regional Council representatives to the Committee while serving as Committee Officers.

The term of Committee office is two years. The Vice Chairman succeeds to the chairmanship when the chair is left vacant for any reason. Changes of Officers take place upon the approval of the Chairman of the NERC Board of Trustees.

The Engineering Committee Chairman and Vice Chairman, by virtue of their office, are voting members of the Engineering Committee.

D. Observers

1. The immediate Past Chairman of the Engineering Committee is an ex-officio, non-voting member of the Engineering Committee.

2. The Engineering Committee may 1) designate Observers to its Committee who are representatives of the United States government and the government of Canada, and 2) invite other U.S. and Canadian federal agencies and national or international organizations, whose interests and activities are concerned with bulk electric supply, to designate an individual to observe the meetings of the Engineering Committee upon the determination by the Engineering Committee that such action would enhance the effectiveness of the Committee in attaining its mission.

   The term of each Observer shall be two years. Such Observers may be permitted to participate in the meetings of the Engineering Committee and those Committee subgroups the Committee may deem appropriate, but Observers shall not have the power to vote.

III. DUTIES OF ENGINEERING COMMITTEE OFFICERS

A. Committee Chairman

— Provide general supervision of Committee activities, and act as spokesman for the Committee at forums within and outside NERC.
— Provide for Committee meeting agendas and preside at Committee meetings.
— Serve as a member of the Technical Steering Committee.
— Attend meetings of the Board of Trustees and report to the Board on Committee activities.
— Perform other duties as assigned by the Board of Trustees.
— Establish such subcommittees, working groups, or task forces as may be directed by the Committee.
— Notify, in writing, all newly appointed representatives to existing or new subcommittees, working groups, or task forces.
— Appoint a three-member Nominating Task Force of the Engineering Committee, as appropriate.

B. Committee Vice Chairman

— Perform the duties of the Chairman in his or her absence.
— Assist the Chairman as called upon.

— Serve as a member of the Technical Steering Committee.
— Attend meetings of the Board of Trustees.

C. Immediate Past Committee Chairman

— Attend and participate in Committee meetings as an ex-officio, non-voting member.
— Assist the Chairman as called upon.

IV. ENGINEERING COMMITTEE PROCEDURES

A. Meetings

1. Three regular meetings per year of the Engineering Committee and Operating Committee shall be held concurrently, with a provision for joint meetings of the Committees as required.

2. Attendance at Engineering Committee meetings is limited to those in the NERC Committee structure, Regional Council staff, NERC staff, official Observers, and those invited by the Committee Chairman.

3. Substitute or proxy representatives may attend and vote at Engineering Committee meetings provided the absent Committee representative notifies in writing (letter or facsimile) the Committee Chairman or Vice Chairman prior to the meeting, along with the reason(s) for the substitute or proxy. The substitute or proxy representative must also be named in the correspondence.

4. Special meetings of the Engineering Committee may be called for any purpose or purposes by the Committee Chairman, or upon the request of any Committee member, the Committee Chairman will call a special meeting. Such meetings shall be called upon written notice (letter or facsimile) of the time, date, place, and purposes of the meeting given to all Committee members not less than ten (10) or more than sixty (60) calendar days prior to the date of the meeting.

5. Agendas for regular Committee meetings shall be mailed to Committee members at least two weeks prior to the meeting. Agenda items will be categorized and identified in the agenda as: Administrative, Informational, Review (for future action), and Action Required.

   Agenda background material shall be provided for all items on which Committee action is expected. Exceptions require the approval of the Committee Chairman.

Agenda material shall be provided to the NERC office according to the dates specified on the list of "Future Meetings and Agenda Input Deadline Dates" included as an exhibit in the Committee minutes.

B. Quorums and Voting

The quorum necessary to transact business at meetings of the Engineering Committee shall be a two-thirds majority of those Committee members entitled to be present and vote at the respective meetings. If voting is needed:

1. An action shall be approved upon the affirmative vote of a two-thirds majority of those Engineering Committee members present and entitled to vote at any meeting in which a quorum is present.

2. Any action required or permitted to be taken at a meeting of the Committee may be taken without a meeting if all the Committee members entitled to vote on the action approve the action by a two-thirds majority of the members entitled to vote on the action. Such action without a meeting shall be performed by mail or electronic (telephone or facsimile) ballot. The call for action without a meeting may be initiated by the Committee Chairman, or upon the request of any Committee member, the Committee Chairman will initiate the call for such action. Written notice (letter or facsimile) to the Committee members of the subject matter for action is required not less than ten (10) nor more than sixty (60) calendar days prior to the date on which action is to be voted.

   Committee members shall receive written notice (letter or facsimile) of the results of such action within ten (10) calendar days of the action vote. All responses of the Committee members shall be filed with the minutes of the Committee.

C. Selection of Officers

1. The Chairman and Vice Chairman of the Engineering Committee shall be elected by the Committee members, with the approval of the Chairman of the NERC Board of Trustees, from a slate of candidates submitted by the Committee's Nominating Task Force.

2. The Engineering Committee's Nominating Task Force shall submit its slate of Committee Officer candidates to the Engineering Committee for a vote at the first regularly scheduled Committee meeting of the year. Nominations from the floor will be accepted. The Chairman of the Board of Trustees shall take action on the Committee's selection generally at the second (May) Board meeting of the year.

3. An Engineering Committee Secretary shall be assigned from the NERC staff with the approval of the Committee Chairman. The Secretary shall not have the power to vote.

D. Subcommittees, Working Groups, and Task Forces

1. **Subcommittees** — The Engineering Committee may establish subcommittees to which certain of the Committee's broadly defined continuing functions may be assigned. Upon the formation of a subcommittee, a written scope must be submitted to the NERC Board of Trustees for approval. The subcommittee Chairman (and Vice Chairman, if appropriate) will be appointed for a two-year term by the Chairman of the Committee to which the subcommittee reports. The Chairman of a subcommittee may be reappointed for a second term only.

2. **Working Groups** — The Engineering Committee or any of its subcommittees may also delegate specific continuing functions to a working group. Upon the formation of a working group, a written scope must be submitted to the Engineering Committee for approval. The working group Chairman (or Vice Chairman, if appropriate) will be appointed for a specific term (generally two years) by the Chairman of the Engineering Committee or subcommittee to which the working group reports. The Chairman of a working group may be reappointed for a second term only. All working groups will undergo a "sunset" review by the Engineering Committee every two years.

3. **Task Forces** — The Engineering Committee or any of its subcommittees may also form a group to address a specific issue. Such a group will be known as a task force. Normally, a task force should not be constituted for more than one year. The formation of a task force, approval of its scope, and appointment and term of its Chairman (and Vice Chairman, if appropriate) are handled in the same manner as for working groups.

4. **Subgroup Representation** — The two basic forms of representation on a subcommittee, working group, or task force include:

   a. Where Regional representation is necessary, one representative will be appointed by each Regional Council. Should the subcommittee, working group, or task force so constituted not have at least one representative from Canada ~~and~~, one representative from each segment of the electric industry, *and one end-use customer representative* as defined in Section II.B above, the Chairman of the Engineering Committee or subcommittee to which the subgroup reports will invite that segment, which is not represented, to appoint a representative.

b. Where representation is based solely on individual expertise as it relates to the mission of the subcommittee, working group, or task force, without the requirement for Regional, Canada, ~~and~~ electric industry segment, *and end-use customer* representation, appointments will be made by the Chairman of the Engineering Committee or subcommittee to which the subgroup reports, after coordinating with the Chairman of the proposed subgroup, appropriate NERC and Regional Council staffs, and appropriate electric industry segment *and end-use customer* organizations.

E. General

Robert's Rules of Order Newly Revised, 1990 edition or any successor, shall apply in all cases to which they are applicable in the absence of specific provisions in this document.

V. NOMINATING TASK FORCE OF THE ENGINEERING COMMITTEE

A. Membership

The Engineering Committee shall have a Nominating Task Force, as needed, whose three members shall be appointed by the Committee Chairman. The Committee Chairman shall also appoint the Task Force Chairman from among the three Task Force members.

B. Functions

1. The Nominating Task Force shall present every two years, or as otherwise necessary, a slate of Committee Officer candidates to the Committee members for election by the Committee at the first regularly scheduled Committee meeting of the (appropriate) year.

2. The Nominating Task Force shall present, as necessary, a slate of additional Canada or other electric industry segment candidates, *or end-use customer candidates*, to the Committee for election by the Committee to meet the Committee's membership representation requirements as detailed under Section II.B.

------------------ COMPARISON OF HEADERS ------------------

-HEADER 1-
ORGANIZATIONAL STRUCTURE OF THE ENGINEERING COMMITTEE

------------------ COMPARISON OF FOOTERS ------------------

-FOOTER 1-
Approved by Engineering Committee: July ~~16, 1996~~ *8, 1997*
Approved by Board of Trustees: September ~~16, 1996~~*, 1997*

1.

Operating Committee Organization and Procedures

Subsections

The North American Electric Reliability Council s (NERC) mission is to promote the reliability of the electricity supply for North America. It does this by reviewing the past for lessons learned, monitoring the present for compliance with Policies and Standards, and assessing the future reliability of the bulk electric systems.

NERC is a not-for-profit corporation whose "owners" are the Regional Councils. The members of these Regional Councils and the one affiliate Council are individual electric systems from all ownership segments of the electricity supply industry investor-owned, federal, rural electric cooperatives, state, municipal, and provincial utilities, independent power producers, and power marketers – plus end-use customers. These entities account for virtually all the electricity supplied in the United States, Canada, and Baja California Norte, Mexico.

Add End-Use Customer members

The activities of NERC are directed by its Board of Trustees. The Board is comprised of about 30 electricity supply industry executives including the Board s officers, two representatives from each Regional Council, and others as needed to ensure at least two representatives from Canada and at least two representatives from each electricity supply industry ownership segment, and two end-use customers.

Meetings of the Board are attended by observers from the U.S. Department of Energy, the Federal Energy Regulatory Commission, the National Energy Board of Canada, the National Association of Regulatory Utility Commissioners, and several industry organizations Edison Electric Institute, American Public Power Association, National Rural Electric Cooperative Association, Electric Power Research Institute, Canadian Electricity Association, and ~~the Electric Generation Association and National Independent Energy Producers~~the Electric Power Supply Association.

The technical activities of NERC are carried out by its Engineering Committee and Operating Committee. The Committees and their subgroups are comprised of managerial and technical representatives from the Regional Councils and from electric industry ownership segments, and end-use customers as appropriate.

This document addresses the organizational structure of NERC s Operating Committee. It updates and supersedes the Operating Committee portion of NERC s January 1984 *Organizational Structure of Technical Committees* document. This update was necessary to accommodate the Operating Committee s expanded membership policy and other changes related to the Operating Committee s mission, selection of officers, subgroups, and meetings.

Operating Committee Organization

A. Mission

The Operating Committee:

1. Actively promotes the reliable operation of the interconnected electric systems in the United States, Canada, and Baja California Norte, Mexico.
2. Establishes Policies ~~and Standards~~ (Standards, Requirements, and Guides) for interconnected systems operation,
3. Monitors compliance with the established Policies, and
4. Provides a forum for dealing with interconnected systems operation issues.

B. Representation

1. **Regional Council Representation**. Each Regional Council shall appoint two representatives to serve on the Operating Committee. Certain Councils, because of geographical size or magnitude of demand, may, with the concurrence of the Operating Committee, appoint more than two representatives. Regional Council representation as of December 1, 1996 is shown on the following table:

Region	Number of OC Representatives
ECAR	3
ERCOT	2
FRCC	2
MAAC	2
MAIN	2
MAPP	2
NPCC	3
SERC	3
SPP	2
WSCC	4

2. **Industry Segment Representation**. The Operating Committee shall include at least two representatives from Canada plus at least two representatives from each segment of the electric industry:

   2.1. U.S. federal

   2.2. investor-owned

   2.3. rural electric cooperative

   2.4. state/municipal

2.5. independent power producer ~~and~~

2.6. independent (non-affiliated) power marketer, and~~.~~

2.7. end-use customer

3. **Filling industry segment vacancies.** The following procedure will be used to fill industry segment vacancies:

3.1. **Nominations from Regional Councils.** Each Regional Council will provide a list of nominees selected from its membership who have the competencies that would enhance the effectiveness of the Operating Committee in attaining its mission.

3.2. **Slate determined by Chair.** The Committee Chair shall propose a slate of candidates from this list. In selecting candidates, the Committee Chair will take into consideration the diversities of geography, experience, and viewpoint.

3.3. **Committee selects from slate.** The Committee shall select representatives from this slate to fill such vacancies for two-year terms as may be required to ensure adequate representation. Members so selected are provided membership with the intent that they provide an operating point of view from that segment of the industry.

3.3.1. **Segment representation term.** New segment representatives shall normally serve two-year terms. However, their service shall end upon change of employment to a position outside the industry segment from and for which they were selected.

3.3.2. **Authorization to replace representative.** An unfulfilled term shall be served by a replacement industry segment representative, if needed. In this case, in the interest of time, the Committee Chair shall follow the procedures in sections 3.1 and 3.2 above, and may then perform the final selection.

4. **Segment representation review.** The Committee Chair shall review industry segment representation whenever a Committee member s term ends, and select a replacement, if needed, as explained in Section 3 above. (A segment representative need not be replaced if that segment is already represented by a Regional Council member.)

4.1. The Committee Chair should not allow two or more consecutive meetings to pass before filling the absent industry segment representative position.

C. Observers

1. Designating observers. The Operating Committee shall:

1.1. Designate Observers to its Committee who are representatives of the U.S. government and the government of Canada, and

1.2. Invite other U.S. and Canadian federal agencies or national or international organizations, whose interests and activities are concerned with interconnected systems operation, to designate an individual to observe the meetings of the Committee upon the determination by the officers of the Committee that such action would enhance the effectiveness of the Committee in attaining its mission.

2. **Observer term.** The term of each Observer shall be two years. Such Observers may be permitted to participate in the meetings of the Operating Committee and those Committee subgroups the officers of the Committee may deem appropriate, but the Observer shall not have the power to vote.

D. Officers

1. **Officers.** The officers of the Committee shall include a Chair, Vice Chair, Secretary, and immediate past Chair. Officers are neither Regional Council representatives nor industry segment representatives while serving as officers.

2. **Terms.** The term of office is two years, and the normal progression is from Vice Chair to Chair. The Vice Chair succeeds to the chairmanship when the Chair is left vacant for any reason. Changes of officers take place at the beginning of the calendar year or whenever a successor is appointed.

3. **Duties of Operating Committee Officers**

3.1. **Committee Chair**

3.1.1. Provide general supervision of Committee activities and act as spokesman for the Committee. Provide leadership and set the agenda of Committee activities.

3.1.2. Administer the Committee meeting agendas and preside at the meetings.

3.1.3. Represent the Committee to the Board of Trustees and other forums as appropriate.

3.1.4. Execute decisions by the Board of Trustees and perform other duties as directed by the Board.

3.1.5. Establish such subcommittees, working groups, or task forces as may be directed by the Committee.

3.1.6. Notify in writing all newly appointed representatives to existing or new subcommittees, working groups, or task forces of their appointment.

3.1.7. Propose a slate of candidates to fill industry segment representative vacancies and appoint Committee observers, as appropriate.

3.1.8. Appoint a three-member Nominating Committee at the regular summer meeting of the second year of the Chair's term.

3.2. **Committee Vice Chair**

3.2.1. Perform the duties of the Chair in his or her absence.

3.2.2. Assist the Chair as called upon.

3.2.3. Attend meetings of the Board of Trustees.

3.3. **Committee Past Chair**

3.3.1. Assist the Chair as called upon.

3.3.2. Serve as a non-voting member of the Operating Committee.

3.4. **Committee Secretary**

3.4.1. Prepare the minutes of the Committee meetings.

3.4.2. Maintain the Committee records.

3.4.3. Assist the Chair and Vice Chair as called upon.

E. Operating Committee Executive Committee

1. **Executive Committee members.** The Operating Committee Executive Committee shall consist of the Chair, Vice Chair, Secretary, and Past Chair.

1.1. **Duties.** The Executive Committee will assist the Chair in:

1.1.1. Coordinating subcommittee activities

1.1.2. Preparing the Operating Committee meeting agenda

1.1.3. Suggesting items for Operating Committee review

1.1.4. Responding to urgent matters

1.1.5. Preparing reports to the Board of Trustees

2. **Authority.** The Executive Committee may exercise all the powers of the Committee between meetings of the Committee. Any action taken by the Executive Committee will be submitted for ratification at the next meeting of the full Operating Committee.

3. **Meetings.** The Chair may call for a meeting of the Executive Committee at any time. The Chair may also invite others to meetings of the Executive Committee as needed.

Operating Committee Procedures

A. Meetings

1. **Parliamentary Procedure.** The latest edition of *Robert's Rules of Order* shall apply in all cases to which they are applicable in the absence of specific provisions in this document.

2. **Meetings.** The Operating Committee shall hold three regular meetings each year, concurrently with the Engineering Committee, with a provision for joint meetings of the two Committees as required.

   2.1. **Special meetings.** The Operating Committee Chair may call for special meetings of the Committee as needed.

3. **Attendance.** Attendance at the Operating Committee meetings is limited to those in the NERC Committee structure, Regional Council staff, NERC staff, official Observers, and those invited by the Chairman.

4. **Substitutes.** Upon written notification from the Regional Council or industry segment representative to the Secretary, a Region or industry segment representative may send a substitute representative to attend in place of its regular representative. Substitutes are entitled to participate in meeting discussions and vote. ~~A substitute is entitled to vote only if the Region submits a proxy, over the signature of the Committee member being represented, to the Committee Chair.~~

   4.1. **Proxy voting.** Proxy voting is not allowed. *(Robert's Rules, Section 44. Voting Procedures.)*

Fix an incorrect interpretation of a "proxy." A proxy permits a person to vote on behalf of another person. That is, a proxy would allow a representative to have more than one vote.

B. Voting

1. **Quorum.** The quorum necessary to transact business at meetings of the Committees shall be a majority of the Committee voting representatives and proxies entitled to be present. *(Robert's Rules, Section 3, Basic Provisions and Procedures.)*

2. **Two-thirds majority to carry an issue.** In the Operating Committee, a motion will be carried by at least a two-thirds majority of the votes cast[1] by the representatives at any meeting in which a quorum is present. *(Roberts's Rules, Section 43, Voting.)*

   2.1. **Officers.** The Chair, Vice Chair, Secretary, and Past Chair are not entitled to vote.

   2.2. **Voting by mail.** The Committee may vote by mail (including e-mail) on any motion that has been *Postponed Until A Certain Time*. The Committee can postpone the vote on a pending motion to an e-mail vote as long as the debate has been completed and the Committee is ready to vote. For example, the OC may have a pending motion to change a Standard or Requirement, but decides that it cannot vote on the motion until the Committee members debate the subject within their Regions. Assuming the debate among the

[1] The number of votes cast equals the number of affirmative votes plus the number of negative votes.

Committee is complete, the motion can be *Postponed to a Certain Time* at which it will then be voted by e-mail. It would then be approved with a two-thirds majority of the total e-mail votes cast.

~~2.3. **Operating Policies.** In the case of voting on the adoption of amended or new Operating Policies, the affirmative vote of at least two-thirds of the Regions is required.~~

Policies to be approved by OC and Board through "Due Process."

C. Selection of Officers

1. **Chair and Vice Chair.** The Chair and Vice Chair of the Operating Committee are appointed by the Chair of the Board of Trustees at the Board s September meeting from a slate of candidates recommended by the Committee s Nominating Committee and approved by the Operating Committee.

2. **Secretary.** A Committee Secretary from the NERC staff will be appointed by the Committee s officers and will not have the power to vote.

D. Formation of Subcommittees, Working Groups, and Task Forces

1. **Subcommittees.** The Operating Committee may establish subcommittees to which certain of the Committee s broadly defined continuing functions may be assigned. The Operating Committee will draft the initial scope statement for the subcommittee. Upon the formation of a subcommittee, a written scope must be submitted to the Board of Trustees for approval. The subcommittee chair (and vice chair, if appropriate) will be appointed for a two-year term by the Operating Committee Chair.

2. **Working Groups.** The Operating Committee or subcommittee may also delegate specific continuing functions to a working group. A working group has a narrower scope than a subcommittee. The Operating Committee will draft the initial scope for the working group. The working group chair (or vice chair, if appropriate) will be appointed for a specific term (generally two years) by the Operating Committee Chair.

3. **Task Forces.** Should the Operating Committee or subcommittee desire to form a group to address a specific issue, that group will be known as a task force. Normally, a task force should be constituted for no more than one year. The formation of a task force, development of its scope, and appointment and term of its chair (and vice chair, if appropriate) are handled in the same manner as for working groups.

4. **Forms of representation**. There are two basic forms of representation on a subcommittee, working group, or task force:

   4.1. **Regional representation.** Where Regional representation is necessary, one representative will be appointed by each Regional Council. Should the working group or task force so constituted not have at least one representative from Canada and each segment of the industry ~~as defined in Section II. B above~~, the chair of the parent Committee or subcommittee to which the subgroup reports will invite that segment not represented to appoint a representative. Regional nominations of industry segment representatives as specified in Sections 3.1 and 3.2 are required for selection of industry segment representatives for subcommittees.

4.2. **Individual expertise.** Where representation is based solely on individual expertise as it relates to the mission of the subcommittee, working group, or task force, without the requirement for Regional and electric industry segment representation, appointments will be made by the chair of the parent Committee or subcommittee to which the subgroup reports, after coordinating with the chair of the proposed subgroup and appropriate NERC and Regional Council staffs.

5. **Sunset review.** At least every two years, every subcommittee, working group, and task force must submit, to the Operating Committee, a recommendation to continue, change its scope, or dissolve.

Future Role of NERC Task Force — II

The Future Role of NERC Task Force — II was created by the Board in January 1996 to review NERC's future role, responsibilities, and organizational structure in light of the rapid changes taking place in the industry. In January 1997, the Board directed the Task Force to oversee the implementation of the "Next Steps" identified in the Options to Ensure Compliance report and provide direction to the Committees and staff, as appropriate, and regularly report progress to the Board.

a. Electric Reliability Panel

The Florida Conflict Resolution Consortium (FCRC), the consultant hired by NERC to facilitate the Electric Reliability (Blue Ribbon) Panel study of the future of NERC, is well along in its preparations for the Panel's first meeting on September 20–21, 1997 in Toronto, Ontario, Canada. Only one Panel member, representing state regulatory interests, remains to be named. This selection is imminent.

Robert M. Jones and Stuart Langton, the FCRC principals heading up the study, met with the Future Role of NERC Task Force — II to review the status of the project. Task Force members provided input on key trends that could influence the future development of the electricity industry as well as on the ten questions that make up the Reliability Issues Review Framework used as a guide in gathering input for the study. The consultants met the following day with the Regional Managers for a similar discussion.

FCRC is interviewing a broad cross section of individuals both inside and outside the industry to gather their perspectives on electric supply reliability. Included in this list are the Regional Chairmen and other Trustees, trade association representatives, several members of the DOE Electric System Reliability Task Force, FERC Commissioners, DOE staff, and other key electric market participants.

The three Panel meetings will be open to the public to attend and observe the Panel's deliberations and to participate in open dialog sessions following each formal meeting. The Panel meeting dates and locations are: September 20–21 in Toronto, Ontario, Canada; October 25–26 in San Francisco, California; and December 6–7 in Austin, Texas.

The Task Force will continue to closely follow the progress of this study and keep the Board informed. The project is very ambitious considering that the Panel will only meet as a group three times for a total of six days. Once NERC receives the Panel's recommendations in January, there may be a need for broad discussion, both inside and outside the industry, to achieve buy-in by all stakeholders. Gary Neale, Task Force Chairman, will address the Board's questions.

The following items are attached to keep the Board informed of the progress of this study:

- Press Release – August 18, 1997 (Exhibit 1)
- Panel Roster (Exhibit 2)
- Study Synopsis (Exhibit 3)
- Meeting Objectives for the Panel's September 20–21, 1997 Meeting (Exhibit 4)

Action: None

b. Mandatory Compliance Initiatives

One of the recommended "Next Steps" identified in the Options to Ensure Compliance report was the development of an Industry Compact to "... acknowledge a voluntary transition to mandatory compliance and separation of reliability management and commercial functions." The NERC Reliability Compliance Team developed a straw man proposal for an Electric Industry Mandatory Reliability Management Compact that the Future Role of NERC Task Force — II presented to the Board in May 1997. The Board agreed to request the Regional Councils and other Board members to provide comments on the straw man proposal to the Task Force, along with any other suggested approaches for enforcement measures to ensure compliance with NERC reliability standards.

Six Regions submitted written comments and several others commented informally. The Task Force discussed the wide range of opinions expressed on the concept of developing an Industry Compact and agreed that it was not practical to present anything to the Board for approval at this time. The Task Force did agree that the Compliance Team, as the original authors of the straw man Industry Compact, should actively participate in WSCC's effort to develop a reliability compact and report back to the Task Force and the Electric Reliability Panel on the applicability of WSCC's approach to NERC and the other Regional Councils.

Another of the "Next Steps" that relates closely to the Industry Compact is the development of a system of enforcement measures, which the industry would review and approve and make part of contractual agreements. The recommendation in the Options to Ensure Compliance report called for the creation of a group to define a system of enforcement measures in which the consequence of noncompliance with reliability standards would increase with the severity of the noncompliance. As a first step in this process, the Task Force agreed that each Region should submit a written report to the Board by January 1998 explaining what the Region is doing (or planning to do) to implement mandatory compliance within their Region as required in the NERC Bylaws. The Task Force will review these responses to determine how to move forward on this initiative.

The Engineering Committee and Operating Committee are also working on other aspects of compliance monitoring and enforcement, and the Board will hear reports from both at this meeting. The Operating Committee, on recommendation of its Compliance Task Force, is seeking Board approval to form an Operating Committee Compliance Subcommittee to:

- develop and administer a compliance review process,
- develop penalties for noncompliance,
- provide an appeals procedure, and
- recommend changes to the Operating Policies and Standards.

The Compliance Task Force believes that the role of the Operating Committee's Compliance Subcommittee may at some point be broadened to include compliance reviews of Planning Standards as well as Operating Standards, and at that time the Subcommittee could become a full Committee of the Board.

The Engineering Committee's Standards and Compliance Task Force is overseeing the development of new NERC Planning Standards as well as the procedures for monitoring and enforcing compliance with them. The Engineering Committee is seeking Board approval of an extensive set of Interim NERC Planning Standards at this meeting. The Operating Committee is farther along in the Standards-Compliance Monitoring-Enforcement process because an established set of Operating Policies and Standards has existed for some time. The Engineering Committee, on the other hand, must first develop and approve new Planning Standards before it can devise accompanying compliance monitoring and enforcement measures.

Action: Request each Region to submit a written report to the Board by January 1998 explaining what the Region is doing (or planning to do) to implement mandatory compliance as required in the NERC Bylaws.

c. Alternate Funding Approach for NERC

At the May 1997 Board meeting, the Budget Committee presented a preliminary Budget for 1998. The discussion that followed raised questions about the way in which the NERC Assessment was allocated to the Regions and whether a new funding approach was needed for reliability management services or functions NERC is expected to perform.

Gary Neale, Task Force Chairman, requested the NERC Reliability Compliance Team to develop several alternative ways for the funding of NERC (or reliability functions), which the Task Force reviewed at its June 11, 1997 meeting. The Task Force agreed that the Team should develop a specific recommended straw man for funding that identifies information services and reliability management services and the recipients of these services.

At the August 18, 1997 Task Force meeting, the Team reported that it had reached unanimous agreement on a recommended funding approach that would prorate 75% of the annual NERC Budget between all members based on end-use energy and the other 25% shared equally by all members. This approach is independent of voting structure and would work with any model of NERC's future members. The Task Force members agreed that the ability to recover the costs of assuring reliability from those who benefit from a reliable system is key to a new funding approach. The Task Force also generally agreed with the Supporting Principles and Assumptions as set out in the Team's report (Exhibit 5), but recognized that a mechanism was needed for assessing all end-use electricity customers a reliability service "fee" before such a funding approach could be implemented.

Chairman Neale asked the Compliance Team to work closely with WSCC, which is also working on how to recover the costs of reliability from all consumers and market participants, to develop an approach that was consistent with the Supporting Principles and Assumptions and which could be applied throughout North America and report back to the Task Force. The Team's report and follow-on recommendations will also be shared with the Electric Reliability Panel as background for their study.

The Task Force will wait until January 1998 to make any specific recommendations.

Action: None

North American
Electric
Reliability
Council

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Exhibit 1

FOR IMMEDIATE RELEASE

Electric Reliability Panel to Meet

A Panel of experts chosen to help define the future course for ensuring the reliability of North America's interconnected electric grids has scheduled its first meeting for September 20–21, 1997 in Toronto.

Rapid changes in the electric industry, spurred by emerging competition and utility deregulation, prompted the Panel's creation by the North American Electric Reliability Council (NERC).

The Panel's job is to draft recommendations for the best management framework and division of effort and responsibilities for setting, overseeing, and implementing policies and standards to ensure the continued reliability of interconnected bulk electric systems throughout North America.

"It's time for a first rate, objective, thorough examination of the technical and institutional issues surrounding the continued reliability of North America's interconnected electric systems," said Michehl R. Gent, NERC's president. "We've appointed a Panel of individuals known for their independence and insight to do that job and hired an outside firm to facilitate this critically important study."

Members of the Electric Reliability Panel include former Federal Energy Regulatory Commission member Charles Stalon, who is serving as the Panel's organizing chair, and leaders from business, government, academia, and industry concerned with balancing a rapidly changing and competitive electric industry with the reliable performance of North America's electric grids.

To staff the Panel and design and promote an independent, credible, facilitated study, NERC turned to the Florida Conflict Resolution Consortium. The Consortium specializes in applying facilitation and consensus-building techniques to public policy matters and in helping settle environmental, land-use, and growth-related conflicts.

The September meeting will include a review and analysis of background materials, expert briefings, and identification and discussion of scenarios and options regarding the future organization and management of a reliability assurance framework designed to meet the needs of a more competitive electric industry. The Panel will have two additional two-day public meetings in October and December and deliver a final report to NERC's Board of Trustees at its January 1998 meeting.

The report is to reflect the Panel's review and evaluation of the changes affecting the electric industry and make recommendations on the mission, functions, and governance structure that can ensure reliability in the future. Industry changes include wholesale electric markets being opened to competition, energy companies merging, and new competitors entering the market.

The Panel is to consider:

- how reliability matters and commercial needs should be addressed and balanced within the industry;
- the appropriate roles and responsibilities of public and private interests;
- how different scenarios for the industry's future may shape reliability functions and responsibilities within the industry;
- how those responsible for ensuring reliability should be funded; and
- in what ways should the present regional system involving ten Regional Reliability Councils and NERC be preserved or changed?

Besides **Dr. Stalon**, members of the Panel include **Richard E. Balzhiser**, President Emeritus, Electric Power Research Institute; **Richard Drouin**, former CEO of Hydro-Québec and Vice Chairman, Morgan Stanley Canada; **George L. Edwards**, President and Chief Executive Officer, Alliance for Telecommunications Industry Solutions; **Victor Gilinsky**, former Commissioner with the Nuclear Regulatory Commission; **Leonard S. Hyman**, Senior Industry Advisor, Smith Barney; **Hazel O'Leary**, former Secretary, U.S. Department of Energy, **Alex Radin**, former Executive Director of American Public Power Association and President, Radin & Associates, Inc.; **Dr. Vernon L. Smith**, Regents' Professor of Economics and Director of Research and Education at the University of Arizona's Economic Science Laboratory; and **William H. Clagett**, former Administrator of Western Area Power Administration and former Chairman of NERC and the Western Systems Coordinating Council. A representative of the state regulatory community will also be added to the Panel, and **Mary L. Schapiro**, President, National Association of Securities Dealers Regulation, Inc. will work with the Panel to provide first-hand experience on self-regulating organizations.

Panel meetings are open to the public. Persons wishing to attend any of the meetings should notify the Florida Conflict Resolution Consortium well in advance so that sufficient seating may be made available. In the case of the first meeting at the Toronto Marriott at Eaton Centre, notification should be made by September 1, 1997 to Cathy Nipper at the Florida Conflict Resolution Consortium, phone: 904-644-6320, fax: 904-644-4968. Those interested in providing information to the Panel should forward written comments to Robert Jones, the Panel facilitator, at the Consortium's office or by e-mail: flacrc@mailer.fsu.edu.

Several Panel members and Consortium representatives will be available following each meeting for observers to offer information, ideas, and suggestions for the Panel to consider.

For more information on the Panel and its work, point your web browser to: www.nerc.com/~blue/scope. This site will carry reports on the Panel's progress following each meeting. You may also contact Gene Gorzelnik at NERC (609-452-8060).

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*Advisor to Panel

September 9, 1997

Exhibit 3

North American Electric Reliability Council
Blue Ribbon Reliability Panel
Synopsis

I. Background and Context

NERC was formed in 1968 to promote the reliability of the bulk electricity supply for North America in the aftermath of the November 9, 1965 blackout that affected the Northeastern United States and Ontario, Canada. NERC is a not-for-profit corporation whose owners and members are ten Regional Reliability Councils. These Councils and their members account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico and come from all segments of the electricity supply industry: investor-owned, federal, rural electric cooperatives, state, municipal, and provincial utilities, independent power producers, and power marketers. NERC and the Regional Councils have been undergoing significant changes in their membership, processes, and organizational structures that are designed to make them more effective in a restructured electricity industry. Currently, over 40% of the members of the Regional Councils are other than "traditional" electric utilities.

Historically, NERC and the Regional Councils have been responsible for the reliability of the bulk electric system. NERC establishes national reliability policies, standards, criteria, principles, and guides for operating and planning interconnected electric systems. Regional Councils establish more detailed standards to reflect conditions within their Region.

In January 1996, the NERC Board of Trustees formed a Board-level task force to expeditiously reexamine and reassess NERC's future role, responsibilities, and organizational structure in light of the rapidly changing electric industry environment. In the summer of 1996, outages in the West pushed the issue of reliability higher up on the industry restructuring agenda and put significant new emphasis on the reexamination of NERC's future role. Up until January 1997, NERC and the Regional Councils relied on peer pressure to ensure compliance with established standards. In 1997, NERC began a process of changing its rules to make compliance with them mandatory.

II. Project Overview and Charge to the Blue Ribbon Panel

It is in this context that the NERC Board of Trustees, at its May 1997 meeting, articulated a need for an independent, credible, facilitated process that establishes a "Blue Ribbon Reliability Panel" of outside experts to provide a set of recommendations on the future of NERC to the Board and the industry. As charged by the NERC Board, the Panel, with assistance from the Florida Conflict Resolution Consortium's project design team, will address the ideal management framework and appropriate division of reliability functions and responsibilities (policy setting, oversight, and implementation) for assuring continued reliability of North America's interconnected bulk electric systems.

The Panel is being asked to complete, in six months, a review and evaluation of NERC's management structure, administration processes, capabilities, members, and committee structure in light of the emerging competitive and disaggregated structure for the industry. The Panel in its deliberations will be considering:

- how reliability interests and commercial needs should be addressed and balanced within this industry,

- options for enforcement of reliability standards,
- the appropriate roles and responsibilities of existing reliability institutions and how these functions should be managed and funded,
- the appropriate roles and responsibilities of the private and public interests, and
- how different scenarios for the industry's future may shape reliability assurance functions and responsibilities within the industry.

The study process will include preliminary research and synthesis of information developed by the project design team followed by a facilitated, intensive three-meeting process for a total of six days of Panel deliberation. The briefing materials will be designed to serve as potential "candidate copy" for the Panel to consider as part of its final report and will address: issue identification, network analysis survey, comparable industry experiences, policy environment review, and an initial options framework for analysis and deliberation. The Consortium's project design team will closely coordinate its efforts with the NERC staff and leadership throughout the process. NERC will take responsibility for selecting a balanced, credible group of members to serve on the Panel and provide the Panel with a clear charge for its efforts. The management and staffing of the process will be the responsibility of the Florida Conflict Resolution Consortium team.

III. The Panel

The Panel is being formed now, with most of those invited officially confirmed. It represents a balance of business, government, academia, and industry. They are all top-notch individuals known for their vision and independent thinking.

Charles G. Stalon* — Oliver, Oliver & Waltz, P.C. and former FERC Commissioner
Leonard S. Hyman — Senior Industry Advisor, Smith Barney
Vernon L. Smith — Regents' Professor for Economics and Director of Research and Education, University of Arizona, Economic Science Laboratory
Richard Drouin — Vice Chairman, Morgan Stanley Canada and former CEO of Hydro Québec
Alex Radin — President, Radin & Associates, Inc. and former Executive Director of APPA
Richard E. Balzhiser — President Emeritus of the Electric Power Research Institute
Victor Gilinsky — former NRC Commissioner
George L. Edwards — President and CEO of Alliance for Telecommunications Industry Solutions
Hazel O'Leary — former Secretary of Energy
Mary L. Schapiro** — President of National Association of Securities Dealers Regulation, Inc.
William H. Clagett** — Former NERC Chairman and former Administrator of WAPA

*Organizing Chairman
**Invited

IV. The Future of NERC — A Preliminary Reliability Issues Review Framework

The NERC Blue Ribbon Reliability Panel is utilizing the framework below as a template for both gathering information and perspectives and for its analysis and deliberation. The panel is focusing on how reliability interests and commercial needs should be addressed and balanced and the ideal management framework and appropriate division of roles and responsibilities for ensuring continued reliability of North America's interconnected bulk electric systems. This framework reflects the Panel's interest in being open to all realistic options related to the future organization of an effective reliability assurance framework.

1. **Mission and Function —** What should be the mission and function(s) of the organization(s) established to ensure reliability in the future? In what important ways would this mission and these functions differ from the present?

2. **Guiding Qualities —** What are the most important qualities the organization(s) must possess to carry out the future mission and functions?

3. **Authority/Compliance —** What tools (laws, agreements, procedures, etc.) are needed to assure the capacity of the organization(s) to carry out reliability functions?

4. **Governance —** How should the organization(s) design its governance functions to appropriately share power and responsibility among its members?

5. **Government Interface —** What should be the relationship between the organization(s) and relevant government agencies?

6. **Membership —** Who should be members of the organization(s) in the future and what should be the conditions and responsibilities for membership?

7. **Regional Arrangements —** In what ways should the present Regional system and arrangements involving the Regional Reliability Councils and NERC be preserved and/or changed?

8. **Implementation —** What should be the major responsibilities of the following parties within the organization(s) in the future: the Board; Staff; Member Institution Volunteers; Contractors; and Others.

9. **Finance —** What is the best way(s) to fund the organization(s) in the future?

10. **Public Participation —** What should the organization(s) do to inform and provide participation opportunities for interested parties and the general public in the future?

V. Overall Blue Ribbon Panel Schedule and Deliverables at a Glance

A. Schedule

1. <u>Preparation for Launch</u>: June–August 1997. Research and preparation of briefing materials including interviews with Committee members and meetings with the NERC Task Force.

2. <u>First Meeting (two days)</u>: September 20–21, 1997, Toronto, Ontario, Canada. Objective: briefing, issue identification, member preferences and agreement on the work plan, organization of report text and additional information needed.

3. <u>Second Meeting (two days)</u>: October 25–26, 1997, San Francisco, California. Objective: additional expert briefing, areas of agreement and open issues articulated.

4. Final Meeting (two days): December 6–7, 1997, Austin, Texas.

5. Report Preparation: December 1997

6. Final Report Presentation: January 1998

B. Project Deliverables

1. High profile final consulting report including Blue Ribbon Panel's specific findings and recommendations and relevant supporting information on framework, future scenarios, etc.

2. Preliminary status report to the Board of Trustees in September 1997.

3. Final report draft by December 31, 1997 for presentation at the January 1998 Board of Trustees meeting.

4. Final report for distribution in January 1998.

Exhibit 4

NERC Electric Reliability Panel
September 20-21, 1997 Meeting
Toronto, Ontario, Canada

Proposed Meeting Objectives

- Draw lessons and principles from other relevant research and information;
- Develop a working “best bet” 2010 scenario for industry change (economic, social, political, technological) to guide discussion of critical questions;
- Identify critical issues and develop key questions and options for the Panel’s issues framework;
- Test for Panel preferences on options identified;
- Agree on Panel leadership and next steps and the October 25-26, 1997 meeting agenda.

Exhibit 5

North American Electric Reliability Council
COMPLIANCE TEAM

Report to the Future Role of NERC Task Force
Recommended Funding Approach

Background

The Chair of the Future Role of NERC Task Force (FRTF), Gary Neale, requested that the Compliance Team develop several alternative ways for the funding of NERC (or reliability functions). This effort was to facilitate discussion of the FRTF who will ultimately make recommendations to the Board of Trustees. Compliance Team members include Nick Brown (Southwest Power Pool), Dave Goulding (Ontario Hydro), Bill Newman (Southern Company), Paul Barber (Citizens Power), Jim Byrd (TU Electric), and Vikram Budhraja (Southern California Edison).

The initial assignment was completed through a series of telephone conference calls and a report was made to the FRTF on June 11 identifying several funding options. Based on this report and subsequent discussion, the FRTF directed the Compliance Team to develop a specific recommendation on a funding approach for NERC, independent of a decision on who NERC's future members may be.

At their July 30, 1997 meeting, following discussion of previous funding methods developed by the Compliance Team and methods in use or proposed by several Regions, the Compliance Team reached unanimous agreement on a recommend funding approach.

Recommended Funding Approach

NERC should assess its members based on actual expenses per a Board of Trustees approved annual budget. Seventy-five percent of this assessment should be prorated between all members based on their end-use energy consumption during the previous calendar year. Twenty-five percent of this assessment should be shared equally by all members.

Supporting Principles and Assumptions

The recommended funding approach is based on the following principles and assumptions:

- Services provided by the NERC organization to a subset of members should be paid for by those members as negotiated between those members and NERC Staff. These services should NOT a) deter NERC Staff responsibilities, b) be included in the portion of the NERC budget funded by this approach, and c) be the responsibility of NERC organizational groups.
- The Compliance Team believes that NERC should, and probably will, remain primarily a policy setting organization without a significant role in the

provision of operational services. As such, a service fee component in the funding approach is not appropriate and would be difficult to implement because of a required FERC filing or rulemaking or legislation spanning multiple jurisdictions.

- End-use customers are the ultimate beneficiary of reliable service and ultimately pay all related costs. As such, a significant portion of costs should be allocated to Members per their energy consumption. This process should be administered to preclude duplicate counting of end-use energy consumption.
- Some portion (anywhere between 1/5 and 1/3) should be shared equally by Members as direct recipients of NERC services and due to their administrative burden on the organization.
- The Compliance Team believes the recommended funding process provides independence of influence from any industry segment, Member, service recipient, etc.
- The Compliance Team believes the recommended funding process is flexible and can be appropriately applied to any approach taken on who NERC's Members are in the future - Regions, ISOs, RTGs, individual companies, or end-use customers.

<u>Strategic Initiatives for NERC — Available Transfer Capability</u>

As a direct outcome of the Board's Strategic Initiative on defining Available Transfer Capability (ATC), NERC developed the *Available Transfer Capability Definitions and Determination* reference document, published in June 1996. A key follow-on recommendation as a result of that report was:

> "All Regions (or subregions) should develop procedures for the determination and posting of available transfer capabilities and the allocation of transmission services (including reservations and scheduling), taking into account the ATC Principles in the Task Force's report."

The ATC Implementation Working Group (ATCWG) was formed to review the Regional ATC implementation plans and calculation procedures to ensure that they comply with the principles in the ATC reference document. That review is now complete and the ATCWG presented its compliance report to the Engineering and Operating Committees at their July 1997 meetings. The report concludes that existing or planned Regional procedures for calculating ATC are in concert with the principles in the ATC reference document.

In accepting the report and in addressing the Working Group's follow-on recommendations, the Engineering and Operating Committees agreed to the following future ATCWG activities:

1. Perform another complete review and reassessment of Regional compliance with ATC Principles and the implementation of coordinated intra- and interregional ATC values.

2. Develop guidelines for assessing the commercial viability (technical usability) of the ATC values derived from the Regional methodologies. Trial evaluations of the MAIN and MAPP ATC values will be performed to evaluate the guidelines and assessment techniques.

3. Prepare a progress report on the expected completion date for Regional implementation of ATC methodologies and their coordination of ATC values. Regions are encouraged to complete their implementation plans for intra- and interregional ATC determination and coordination for the summer of 1998 (by April 1, 1998).

4. Authorize the ATCWG to expand its scope and take the lead in the effort to coordinate the necessary data for near-term (next day to the next season) ATC calculations and to facilitate the development of processes, tools, and infrastructures, as a team effort with the Regions, to accomplish this data exchange.

5. Continue to investigate transmission reliability margin (TRM) and capacity benefit margin (CBM) calculation methods and their application in ATC determination. A symposium will be held in early 1998 on the sharing of methodologies, issues, and concerns to further the understanding of TRM and CBM applications in ATC.

Action: None

Agenda Item 11b1
BOT Meeting
September 15–16, 1997

Strategic Initiatives for NERC — Standards

NERC Planning Standards

At its January 6–7, 1997 meeting, the NERC Board of Trustees approved the Engineering Committee (EC) proceeding with the implementation of the activities outlined in its "Proposed Action Plan to Establish Revised and New NERC Planning Standards and Guides" report. That report, prepared by the EC's Standards and Measurement Task Force, identified the general areas where Planning Standards are needed and why Standards are required in each area. It also established a project schedule that called for EC-approved Planning Standards to be presented to the Board for approval at the Board's September 1997 meeting.

The "Interim NERC Planning Standards" report (Exhibit 1 — provided under separate cover) is the result of the EC's effort. This report, prepared by the EC's Reliability Criteria Subcommittee with the assistance of the EC's other subgroups, was approved at the July 8–9, 1997 EC meeting as an interim NERC reference document. It is intended that the NERC Planning Standards apply not only to the Regional Councils and their members, but to all users of the interconnected electric systems. In approving this report, the EC adopted the following resolution:

> The Engineering Committee approves the June 20, 1997 *NERC Planning Standards* report as an interim reference document. The report will be submitted to the NERC Board of Trustees at its September 1997 meeting for approval as an interim NERC Standards document. The document will be revisited and reapproved when the following are complete:
>
> 1. An implementation plan detailing schedules for compliance,
> 2. Procedures for compliance review and enforcement, and
> 3. Process for review of the Standards by request and by periodic scheduled review.
>
> As an interim document, it is intended that the Regions and all impacted parties develop implementation plans, and thoroughly review the interim Standards to support the finalization of the Standards.
>
> The Committee recognizes that a parallel effort is underway to further develop a "due process and appeals" procedure for standards development and review. It is the intent of the Committee to provide the opportunity for such "due process" review, as may be subsequently approved by the Board of Trustees, to any of its Planning Standards.

As an interim document, the Regions and all impacted parties are expected to develop implementation plans and thoroughly review the interim Standards. It is intended that this document be revisited and reapproved when an implementation plan and schedule as well as procedures for compliance review and enforcement are complete. Further, it is anticipated that any modifications to these Planning Standards will be by way of a Board-approved "process for developing and approving NERC Standards."

With this understanding, the EC-approved Planning Standards report (Exhibit 1) is being presented to the Board for approval as an "Interim NERC Planning Standards" reference document.

The EC recognizes that Planning Standards development will be an ongoing process with continual changes, but recommends acceptance of its report as the first such industry effort to establish Planning Standards for which compliance is to be mandatory.

Additional background information on this report and its development process are included in the attached Exhibit 2.

Action: Approve the EC's proposed Planning Standards report as an "Interim NERC Planning Standards" reference document.

Exhibit 1
(Agenda Item 11b1
BOT Meeting
September 15–16, 1997)

Interim
NERC PLANNING STANDARDS

North American Electric Reliability Council

Prepared by
Reliability Criteria Subcommittee
of the
NERC Engineering Committee

Approved by NERC Engineering Committe
July 8, 1997

Approved by NERC Board of Trustees
September __, 1997

Contents

Foreword

This **NERC Planning Standards** report is the result of the NERC Engineering Committee's efforts to address how NERC will carry out its reliability mission by establishing, measuring performance relative to, and ensuring compliance with **NERC Policies**, **Standards**, **Principles**, and **Guides**. From the planning or assessment perspective, this report establishes **Standards** and defines in terms of **Measurements** the required actions or system performance necessary to comply with the **Standards**. This report also provides **Guides** that describe good planning practices for consideration by all electric industry participants.

Mandatory compliance with the **NERC Planning Standards** is required of the NERC Regional Councils (Regions) and their members as well as all other electric industry participants if the reliability of the interconnected bulk electric systems is to be maintained in the competitive electricity environment. This report, however, does not address issues of implementation, compliance, and enforcement of the **Standards**. The timing and manner in which implementation and enforcement of and compliance with the **NERC Planning Standards** will be achieved has yet to be defined.

Background

At its September 1996 meeting, the NERC Board of Trustees unanimously accepted the report, *Future Course of NERC*, of its Future Role of NERC Task Force — II. This report outlines several findings and recommendations on NERC's future role and responsibilities in the light of the rapidly changing electric industry environment.

The report also concluded that NERC will carry out its reliability mission by:

- Establishing Reliability Policies, Standards, Principles, and Guides,
- Measuring Performance Relative to NERC Policies, Standards, Principles, and Guides, and
- Ensuring Conformance to and Compliance with NERC Policies, Standards, Principles, and Guides.

In accepting the Task Force's report, the Board also directed the NERC Engineering Committee and Operating Committee to develop appropriate implementation plans to address the recommendations in the *Future Course of NERC* report and to present these plans to the Board at its January 1997 meeting. The primary focus of the action plans and the initiatives from the Engineering Committee perspective was the development of **Planning Standards and Guides**. At its January 1997 meeting, the NERC Board of Trustees accepted the Engineering Committee's November 1996 "Proposed Action Plan to Establish Revised and New NERC Planning Standards and Guides" report. This action plan formed the basis for the development of **NERC's Planning Standards**.

Standards Development

The Engineering Committee assigned the overall responsibility for the development and coordination of the **NERC Planning Standards** to its Reliability Criteria Subcommittee (RCS). The Engineering Committee's other subgroups were also called upon to provide major inputs to RCS in its **Planning Standards** development effort. These other subgroups included: the Reliability Assessment Subcommittee, the Interconnections Dynamics Working Group, the Multiregional Modeling Working Group, the System Dynamics Database Working Group, the Load Forecasting Working Group, and the Available Transfer Capability Implementation Working Group.

In the development of the **NERC Planning Standards**, all proposed **Standards, Measurements, and Guides** were distributed for Regional and electric industry review prior to their submittal to the Engineering Committee and Board for approval. The Engineering Committee recognized that the **NERC Planning Standards** would have to be more specific than in the past, and that differences among the Regions would still need to be considered. It also recognizes that the development of **Planning Standards** will be an evolutionary process with continual additions, changes, and deletions.

The Engineering Committee extends its appreciation to the members of its subgroups and the members of the Regions and electric industry sectors that commented on the proposed drafts of the **NERC Planning Standards** in their development phases. A substantial effort was expended to develop the **NERC Planning Standards** in a very short time frame.

The **NERC Planning Standards** continue to define the reliability of the interconnected bulk electric systems using the following two terms:

- **Adequacy** — The ability of the electric systems to supply the aggregate electrical demand and energy requirements of their customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
- **Security** — The ability of the electric systems to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

The Engineering Committee recognizes that this **NERC Planning Standards** report is the first such industry effort to establish industry **Planning Standards** requiring mandatory compliance by the Regions, their members, and all other electric industry participants. This report also defines the specific actions or system performance that must be met to ensure compliance with the **Planning Standards**.

The new competitive electricity environment is fostering an increasing demand for transmission services. With this focus on transmission and its ability to support competitive electric power transfers, all users of the interconnected transmission systems must understand the electrical limitations of the transmission systems and their capability to support a wide variety of transfers.

Foreword

The future challenge to the reliability of the electric systems will be to plan and operate transmission systems so as to provide requested electric power transfers while maintaining overall system reliability.

Introduction

Electric system reliability begins with planning. The **NERC Planning Standards** state the fundamental requirements for planning reliable interconnected bulk electric systems. The **Measurements** define the required actions or system performance necessary to comply with the **Standards**. The **Guides** describe good planning practices and considerations.

With open access to the transmission systems in connection with the new competitive electricity market, all electric industry participants must accept the responsibility to observe and comply with the NERC **Planning Standards** and to contribute to their development and continued improvement. That is, compliance with the **NERC Planning Standards** by the Regional Councils (Regions) and their members as well as all other electric industry participants is mandatory.

The Regions and their members along with all other electric industry participants are encouraged to consider and follow the **Guides**, which are based on the **NERC Planning Standards**. The application of **Guides** is expected to vary to match load conditions and individual system requirements and characteristics.

Background

In January 1996, the NERC Board of Trustees formed a task force to reassess NERC's future role, responsibilities, and organizational structure in light of the rapidly changing electric industry environment. The task force's report, *Future Course of NERC*, accepted by the Board at its September 1996 meeting, concluded that NERC will carry out its reliability mission by:

- Establishing Reliability Policies, Standards, Principles, and Guides,
- Measuring Performance Relative to NERC Policies, Standards, Principles, and Guides, and
- Ensuring Conformance to and Compliance with NERC Policies, Standards, Principles, and Guides.

In January 1997, the Board voted unanimously to obligate its Regional and Affiliate Councils and their members to promote, support, and comply with all NERC Planning and Operating Policies.

Regional Planning Criteria and Guides

The Regions, subregions, power pools, and their members have the primary responsibility for the reliability of bulk electric supply in their respective areas. These entities also have the responsibility to develop their own appropriate or more detailed planning and operating reliability criteria and guides that are based on the **Planning Standards** and which reflect the diversity of individual electric system characteristics, geography, and demographics for their areas.

Therefore, all electric industry participants must also adhere to applicable Regional, subregional, power pool, and individual member planning criteria and guides. In those cases where Regional, subregional, power pool, and individual member planning criteria and guides are more restrictive than the **NERC Planning Standards**, the more restrictive reliability criteria and guides must be observed.

Responsibilities for Planning Standards, Measurements, and Guides

The NERC Board of Trustees approves the **NERC Planning Standards, Measurements, and Guides** to ensure that the interconnected bulk electric systems are planned reliably.

To assist the Board, the NERC Engineering Committee:

- Develops the **NERC Planning Standards, Measurements, and Guides** for the Board's approval, and
- Coordinates the **NERC Planning Standards, Measurements, and Guides**, as appropriate, with corresponding Operating Policies, Standards, Measurements, and Guides developed by the NERC Operating Committee.

The Regions, subregions, power pools, and their members:

- Develop planning criteria and guides that are applicable to their respective areas and which are in compliance with the **NERC Planning Standards,**
- Coordinate their planning criteria and guides with neighboring Regions and areas, and
- Agree on planning criteria and guides to be used by intra- and interregional groups in their planning and assessment activities.

Format of the NERC Planning Standards

The presentation of the **Planning Standards** in this report is based on the following general format:

- **Introduction** — Background and reason(s) for the **Standard(s)**.
- **Standard** — Statement of the specifics requiring compliance.
- **Measurement** — Measure(s) of performance relative to the **Standard**.
- **Guides** — Good planning practices and considerations that may vary for local conditions.
- **Compliance and Enforcement** — Not addressed in this report.

The **NERC Planning Standards** are in bold face type to distinguish them from the other sections of the report. In some cases, the **Measurements** of a Standard are multifaceted and address several characteristics of the bulk electric systems or system components.

Definition of Bulk Electric System

The **NERC Planning Standards, Measurements, and Guides** in this report are intended to apply primarily to the bulk electric systems, also referred to as the interconnected transmission systems or networks. Because of the individual character of each of the Regions, it is recommended that each Region define those facilities that are to be included as its bulk electric systems or interconnected transmission systems for which application of the **Planning Standards** will be required. Any differences from the following Board definition of bulk electric system shall be documented and reported to the NERC Engineering Committee prior to the application or implementation of the **Planning Standards** in this report.

The NERC Board of Trustees at its April 1995 meeting approved a definition for the bulk electric system as follows:

> **"The bulk electric system is a term commonly applied to that portion of an electric utility system, which encompasses the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher."**

This definition is included in the May 1995 NERC brochure on "Planning of the Bulk Electric Systems" prepared by a task force of the Engineering Committee.

A system facility, element, or component has been defined as any generating unit, transmission line, transformer, or piece of electrical equipment comprising an electric system. This definition is included in the May 1995 NERC *Transmission Transfer Capability* reference document.

Compliance With NERC Planning Standards

The interconnected bulk electric systems in the United States, Canada, and the northern portion of Baja California, Mexico are comprised of many individual systems, each with its own electrical characteristics, set of customers, and geographic, weather, and economic conditions, and regulatory and political climates. By their very nature, the bulk electric systems involve multiple parties. Since all electric systems within an integrated network are electrically connected, whatever one system does can affect the reliability of the other systems. Therefore, to maintain the reliability of the bulk electric systems or interconnected transmission systems or networks, the Regions and their members and all electric industry participants must comply with the **NERC Planning Standards**.

The interconnected transmission systems are the principal media for achieving reliable electric supply. They tie together the major electric system facilities, generation resources, and customer demand centers. These systems must be planned, designed, and constructed to operate reliably within thermal, voltage, and stability limits while achieving their major purposes. These purposes are to:

- **Deliver Electric Power to Areas of Customer Demand** — Transmission systems provide for the integration of electric generation resources and electric system facilities to ensure the reliable delivery of electric power to continuously changing customer demands under a wide variety of system operating conditions.

- **Provide Flexibility for Changing System Conditions** — Transmission capacity must be available on the interconnected transmission systems to provide flexibility to handle the shift in facility loadings caused by the maintenance of generation and transmission equipment, the forced outages of such equipment, and a wide range of other system variable conditions, such as construction delays, higher than expected customer demands, and generating unit fuel shortages.

- **Reduce Installed Generating Capacity** — Transmission interconnections with neighboring electric systems allow for the sharing of generating capacity through diversity in customer demands and generator availability, thereby reducing investment in generation facilities.

- **Allow Economic Exchange of Electric Power Among Systems** — Transmission interconnections between systems, coupled with internal system transmission facilities, allow for the economic exchange of electric power among all systems and industry participants. Such economy transfers help to reduce the cost of electric supply to customers.

Electric power transfers have a significant effect on the reliability of the interconnected transmission systems, and must be evaluated in the context of the other functions performed by these interconnected systems. In some areas, portions of the transmission systems are being loaded to their reliability limits as the uses of the transmission systems change relative to those for which they were planned, and as opposition to new transmission prevents facilities from being constructed as planned. Efforts by all industry participants to minimize costs will also continue to encourage, within safety and reliability limits, maximum loadings on the existing transmission systems.

The new competitive electricity environment is fostering an increasing demand for transmission services. With this focus on transmission and its ability to support competitive electric power transfers, all users of the interconnected transmission systems must understand the electrical limitations of the transmission systems and the capability of these systems to reliably support a wide variety of transfers. The future challenge will be to plan and operate transmission systems that provide the requested electric power transfers while maintaining overall system reliability.

All electric utilities, transmission providers, electricity suppliers, purchasers, marketers, brokers, and society at large benefit from having reliable interconnected bulk electric systems. To ensure that these benefits continue, all industry participants must recognize the importance of planning these systems in a manner that promotes reliability.

The **NERC Planning Standards, Measurements, and Guides** pertaining to System Adequacy and Security (I.) are provided in the following sections:

A. Transmission Systems
B. Reliability Assessment
C. Facility Connection Requirements
D. Voltage Support and Reactive Power
E. Transfer Capability
F. Disturbance Monitoring

Introduction

The fundamental purpose of the interconnected transmission systems is to move electric power from areas of generation to areas of customer demand (load). These systems should be capable of performing this function under a wide variety of expected system conditions (e.g., forced and maintenance equipment outages, continuously varying customer demands) while continuing to operate reliably within equipment and electric system thermal, voltage, and stability limits.

Electric systems must be planned to withstand the more probable forced and maintenance outage system contingencies at projected customer demand and anticipated electricity transfer levels.

Extreme but less probable contingencies measure the robustness of the electric systems and should be evaluated for risks and consequences. The risks and consequences of these contingencies should be reviewed by the entities responsible for the reliability of the interconnected transmission systems. Actions to mitigate or eliminate the risks and consequences are at the discretion of those entities.

The ability of the interconnected transmission systems to withstand probable and extreme contingencies must be determined by simulated testing of the systems as prescribed in these I.A. Standards on Transmission Systems.

Standards

S1. The interconnected transmission systems shall be planned, designed, and constructed such that with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the network can deliver generator unit output to meet projected customer demands and provide contracted firm (non-recallable reserved) transmission services, at all demand levels, under the conditions defined in Category A of Table I (attached).

S2. The interconnected transmission systems shall be planned, designed, and constructed such that the network can be operated to supply projected customer demands and contracted firm (non-recallable reserved) transmission services, at all demand levels, under the conditions of the contingencies as defined in Category B of Table I (attached).

The transmission systems also shall be capable of accommodating planned bulk electric equipment maintenance outages and continuing to operate within thermal, voltage, and stability limits under the conditions of the contingencies as defined in Category B of Table I (attached).

S3. The interconnected transmission systems shall be planned, designed, and constructed such that the network can be operated to supply projected customer demands and contracted firm (non-recallable reserved) transmission services, at all demand levels, under the conditions of the contingencies as defined in Category C of Table I (attached). The controlled interruption of customer demand, the planned removal of generators, or the curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard.

The transmission systems also shall be capable of accommodating planned bulk electric equipment maintenance outages and continuing to operate within thermal, voltage, and stability limits under the conditions of the contingencies as defined in Category C of Table I (attached).

S4. The interconnected transmission systems shall be evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I (attached).

Measurements

M1. Entities responsible for the reliability of the interconnected transmission systems shall ensure that the system responses for Standard S1 are as defined in Category A of Table I (attached) and summarized below:

a. All system facilities in service.
b. Line and equipment loadings shall be within normal thermal rating limits.
c. Voltage levels shall be maintained within normal limits.
d. Stability of the network shall be maintained.
e. All customer demands shall be supplied, and all contracted firm (non-recallable reserved) transfers shall be maintained.
f. Cascading outages shall not occur.

M2. Entities responsible for the reliability of the interconnected transmission systems shall ensure that the system responses for Standard S2 contingencies are as defined in Category B of Table I (attached) and summarized below:

a. Initiating incident results in a single component out of service.
b. Line and equipment loadings shall be within applicable rating limits.
c. Voltage levels shall be maintained within applicable limits.
d. Stability of the network shall be maintained.
e. No unplanned loss of customer demand or generation (except as noted in Table I) shall occur, and no contracted firm (non-recallable reserved) transfers shall be curtailed.

f. Cascading outages shall not occur.

M3. Entities responsible for the reliability of the interconnected transmission systems shall ensure that the system responses for Standard S3 are as defined in Category C of Table I (attached) and summarized below:

a. Initiating incident may result in two or more (multiple) components out of service.
b. Line and equipment loadings shall be within applicable thermal rating limits.
c. Voltage levels shall be maintained within applicable limits.
d. Stability of the network shall be maintained.
e. Planned outages of customer demand or generation (as noted in Table I) may occur, and contracted firm (non-recallable reserved) transfers may be curtailed.
f. Cascading outages shall not occur.

M4. Entities responsible for the reliability of the interconnected transmission systems shall assess the risks and system responses for Standard S4 as defined in Category D of Table I (attached).

Where such extreme contingency events could lead to uncontrolled cascading outages or system instability, the entities shall document the measures and procedures to mitigate or eliminate the extent and effects of those events and may at their discretion implement such measures and procedures.

M5. Entities responsible for the reliability of the interconnected transmission systems shall document their assessment activities in compliance with the I.B. Standard on Reliability Assessment to ensure that their respective systems are in compliance with these I.A. Standards on Transmission Systems. This documentation shall be provided to NERC on request. (S1, S2, S3, and S4)

Guides

G1. The planning, development, and maintenance of transmission facilities should be coordinated with neighboring systems to preserve the reliability benefits of interconnected operations.

G2. Studies affecting more than one system owner or user should be conducted on a joint interconnected system basis.

G3. The interconnected transmission systems should be designed and operated such that reasonable and foreseeable contingencies do not result in the loss or unintentional separation of a major portion of the network.

G4. The interconnected transmission systems should provide flexibility in switching arrangements, voltage control, and other protection system measures to ensure reliable system operation.

G5. The assessment of transmission system capability and the need for system enhancements should take into account the maintenance outage plans of the transmission facility owners. These maintenance plans should be coordinated on an intra- and interregional basis.

G6. The interconnected transmission systems should be planned to avoid excessive dependence on any one transmission circuit, structure, right-of-way, or substation.

G7. Reliability assessments should examine post-contingency steady-state conditions as well as stability, overload, cascading, and voltage collapse conditions. Pre-contingency system conditions chosen for analysis should include contracted firm (non-recallable reserved) transmission services.

G8. Annual updates to the transmission assessments should be performed, as appropriate, to reflect anticipated significant changes in system conditions.

G9. Extreme contingency evaluations should be conducted to measure the robustness of the interconnected transmission systems and to maintain a state of preparedness to deal effectively with such events. Although it is not practical (and in some cases not possible) to construct a system to withstand all possible extreme contingencies without cascading, it is desirable to control or limit the scope of such cascading or system instability events and the significant economic and social impacts that can result.

G10. It may be appropriate to conduct the extreme contingency assessments on a coordinated intra- or interregional basis so that all potentially affected entities are aware of the possibility of cascading or system instability events.

Table I. Transmission Systems Standards — Normal and Contingency Conditions

Category	Contingencies		System Limits or Impacts				
	Initiating Event(s) and Contingency Component(s)	Components Out of Service	Thermal Limits	Voltage Limits	System Stable	Loss of Demand or Curtailed Firm Transfers	Cascading Outages [c]
A – No Contingencies	All Facilities in Service	None	Normal	Normal	Yes	No	No
B – Event resulting in the loss of a single component.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:		Applicable	Applicable			
	1. Generator	Single	Rating [a] (A/R)	Rating [a] (A/R)	Yes	No [b]	No
	2. Transmission Circuit	Single	A/R	A/R	Yes	No [b]	No
	3. Transformer	Single	A/R	A/R	Yes	No [b]	No
	Loss of a Component without a Fault.	Single	A/R	A/R	Yes	No [b]	No
	Single Pole Block, Normal Clearing:						
	4. Single Pole (dc) Line	Single	A/R	A/R	Yes	No [b]	No
C – Event(s) resulting in the loss of two or more (multiple) components.	SLG Fault, with Normal Clearing:						
	1. Bus Section	Multiple	A/R	A/R	Yes	Planned [d]	No
	2. Breaker (failure or internal fault)	Multiple	A/R	A/R	Yes	Planned [d]	No
	SLG or 3Ø Fault, with Normal Clearing, Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing:						
	3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Multiple	A/R	A/R	Yes	Planned [d]	No
	Bipolar Block, with Normal Clearing:						
	4. Bipolar (dc) Line	Multiple	A/R	A/R	Yes	Planned [d]	No
	Fault (non 3Ø), with Normal Clearing:	Multiple	A/R	A/R	Yes	Planned [d]	No
	5. Double Circuit Towerline						
	SLG Fault, with Delayed Clearing:						
	6. Generator; 8. Transformer	Multiple	A/R	A/R	Yes	Planned [d]	No
	7. Transmission Circuit; 9. Bus Section	Multiple	A/R	A/R	Yes	Planned [d]	No

D [e] – Extreme event resulting in two or more (multiple) components removed or cascading out of service	3Ø Fault, with Delayed Clearing (stuck breaker or protection system failure): 1. Generator 3. Transformer 2. Transmission Circuit 4. Bus Section 3Ø Fault, with Normal Clearing: 5. Breaker (failure or internal fault) Other: 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of a all generating units at a station 11. Loss of a large load or major load center 12. Failure of a fully redundant special protection system (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant special protection system (or remedial action scheme) for an event or condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from disturbances in another Regional Council.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems. ▪ Document measures or procedures to mitigate the extent and effects of such events. ▪ Mitigation or elimination of the risks and consequences of these events shall be at the discretion of the entities responsible for the reliability of the interconnected transmission systems.

Footnotes to Table I.

a) Applicable rating (A/R) refers to the applicable normal and emergency facility thermal rating or system voltage limit as determined and consistently applied by the system or facility owner.
b) Planned or controlled interruption of generators or electric supply to radial customers or some local network customers, connected to or supplied by the faulted component or by the affected area, may occur in certain areas without impacting the overall security of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted firm (non-recallable reserved) electric power transfers.
c) Cascading is the uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread service interruption which cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies.
d) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.
e) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

Introduction

To ensure the reliability of the interconnected bulk electric systems, the NERC Engineering Committee, through its Reliability Criteria Subcommittee (RCS), reviews and assesses Regional planning criteria and guides to evaluate if they are in concert with the **NERC Planning Standards**.

The NERC Engineering Committee, through its Reliability Assessment Subcommittee (RAS), also reviews and assesses the overall reliability (adequacy and security) of the bulk electric systems, both existing and as planned, to ensure that each Region (subregion) conforms to its own Regional planning criteria and guides and to the **NERC Planning Standards**.

To carry out these missions, RCS and RAS must have sufficient data and input from the Regions to evaluate Regional criteria and guides and to prepare and publish NERC's seasonal and annual assessments of the reliability of the interconnected bulk electric systems.

RAS's adequacy and security assessments must ensure the requirements stated in each Region's planning criteria and guides and the **NERC Planning Standards** are met.

Regions must also assess their Regional bulk electric system reliability within the context of the interconnected networks. Therefore, the members of a Region must coordinate their assessment efforts not only within their Region, but also with neighboring systems and Regions.

Standards

S1. Regional planning criteria and guides shall be reviewed and evaluated to ensure that they are in compliance with the NERC Planning Standards.

S2. The overall reliability (adequacy and security) of the Regions' interconnected bulk electric systems shall be reviewed and assessed, both existing and as planned, to ensure that each Region conforms to its own Regional planning criteria and guides and to the NERC Planning Standards.

Measurements

M1. Each Region's planning criteria and guides shall be reviewed at least every three years by the NERC Engineering Committee (through its RCS) to ensure that they are in compliance with the **NERC Planning Standards**. The results of these reviews shall be documented and reported to the NERC Engineering Committee and Board of Trustees. (S1)

M2. The interconnected bulk electric systems of the NERC Regions shall be assessed annually by the NERC Engineering Committee (through its RAS) for adequacy and security over a ten-year horizon. While the availability of ten-year planning data may become more difficult under a competitive environment, the long lead time for some essential facilities (e.g., transmission) requires a long-term reliability assessment. (S2)

a. Regional and interregional seasonal (summer and winter) reliability assessments shall be conducted annually by the NERC Engineering Committee (RAS) prior to both the summer and winter seasons. The results of these reliability assessments shall be published annually prior to each season. (S2)

b. Ten-year Regional and interregional reliability assessments for representative years, dictated by system events, shall be conducted annually by the NERC Engineering Committee (RAS) to evaluate the anticipated performance and reliability of the planned interconnected systems. The results of the ten-year reliability assessments shall be published annually. (S2)

M3. Each Region shall annually provide to the NERC Engineering Committee (RAS) a summary of its Regional reliability assessments for the seasonal and ten-year planning horizons. Similarly, Regions shall annually provide a coordinated or joint summary of their interregional reliability assessments. Interregional studies shall be conducted to ensure that the Regional bulk electric systems are planned and developed on a coordinated or joint basis to preserve the adequacy and security of the interconnected bulk electric systems. The NERC Engineering Committee (RAS) shall review Regional and interregional reliability assessments to ensure that they are in compliance with the **NERC Planning Standards** and shall publish the results of these reviews. (S2)

M4. Each Region shall annually provide data to NERC as outlined in the NERC RAS Procedures Manual and in compliance with the **NERC Planning Standards** on System Modeling Data Requirements (II) as defined in this report. The NERC RAS shall develop, maintain, and distribute its Procedures Manual to each Region. (S2)

M5. The annual reports developed by the NERC Engineering Committee (RAS) of the results of the reliability assessments shall include: the overall adequacy of generation and transmission resources, the security of the interconnected systems, the relative adequacy of the Regions compared to their respective Regional planning criteria and guides and the **NERC Planning Standards**, key Regional reliability issues, and the risks and uncertainties affecting Regional adequacy and security. (S1, S2)

Introduction

All facilities involved in the generation, transmission, and use of electricity must be properly connected to the interconnected transmission systems to avoid degrading the reliability of the electric systems to which they are connected. To avoid adverse impacts on reliability, generation and transmission owners and electricity end-users must meet facility connection and performance requirements as specified by those responsible for the reliability of the interconnected transmission systems.

Standards

S1. Facility connection requirements shall be documented, maintained, and published by voltage class, capacity, and other characteristics that are applicable to generation, transmission, and electricity end-user facilities and which are connected to, or being planned to be connected to, the interconnected transmission systems.

S2. Generation, transmission, and electricity end-user facilities, and their modifications, shall be planned and integrated into the interconnected transmission systems in compliance with NERC Planning Standards, applicable Regional, subregional, power pool, and individual system planning criteria, guides, and facility connection requirements.

Measurements

M1. Those entities responsible for the reliability of the interconnected transmission systems shall document, maintain, and publish facility connection requirements for generation facilities, transmission facilities, and electricity end-user facilities to ensure compliance with NERC **Planning Standards** and applicable Regional, subregional, power pool, and individual system planning criteria, guides, and facility connection requirements. The documentation shall include the assumptions and considerations used to establish the requirements, and shall be provided to the Regions and NERC on request. (S1)

M2. Those entities responsible for the reliability of the interconnected transmission systems and those entities seeking to integrate generation facilities, transmission facilities, and electricity end-user facilities shall coordinate and cooperate on their respective assessments to evaluate the reliability impact of the new facilities and their connections on the interconnected transmission systems and to ensure compliance with **NERC Planning Standards** and applicable Regional, subregional, power pool, and individual system planning criteria, guides, and facility connection requirements. The results of these assessments shall be documented and provided to the Regions and NERC on request. (S2)

Guides

G1. Inspection requirements for connected facilities or new facilities to be connected should be included in the facility connection requirements documentation.

G2. Examples of reliability issues that should be addressed in the published facility connection requirements include:

a. Supervisory control and data acquisition
b. Telemetering and metering
c. Communications during normal and emergency conditions
d. Voltage and power factor control
e. Equipment ratings
f. Reactive power requirements
g. Short circuit conditions
h. System protection and other controls
I. Generation control
j. Maintenance coordination
k. Synchronizing facilities
l. System grounding
m. Responsibilities during emergency conditions
n. Abnormal frequency and voltage operation

G3. Notification of new facilities to be connected, or modifications of existing facilities already connected to the interconnected transmission systems should be provided to those responsible for the reliability of the interconnected transmission systems as soon as feasible to ensure that a review of the reliability impact of the facilities and their connections can be performed and that the facilities are placed in service in a timely manner.

Introduction

Sufficient reactive resources must be located throughout the electric systems, with a balance between static and dynamic characteristics. Both static and dynamic reactive power resources are needed to supply the reactive power requirements of customer demands and the reactive power losses in the transmission and distribution systems, and provide adequate system voltage support and control. They are also necessary to avoid voltage instability and widespread system collapse in the event of certain contingencies. Transmission systems cannot perform their intended functions without an adequate reactive power supply.

Dynamic reactive power support and voltage control are essential during power system disturbances. Synchronous generators, synchronous condensers, and static var compensators (SVCs and STATCOMs) can provide dynamic support. Transmission line charging and series and shunt capacitors are also sources of reactive support, but are static sources.

Reactive power sources must be distributed throughout the electric systems among the generation, transmission, and distribution facilities, as well as at some customer locations. Because customer reactive demands and facility loadings are constantly changing, coordination of distribution and transmission reactive power is required. Unlike active or real power (MWs), reactive power (Mvars) cannot be transmitted over long distances and must be supplied locally.

Standard

S1. Reactive power resources, with a balance between static and dynamic characteristics, shall be planned and distributed throughout the interconnected transmission systems to ensure system performance as defined in Categories A, B, and C of Table I in the I.A. Standards on Transmission Systems.

Measurements

M1. Entities responsible for the reliability of the interconnected transmission systems shall conduct assessments (at least every five years or as required by changes in system conditions) to ensure reactive power resources are available to meet projected customer demands, firm (non-recallable) electric power transfers, and the system performance requirements as defined in Categories A, B, and C of Table I of the I.A. Standards on Transmission Systems. Documentation of these assessments shall be provided to the Regions and NERC on request. (S1)

M2. Generation owners and transmission providers shall work jointly to optimize the use of generator reactive power capability. These joint efforts shall include:

a. Coordination of generator step-up transformer impedance and tap specifications and settings,
b. Calculation of underexcited limits based on machine thermal and stability considerations, and
c. Ensuring that the full range of generator reactive power capability is available for applicable normal and emergency network voltage ranges. (S1)

Guides

G1. Transmission owners should plan and design their reactive power facilities so as to ensure adequate reactive power reserves in the form of dynamic reserves at synchronous generators, synchronous condensers, and static var compensators (SVCs and STATCOMs) in anticipation of system disturbances. For example, fixed and mechanically-switched shunt compensation should be used to the extent practical so as to ensure reactive power dynamic reserves at generators and SVCs to minimize the impact of system disturbances.

G2. Distribution entities and customers connected directly to the transmission systems should plan and design their systems to operate at close to unity power factor to minimize the reactive power burden on the transmission systems.

G3. At continuous rated power output, new synchronous generators should have an overexcited power factor capability, measured at the generator terminals, of 0.9 or less and an underexcited power factor capability of 0.95 or less.

If a synchronous generator does not meet this requirement, the generation owner should make alternate arrangements for supplying an equivalent dynamic reactive power capability to meet the area's reactive power requirements.

G4. Reactive power compensation should be close to the area of high reactive power consumption or production.

G5. A balance between fixed compensation, mechanically-switched compensation, and continuously-controlled equipment should be planned.

G6. Voltage support and voltage collapse studies should conform to Regional guidelines.

G7. Power flow simulation of contingencies, including P-V and V-Q curve analyses, should be used and verified by dynamic simulation when steady-state analyses indicate possible insufficient voltage stability margins.

G8. Consideration should be given to generator shaft clutches or hydro water depression capability to allow generators to operate as synchronous condensers.

Introduction

A competitive electricity market is dependent on the availability of adequate transmission services. The availability of these services must be based strictly on the physical and electrical characteristics and capabilities of the interconnected transmission networks as reliably planned and operated under the **NERC Planning Standards**, the NERC Operating Policies, and applicable Regional, subregional, power pool, and individual system criteria and guides.

For a commercially viable electricity market, the total transfer capability (TTC) and the available transfer capability (ATC) for particular directions must be available to the market participants. These transfer capabilities are generally calculated through computer simulations of the interconnected transmission systems under a specific set of system conditions. These simulations are performed “off line” for both near-term (operating horizon) and longer-term (planning horizon) periods.

The definitions of the key TTC and ATC transfer capability terms that bridge the technical characteristics of interconnected transmission system performance and the commercial requirements associated with transmission service requests are as follows:

- The total transfer capability (TTC) is 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.

- Available transfer capability (ATC) is a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as TTC less existing transmission commitments (including retail customer service and capacity benefit margin (CBM)), less a transmission reliability margin (TRM). (CBM is the amount of transfer capability reserved by load-serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements. TRM is that amount of transfer capability necessary to ensure that the transmission systems are secure under a range of uncertainties in system conditions.)

TTC and ATC values must satisfy certain principles that balance both technical and commercial issues. These principles are defined in NERC’s June 1996 *Available Transfer Capability Definitions and Determination* reference document.

Standards

S1. The calculation of TTC and ATC values for the planning horizon shall comply with the system performance requirements of Categories A, B, and C of Table I of the I.A. Standards on Transmission Systems and appropriate Regional criteria and guides.

S2. The calculation of TTC and ATC values for the operating horizon shall comply with the system performance requirements of Categories A and B of Table I of the I.A. Standards on Transmission Systems and appropriate Regional criteria and guides.

Measurements

M1. Each Region shall develop and document its methodologies and guidelines for calculating and updating TTC and ATC values for the planning and operating horizons. This documentation shall be provided to appropriate Regions and NERC on request. (S1, S2)

M2. Each transmission provider (or its agent) shall establish the need and the methodologies for determining TRM and CBM. This information shall be provided to appropriate Regions and NERC on request. (S1, S2)

M3. Each transmission provider (or its agent) shall take into account known conditions in other systems that affect TTC and ATC values and coordinate those impacts on TTC and ATC with adjacent systems, subregions, and Regions. (S1, S2)

M4. Each Region shall review and coordinate the TTC and ATC methods and values used by the transmission providers to ensure agreement in data reporting within and among Regions. (S1, S2)

Guides

G1. All TTC and ATC analyses should consider the best available information on anticipated system configuration and conditions (facility outages, reactive support, generation patterns, etc.) for the time period under study.

G2. Base system conditions should be identified and modeled for the period being analyzed, including customer demands, generation dispatch, system configuration, and firm (non-recallable reserved) transmission services.

G3. In determining transfer capabilities, generation and transmission system contingencies throughout the interconnected transmission systems should be evaluated to determine which facility outages are most restrictive to the transfer being analyzed.

G4. TRM and CBM values should be developed and applied as separate and independent components of transfer capability margin.

G5. The specific methodologies for determining TRM and CBM may vary among Regions, subregions, power pools, individual systems, and load-serving entities. However, these methodologies should be well documented and consistently applied.

Introduction

Recorded information about transmission system faults or disturbances is essential to determine the performance of system components and to analyze the nature and cause of a disturbance. Such information can help to identify equipment misoperations, and the causes of oscillations that may have contributed to a disturbance. Protection system and control deficiencies can also be analyzed and corrected, reducing the risk of recurring misoperations. Transient modeling data can be gathered from fault and sequence-of-event monitoring equipment and long-time modeling data can be gathered from dynamic monitoring equipment using wide-area measurement techniques or swing sensors.

Standards

S1. Requirements for the installation of disturbance monitoring equipment (e.g., sequence-of-event, fault recording, and dynamic disturbance recording equipment) that is necessary to ensure data is available to determine system performance and the causes of system disturbances shall be established on a Regional basis.

S2. Requirements for providing disturbance monitoring data for the purpose of developing, maintaining, and updating transmission system models shall be established on a Regional basis.

Measurements

M1. Each Region shall develop a plan that defines the requirements for the installation of disturbance monitoring equipment to ensure data is available to determine system performance and the causes of system disturbances. Documentation of Regional disturbance monitoring equipment plans shall be provided to appropriate Regions and NERC on request. (S1)

M2. Regional members shall provide to their respective Regions a list of their disturbance monitoring equipment that is installed and operational in compliance with Regional requirements. (S1)

M3. Each generation owner and transmission provider shall maintain a database of all disturbance monitoring equipment installations, and shall provide such information to the Region and NERC on request. (S1)

M4. Each Region shall establish requirements for providing disturbance monitoring data to ensure that data is available to determine system performance and the causes of system disturbances. Documentation of Regional data reporting requirements shall be provided to appropriate Regions and NERC on request. (S2)

M5. Regional members shall provide to their respective Regions system fault and disturbance data in compliance with Regional requirements. Each Region shall maintain and annually update a database of the recorded information. (S1, S2)

M6. Regional members shall use recorded data from disturbance monitoring equipment to develop, maintain, and enhance steady-state and dynamic system models and generator performance models. (S2)

Guides

G1. Data from transmission system disturbance monitoring equipment should be in a consistent, time synchronized format.

G2. The Regional database should be used to identify locations on the transmission systems where additional disturbance monitoring equipment may be needed.

G3. The monitored data should be used to validate generator models and steady-state and dynamic system simulations.

G4. Each Region should establish and coordinate the requirements for the installation of disturbance monitoring equipment with neighboring Regions.

System modeling is the first step toward reliable interconnected transmission systems. The timely development of system modeling data to realistically simulate the electrical behavior of the components in the interconnected networks is the only means to accurately plan for reliability. To achieve this purpose, the **NERC Planning Standards** on System Modeling Data Requirements (II) establishes a set of common objectives for the development and submission of necessary data for electric system reliability assessment.

The detail in which the various system components are modeled should be adequate for all intra- and interregional reliability assessment activities. This means that system modeling data should include sufficient detail to ensure that system contingency, steady-state, and dynamic analyses can be simulated. Furthermore, any qualified user should be able to recognize significant limiting conditions in any portion of the interconnected transmission systems.

The **NERC Planning Standards, Measurements, and Guides** pertaining to System Modeling Data Requirements (II) are provided in the following sections:

A. System Data
B. Generation Equipment
C. Facility Ratings
D. Actual and Forecast Demands
E. Demand Characteristics (Dynamic)

These **Standards, Measurements, and Guides** shall apply to all system modeling necessary to achieve interconnected transmission system performance as described in the Standards on System Adequacy and Security (I) in this report.

Introduction

Complete, accurate, and timely data is needed for system analyses to ensure the adequacy and security of the interconnected transmission systems, meet projected customer demands, and determine the need for system enhancements or reinforcements.

System analyses include steady-state and dynamic (all time frames) simulations of the electrical networks. Data requirements for such simulated modeling includes information on system components, system configuration, customer demands, and electric power transactions.

Standard

S1. Electric system data required for the analysis of the reliability of the interconnected transmission systems shall be developed and maintained.

Measurements

M1. Those entities responsible for the reliability of the interconnected transmission systems, in conjunction with the Regions, shall identify the scope and specificity of the steady-state and dynamics data required for reliability analyses and the procedures for data reporting. These requirements and procedures shall be periodically (at least every five years) reviewed, documented, and published for all users[a] of the interconnected transmission systems. (S1)

M2. All the users of the interconnected transmission systems shall provide appropriate equipment characteristics and system data in compliance with the respective "procedural manuals" for the modeling and simulation of the steady-state behavior of portions or all of the four NERC Interconnections: Eastern, Western, ERCOT, and Hydro-Québec.[b] This data shall be provided to the Regions, NERC, and those entities responsible for the reliability of the interconnected transmission systems on request. (S1)

M3. The NERC Multiregional Modeling Working Group or its successor group(s) shall maintain and distribute the steady-state data requirements "procedural manual" pertaining to the Eastern Interconnection. Similar "procedural manuals" shall be

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[a]Users of the electric systems include all entities owning, using, or reserving service on the interconnected transmission systems, or connecting or planning to connect facilities to operate in synchronism with the electric systems.

[b]Hydro-Québec uses the Procedural Manual of the Eastern Interconnection.

maintained and distributed by the Western (WSCC), ERCOT, and Hydro-Québec[a] Interconnections. (S1)

The following list briefly describes typical steady-state data that shall be reported:

a. Bus (substation and switching station): names, nominal voltage, and location.

b. Generating Units (including synchronous condensers, pumped storage, etc.): location, minimum and maximum ratings (net real and reactive power), regulated bus and voltage set point, maintenance requirements as appropriate to the analysis, station service and auxiliary loads, and dynamics data. (See II.B. Generation Equipment.)

c. AC Transmission Line or Circuit (overhead and underground): nominal voltage, impedance, line charging, nominal and emergency ratings based on the most limiting element in the circuit, maintenance requirements as appropriate to the analysis, and metering locations.

d. Transformer (voltage and phase-shifting): nominal voltages of windings, impedance, tap ratios (voltage and/or phase angle or tap step size), regulated bus and voltage set point, normal and emergency ratings, and maintenance requirements as appropriate to the analysis.

e. Reactive Compensation (shunt and series capacitors and reactors): nominal ratings, impedance, percent compensation, connection point, and controller device.

f. Short Circuit Analysis: positive, negative, zero sequence, and mutual impedances.

M4. All users of the interconnected transmission systems shall provide appropriate equipment characteristics and system data in compliance with the respective “procedural manuals” for the modeling and simulation of the dynamics behavior of portions or all of the four NERC Interconnections: Eastern, Western, ERCOT, and Hydro-Québec.[a] (S1)

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[a]Hydro-Québec uses the Procedural Manual of the Eastern Interconnection.

M5. The NERC System Dynamics Database Working Group or its successor group(s) shall maintain and distribute the dynamics data requirements "procedural manual" pertaining to the Eastern Interconnection. Similar "procedural manuals" shall be maintained and distributed by the Western (WSCC), ERCOT, and Hydro-Québec[a] Interconnections. (S1)

The following list briefly describes representative dynamics data that shall be reported:

a. Unit-specific dynamics data shall be reported for generators, excitation systems, voltage regulators, turbine-governor systems, power system stabilizers, and other associated generation equipment. In no case shall other than unit-specific data be reported for generator units installed after 1990.

b. Typical manufacturer's dynamics data, based on units of similar design and characteristics, may be submitted when unit-specific dynamics data cannot be obtained.

c. Dynamics data shall be consistent with the reported steady-state (power flow) data.

M6. Data requirements for the steady-state and dynamics modeling of other associated transmission and generation facilities are included under the following sections of the **Standards**:

- Voltage Support and Reactive Power (I.D.)
- Disturbance Monitoring (I.F.)
- Generation Equipment (II.B.)
- Facility Ratings (II.C.)
- System Protection and Control (III)
- System Restoration (IV)

M7. Load-serving entities shall provide actual and forecast demands for their respective customers for steady-state and dynamics system modeling as specified in the respective steady-state and dynamics procedural manuals for the Interconnections and in compliance with the Actual and Forecast Demands (II.D.) and Demand Characteristics (Dynamic) (II.E.) Standards in this report. (S1)

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[a]Hydro-Québec uses the Procedural Manual of the Eastern Interconnection.

M8. All purchasers, sellers, marketers, and load-serving entities shall provide their existing and future contracted firm (non-recallable reserved) capacity transactions (including sources, sinks, amounts, duration, associated transmission, etc.) for steady-state and dynamics system modeling as specified in the respective steady-state and dynamics procedural manuals for the Interconnections and in compliance with the Transfer Capability Standard (I.E.) in this report. (S1)

Guides

G1. Any changes to interconnection tie line data should be agreed upon by all involved facility owners.

G2. The in-service date should be the first year and season that a facility will be operable or placed in service.

G3. The out-of-service date should be the first year and season that the facility will be retired or taken out of service.

G4. All data should be screened to detect inappropriate or inaccurate data.

G5. The reactive limits of generators should be periodically reviewed and field tested, as appropriate, to ensure that reported var limits are attainable. (See Generation Equipment Standard II.B.)

G6. Generating station service load (SSL) and auxiliary load representations should be provided to those entities responsible for the reliability of the interconnected transmission systems on request. The presence of SSL in a dynamic simulation will alter the bus angles derived from solution. This change in angle can be significant from the steady-state, dynamic, and voltage control perspectives, especially for large generating units.

G7. To accurately model system inertia, the netting of generation and customer demand should be avoided.

G8. Generating units equal to or greater than 50 MVA should generally be individually modeled. To maintain sufficient detail in the model, larger units should not be lumped together.

G9. Smaller generating units at a particular station may be lumped together and represented as one unit. The lumping of generating units at a station is acceptable where all units have the same electrical and control characteristics. Equivalent lumped units should generally not exceed 300 MVA.

G10. The dynamics data for each generating unit should be supplied on the machine's own MVA and kV base.

G11. Data for generator step-up transformers should include effective tap ratios and per unit impedance (R and X values) on the transformer's MVA and kV base.

Introduction

Validation of generator modeling data through field verification and testing is critical to the reliability of the interconnected transmission systems. Accurate, validated generator models and data are essential for planning and operating studies used to ensure electric system reliability.

Generating capability to meet projected system demands and provide the required amount of generation capacity margins is necessary to ensure service reliability. This generating capability must be accounted for in a uniform manner that ensures the use of realistically attainable values when planning and operating the systems or scheduling equipment maintenance.

Synchronous generators are the primary means of voltage and frequency control in the bulk interconnected electric systems. The correct operation of generator controls can be the crucial factor in whether the electric systems can sustain a severe disturbance without a cascading breakup of the interconnected network. Generator dynamics data is used to evaluate the stability of the electric systems, analyze actual system disturbances, identify potential stability problems, and analytically validate solutions for the identified problems.

Generator reactive capability is commonly derived from the generator real and reactive capability curves supplied by the manufacturer. Reactive power generation limits derived in this manner can be optimistic as heating or auxiliary bus voltage limits may be encountered before the generator reaches its maximum sustained reactive power capability. Manufacturer-provided design data may also not accurately reflect the characteristics of operational field equipment because settings can drift and components deteriorate over time. Field personnel may also change equipment settings (to resolve specific local problems) that may not be communicated to those responsible for developing a system modeling database and conducting system assessments. It is important to know the actual reactive power limits, control settings, and response times of generation equipment and to represent this information accurately in the system modeling data that is supplied to the Regions and those entities responsible for the reliability of the interconnected transmission systems.

Standard

S1. Generation equipment shall be tested to verify that data submitted for steady-state and dynamics modeling in planning and operating studies is consistent with the actual physical characteristics of the equipment. The data to be verified and provided shall include generator gross and net dependable capability, gross and net reactive power capability, voltage regulator controls, speed/load governor controls, and excitation systems.

Measurements

M1. Each Region shall establish and maintain procedures for generation equipment data verification and testing for all types of generating units in its Region. These procedures shall address generator gross and net dependable capability, reactive power capability, voltage regulator controls, speed/load governor controls, and excitation systems (including power system stabilizers and other devices, if applicable). These procedures shall also address generating unit exemption criteria and shall require documentation of those generating units that are exempt from a portion or all of these procedures. (S1)

M2. Generation equipment owners shall annually test to verify the gross and net dependable capability of their units. They shall provide the Regions with the following information on request:

a. Summer and winter gross and net capabilities of each unit based on the power factor level expected for each unit at the time of summer and winter peak demand, respectively.

b. Active or real power requirements of auxiliary loads.

c. Date and conditions during tests (ambient and design temperatures, generator loadings, voltages, hydrogen pressure, high-side voltage, and auxiliary loads). (S1)

M3. Generation equipment owners shall test to verify the gross and net reactive power capability of their units at least every five years. They shall provide the Regions with the following information on request:

a. Maximum sustained reactive power capability (both lagging and leading) as a function of real power output and generator terminal voltage. If safety or system conditions do not allow testing to full capability, computations and engineering reports of estimated capability shall be provided.

b. Reason for reactive power limitation.

c. Reactive power requirements of auxiliary loads.

d. Date and conditions during tests (ambient and design temperatures, generator loadings, voltages, hydrogen pressure, high-side voltage, and auxiliary loads). (S1)

M4. Generation equipment owners shall test voltage regulator controls and limit functions at least every five years. Upon request, they shall provide the Regions with the status of voltage regulator testing as well as information that describes how generator controls coordinate with the generator's short-term capabilities and protective relays. Test reports shall include minimum and maximum excitation limiters (volts/hertz), gain and time constants, the type of voltage regulator control function, date tested, and the voltage regulator control setting. (S1)

M5. Generation equipment owners shall test speed/load governor controls at least every five years. Upon request, they shall provide the Regions with the status of governor tests as well as information that describes the characteristics (droop and deadband) of the speed/load governing system. (S1)

M6. Generation equipment owners shall verify the dynamic model data for excitation systems (including power system stabilizers and other devices, if applicable) at least every five years. Design data for new or refurbished excitation systems shall be provided at least one year prior to the in-service date with updated data provided once the unit is in service. Open circuit test response chart recordings shall be provided showing generator field voltage and generator terminal voltage. (Brushless units shall include exciter field voltage and current.) (S1)

Guides

G1. The following guidelines should be observed during testing of the reactive power capability of a generator:

a. The reactive power capability curve for each generating unit should be used to determine the expected reactive power capability.

b. Units should be tested while maintaining the scheduled voltage on the system bus. Coordination with other units may be necessary to maintain the scheduled voltage.

c. Hydrogen pressure in the generating unit should be at rated operating pressure.

d. Overexcited tests should be conducted for a minimum of two hours or until temperatures have stabilized.

e. When the maximum sustained reactive power output during the test is achieved, the following quantities should be recorded: generator gross MW and Mvar output, auxiliary load MW and Mvar, and generator and system voltage magnitudes.

G2. Most modern voltage regulators have limiting functions that act to bring the generating unit back within its capabilities when the unit experiences excessive field voltage, volts per hertz, or underexcited reactive current. These limiters are often intended to coordinate with other controls and protective relays. Testing should be done that demonstrates correct action of the controls and confirms the desired set points.

G3. Generation equipment owners should make a best effort to verify data necessary for system dynamics studies. An "open circuit step in voltage" is an easy to perform test that can be used to validate the generating unit and excitation system dynamics data. The open circuit test should be performed with the unit at rated speed and voltage but with its breakers open. Generator terminal voltage, field voltage, and field current (exciter field voltage and current for brushless excitation systems) should be recorded with sufficient resolution such that the change in voltages and current are clearly distinguishable.

G4. More detailed test procedures should be performed when there are significant differences between "open circuit step in voltage" tests and the step response predicted with the model data. Generator reactance and time constant data can be derived from standstill frequency response tests.

G5. The response of the speed/load governor controls should be evaluated for correct operation whenever there is a system frequency deviation that is greater than that established by the Regional procedures.

Introduction

Knowledge of facility ratings is essential for the reliable planning and operation of the interconnected transmission systems. Such ratings determine acceptable electrical loadings on equipment, before, during, and after system contingencies, and together with consideration of network voltage and system stability, determine the capability of the systems to deliver electric power from generation to customer demands.

Standard

S1. Electrical facilities used in the production, transmission, storage, and delivery of electricity shall be rated in compliance with applicable Regional, subregional, power pool, and individual system planning criteria and guides.

Measurements

M1. Facility owners shall document the methodology for determining facility ratings, including delineation and justification of assumptions, standards, and practices used in establishing the ratings. This documentation shall be provided to the Regions and NERC on request. (S1)

M2. Facility owners shall provide facility ratings (applicable normal and emergency) for all facilities required for system modeling as defined under these **NERC Planning Standards** to the Regions and NERC on request. (S1)

M3. The rating of a system facility (e.g., transmission line, transformer, etc.) shall not exceed the rating of the most limiting series element in the circuit or path of the facility, including terminal connections and associated equipment. (S1)

M4. In cases where protection systems and control settings constitute a loading limit on a facility, this limit shall become the rating for that facility. (S1)

M5. Ratings of jointly-owned facilities shall be coordinated and provided on a consistent basis. (S1)

Guides

G1. System modeling should use facility ratings based on weather assumptions appropriate for the seasonal (demand) conditions being evaluated.

G2. Facility ratings should be based on or adhere to applicable national electrical codes and electric industry rating practices consistent with good engineering practice.

Introduction

Actual customer demand data is needed for forecasting future electrical requirements, reliability assessments of past electric system events, load diversity studies, and validation of databases.

Forecast customer demand data is needed for system modeling and the analysis of the adequacy and security of the interconnected transmission systems, and for identifying the need and timing of system reinforcements to reliably supply customer electrical requirements.

Actual and forecast demand data generally includes hourly, monthly, and annual demands and monthly and annual net energy for load. This data may be required on an aggregated Regional, subregional, power pool, individual system basis, or on a dispersed transmission substation basis for system modeling and reliability analysis.

In addition to customer demands and net energy for load, that portion of demand that is included in or part of controllable demand-side management programs and which may be interrupted by system operators also may be required in evaluating the adequacy and security of the interconnected transmission systems.

Standards

S1. Actual and forecast customer demands and net energy for load data required for the analysis of the reliability of the interconnected transmission systems shall be developed and maintained on an aggregated Regional, subregional, power pool, and individual system basis and on a dispersed substation basis.

S2. Controllable demand-side management (interruptible demands and direct control load management) programs and data shall be identified and documented.

Measurements

M1. The entities responsible for the reliability of the interconnected transmission systems, in conjunction with the Regions, shall identify the scope and specificity of the aggregated and dispersed actual and forecast customer demand and net energy for load data, and the controllable demand-side management data to be reported for system modeling and reliability analysis. Documentation of these customer demand and demand-side management data reporting procedures shall be provided to NERC and the Regions on request. (S1, S2)

M2. The reporting procedures that are developed shall ensure that customer demands are not double counted or omitted in reporting actual or forecast demand data on either an aggregated or dispersed basis within an area or Region. (S1)

M3. Actual and forecast customer demand data and controllable demand-side management data reported to government agencies shall be consistent with data reported to those entities responsible for the reliability of the interconnected transmission systems, the Regions, and NERC. (S1, S2)

M4. The following information shall be provided annually on an aggregated Regional, subregional, power pool, or individual system basis to NERC, the Regions, and those entities responsible for the reliability of the interconnected transmission systems:

a. Integrated hourly customer demands in megawatts (MW) for the nominal 8,760 hours for the prior year.

b. Monthly and annual peak hour actual demands in MW and net energy for load in gigawatthours (GWh) for the prior year.

c. Monthly peak hour forecast demands in MW and net energy for load in GWh for the next two years.

d. Annual peak hour forecast demands (summer and winter) in MW and annual net energy for load in GWh up to ten years into the future.

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M5. The following information shall be provided on a dispersed substation basis to NERC, the Regions, and those entities responsible for the reliability of the interconnected transmission systems:

a. Seasonal peak hour actual demands in MW and Mvars for the prior year (as defined in M1 and M2).

b. Seasonal peak hour forecast demands in MW and Mvars (as defined in M1 and M2).

M6. The actual and forecast customer demand data reported on either an aggregated or dispersed basis shall indicate whether the demand data of nonmember entities within an area or Region are included. (S1)

M7. Assumptions, methods, and the manner in which uncertainties are addressed in the forecasts of aggregated peak demands and net energy for load shall be provided to the Regions and NERC on request. (S1)

M8. The actual and forecast demand data used in system modeling and reliability analyses (by the entities responsible for the reliability of the interconnected transmission systems, the Regions, and NERC) shall be consistent with the actual and forecast demand data provided under this II.D. Standard on Actual and Forecast Demands. (S1)

M9. Customer demands that are included in or part of controllable demand-side management programs, such as interruptible demands and direct control load management, shall be separately provided on an aggregated Regional, subregional, power pool, and individual system basis to NERC, the Regions, and those entities responsible for the reliability of the interconnected transmission systems on request. (S2)

M10. Interruptible demands and direct control load management data shall each be provided annually up to ten years into the future for summer and winter peak system conditions to NERC, the Regions, and those entities responsible for the reliability of the interconnected transmission systems on request. (S2)

M11. The amount of interruptible demands and direct control load management shall be made known to system operators and security center coordinators on request. (S2)

M12. Forecasts shall clearly document how the demand and energy effects of demand-side management programs (such as conservation, time-of-use rates, interruptible demands, and direct control load management) are addressed. (S2)

Guides

G1. Actual and forecast demand data and forecast controllable demand-side management data should be provided on either an aggregated or dispersed basis in an appropriate common format to ensure consistency in reporting and to facilitate use of the data by the entities responsible for the reliability of the interconnected transmission systems, the Regions, and NERC.

G2. Weather normalized data, when provided in addition to actual data, should be identified as such and reconciled as appropriate.

G3. The characteristics of demand-side management programs used in assessing future resource adequacy should generally include:

- consistent program ratings (demand and energy), including seasonal variations
- effect on annual load shape
- availability, effectiveness, and diversity

- contractual arrangements
- expected program duration
- effects (demand and energy) of multiple programs

Introduction

The various components of customer demand respond differently to changes in system voltage and frequency. Seasonal and time-of-day variations may also affect the components and response characteristics of customer demands. Accurate representation of these customer demand characteristics is needed in system modeling since they can have important effects on system reliability.

Standard

S1. Representative frequency and voltage characteristics of customer demands (real and reactive power) required for the analysis of the reliability of the interconnected transmission systems shall be developed and maintained.

Measurements

M1. The entities responsible for the reliability of the interconnected transmission systems, in conjunction with the Regions, shall develop a plan for determining and promoting the accuracy of the representation of customer demands, identify the scope and specificity of the frequency and voltage characteristics of customer demands, and determine the procedures and schedule for data reporting.

Documentation of these customer demand characteristics (dynamic) plans and reporting procedures shall be provided to NERC and the Regions on request. (S1)

M2. The NERC System Dynamics Database Working Group or its successor group(s) shall maintain and publish customer demand characteristics requirements in its "procedural manual" pertaining to the Eastern Interconnection. Similar "procedural manuals" shall be maintained and published by the Western (WSCC), ERCOT, and Hydro-Québec[a] Interconnections. These procedural manuals shall include plans for determining and promoting the accuracy of the representation of customer demands. (S1)

M3. Load-serving entities shall provide customer demand characteristics to the Regions and those entities responsible for the reliability of the interconnected transmission systems in compliance with the respective procedural manuals for the modeling of portions or all of the four NERC Interconnections: Eastern, Western, ERCOT, and Hydro-Québec.[a] (S1)

[a]Hydro-Québec uses the Procedural Manual of the Eastern Interconnection.

Guides

G1. The representation of customer demands should generally include a combination of constant MVA, constant current, and constant impedance for real and reactive power components and frequency dependence, as appropriate.

G2. Special demand models for significant frequency and voltage dependent customer demands, such as fluorescent lighting or motors, should be provided on request.

G3. Demand characteristics for zones or areas within electric systems or at substation buses should reflect the composition of the demand at those locations.

G4. The voltage and frequency characteristics of customer demands that are used in system models should be representative of seasonal and time-of-day variations, as appropriate.

G5. The representation of customer demand characteristics should be periodically reviewed and field tested, as appropriate, to ensure the accuracy of the demand modeling.

G6. The sensitivity of simulation results to the demand models should be evaluated. High sensitivity demands (e.g., motors and certain substation demands) should generally be represented by more detailed models.

Protection and control systems are essential to the reliable operation of the interconnected transmission networks. They are designed to automatically disconnect components from the transmission network to isolate electrical faults or protect equipment from damage due to voltage, current, or frequency excursions outside of the design capability of the facilities. Control systems are those systems that are designed to automatically adjust or maintain system parameters (voltages, facility loadings, etc.) within pre-defined limits or cause facilities to be disconnected from or connected to the network to maintain the integrity of the overall bulk electric systems.

The objectives for protection and control systems generally include:

- DEPENDABILITY — a measure of certainty to operate when required,
- SECURITY — a measure of certainty not to operate falsely,
- SELECTIVITY — the ability to detect an electrical fault and to affect the least amount of equipment when removing or isolating an electrical fault or protecting equipment from damage, and
- ROBUSTNESS — the ability of a control system to work correctly over the full range of expected steady-state and dynamic system conditions.

A reliable protection and control system requires an appropriate level of protection and control system redundancy. Increased redundancy improves dependability but it can also decrease security through greater complexity and greater exposure to component failure.

Protection and control system reliability is also dependent upon sound testing and maintenance practices. These practices include defining what, when, and how to test equipment calibration and operability, performing preventive maintenance, and expediting the repair of faulty equipment.

Diagnostic tools, such as fault and disturbance recorders, can provide a record of protection and control system performance under various transmission system conditions. These records are often the only means to diagnose protection and control anomalies. Such information is also critical in determining the causes of system disturbances, the sequence of disturbance events, and developing necessary corrective and preventive actions. In some instances, these records provide information about incipient conditions that would lead to future transmission system problems.

Coordination of protection and control systems is vital to the reliability of the transmission networks. The reliability of the transmission network can be jeopardized by unintentional and unexpected automatic control actions or loss of facilities caused by misoperation or uncoordinated protection and control systems. If protection and control systems are not properly coordinated, a system disturbance or contingency event could result in the unexpected loss of multiple facilities. Such unexpected consequences can result in unknowingly operating the electric systems under unreliable conditions including the risk of a blackout, if the event should occur.

The design of protection and control systems must be coordinated with the overall design and operation of the generation and transmission systems. Proper coordination requires an understanding of:

- The characteristics, operation, and behavior of the generation and transmission systems and their protection and control,
- Normal and contingency system conditions, and
- Facility limitations that may be imposed by the protection and control systems.

Coordination requirements are specifically addressed in the areas of communications, data monitoring, reporting, and analysis throughout the **Standards, Measurements, and Guides** under System Protection and Control (III).

The **NERC Planning Standards, Measurements, and Guides** pertaining to System Protection and Control (III) are provided in the following sections:

A. Transmission Protection Systems
B. Transmission Control Devices
C. Generation Control and Protection
D. Underfrequency Load Shedding
E. Undervoltage Load Shedding
F. Special Protection Systems

These **Standards, Measurements, and Guides** shall apply to all protection and control systems necessary to achieve interconnected transmission network performance as described in the Standards on System Adequacy and Security (I) in this report.

Introduction

The goal of transmission protection systems is to ensure that faults within the intended zone of protection are cleared as quickly as possible. When isolating an electrical fault or protecting equipment from damage, these protection systems should be designed to remove the least amount of equipment from the transmission network. They should also not erroneously trip for faults outside the intended zones of protection or when no fault has occurred.

The need for redundancy in protection systems should be based on an evaluation of the system consequences of the failure or misoperation of the protection system and the need to maintain overall system reliability.

Standards

S1. Transmission protection systems shall be provided to ensure the system performance requirements as defined in the I.A. Standards on Transmission Systems and associated Table I.

S2. Transmission protection systems shall provide redundancy such that no single protection system component failure would prevent the interconnected transmission systems from meeting the system performance requirements of the I.A. Standards on Transmission Systems and associated Table I.

S3. All protection system trip misoperations shall be analyzed for cause and corrective action.

S4. Protection system maintenance and testing programs shall be developed and implemented.

Measurements

M1. Transmission or protection system owners shall review their transmission protection systems for compliance with the system performance requirements of the I.A. Standards on Transmission Systems and associated Table I. Any non-compliance shall be documented, including a plan for achieving compliance. Documentation of protection system reviews shall be provided to NERC, the Regions, and those entities responsible for the reliability of the interconnected transmission systems on request. (S1)

M2. Where redundancy in the protection systems due to single protection system component failures is necessary to meet the system performance requirements of the I.A. Standards on Transmission Systems and associated Table I, the transmission or protection system owners shall provide, as a minimum, separate ac current inputs and separately fused dc control voltage with new or upgraded protection system installations. Breaker failure protections need not be duplicated. (S2)

Each Region shall also develop a plan for reviewing the need for redundancy in its existing transmission protection systems and for implementing any required redundancy. Documentation of the protection system redundancy reviews shall be provided to NERC, the Regions, and those entities responsible for the reliability of the interconnected transmission systems on request. (S2)

M3. Each Region shall have a process in place for the monitoring, notification, and analysis of all transmission protection trip operations. Documentation of protection trip misoperations shall be provided to the affected Regions and NERC on request. (S3)

M4. Transmission or protection system owners shall have a protection system maintenance and testing program in place. Documentation of the implementation of protection system maintenance and testing shall be provided to the appropriate Regions and NERC on request. (S4)

Guides

G1. Protection systems should be designed to isolate only the faulted electric system element(s), except in those circumstances where additional elements must be removed from service intentionally to preserve electric system integrity.

G2. Breaker failure protection systems, either local or remote, should be provided and designed to remove the minimum number of elements necessary to clear a fault.

G3. The relative effects on the interconnected transmission systems of a failure of the protection systems to operate when required versus an unintended operation should be weighed carefully in selecting design parameters.

G4. Protection systems and their associated maintenance procedures should be designed to minimize the likelihood of personnel error, such as incorrect operation and inadvertent disabling.

G5. Physical and electrical separation should be maintained between redundant protection systems, where practical, to reduce the possibility of both systems being disabled by a single event or condition.

G6. Communications channels required for protection system operation should be either continuously monitored, or automatically or manually tested.

G7. Models used for determining protection settings should take into account significant mutual and zero sequence impedances.

G8. The design of protection systems, both in terms of circuitry and physical arrangement, should facilitate periodic testing and maintenance.

G9. Protection and control systems should be functionally tested, when initially placed in service and when modifications are made, to verify the dependability and security aspects of the design.

G10. Protection system applications should be reviewed whenever significant changes in generating sources, transmission facilities, or operating conditions are anticipated.

G11. The protection system testing program should include provisions for relay calibration, functional trip testing, communications system testing, and breaker trip testing.

G12. Generation and transmission protection systems should avoid tripping for stable power swings on the interconnected transmission systems.

G13. When two independent protection systems are required, dual circuit breaker trip coils should be considered.

G14. Where each of two protection systems are protecting the same facility, the equipment and communications channel for each system should be separated physically and designed to minimize the risk of both protection systems being disabled simultaneously by a single event or condition.

G15. Automatic reclosing or single-pole switching of transmission lines should be used where studies indicate enhanced system stability margins are necessary. However, the possible effects on the systems of reclosure into a permanent fault need to be considered.

G16. Protection system applications and settings should not normally limit transmission use.

G17. Application of zone 3 relays with settings overly sensitive to overload or depressed voltage conditions should be avoided where possible.

Introduction

Certain transmission devices are planned and designed to provide dynamic control of electric system quantities, and are usually employed as solutions to specific system performance issues. They typically involve feedback control mechanisms using power electronics to achieve the desired electric system dynamic response. Examples of such equipment and devices include: HVDC links, active or real power flow control and reactive power compensation devices using power electronics (e.g., unified power flow controllers (UPFCs), static var compensators (SVCs), thyristor-controlled series capacitors (TCSCs), and in some cases mechanically-switched shunt capacitors and reactors.

In planning and designing transmission control devices, it is important to consider their operation within the context of the overall interconnected systems over a variety of operating conditions. These control devices can be used to avoid degradation of system performance and cascading outages of facilities. If not properly designed, the feedback controls of these devices can become unstable during weakened system conditions caused by disturbances, and can lead to modal interactions with other controls in the interconnected systems.

Standard

S1. Transmission control devices shall be planned and designed to meet the system performance requirements as defined in the I.A. Standards of the Transmission Systems and associated Table I. These devices shall be coordinated with other control devices within a Region and, where appropriate, with neighboring Regions.

Measurements

M1. When planning new or substantially modified transmission control devices, transmission owners shall evaluate the impact of such devices on the reliability of the interconnected transmission systems. The assessment shall include sufficient modeling of the details of the dynamic devices and encompass a variety of contingency system conditions. The assessment results shall be provided to the Regions and NERC on request. (S1)

M2. Transmission owners shall provide transmission control device models and data, suitable for use in system modeling, to the Regions and NERC on request. Preliminary data on these devices shall be provided prior to their in-service dates. Validated models and associated data shall be provided following installation and energization. (S1)

M3. The transmission owners or operators shall document and periodically (at least every five years or as required by changes in system conditions) review the settings and operating strategies of the control devices. Documentation shall be provided to the Regions and NERC on request. (S1)

Guides

G1. Coordinated control strategies for the operation of transmission control devices may require switching surge studies, harmonic analyses, or other special studies.

G2. For HDVC links in parallel with ac lines, supplementary control should be considered so that the HDVC links provide synchronizing and damping power for interconnected generators. Use of HDVC links to stabilize system ac voltages should be considered.

Introduction

Generator excitation and prime mover controls are key elements in ensuring electric system stability and reliability. These controls must be coordinated with generation protection to minimize generator tripping during disturbance-caused abnormal voltage, current, and frequency conditions. Generators are the primary method of electric system dynamic voltage control, and therefore good performance of excitation equipment (exciter, voltage regulator, and, if applicable, power system stabilizer) is essential for electric system stability. Prime mover controls (governors) are the primary method of system frequency regulation.

Generator control and protection must be planned and designed to provide a balance between the need for the generator to support the interconnected electric systems during abnormal conditions and the need to adequately protect the generating equipment from damage. Unnecessary generator tripping during a disturbance aggravates the loading conditions on the remaining on-line generators and can lead to a cascading failure of the interconnected electric systems.

Accurate data that describes generator characteristics and capabilities is essential for the studies needed to ensure the reliability of the interconnected electric systems. Protection characteristics

S1. All synchronous generators connected to the interconnected transmission systems shall be operated with their excitation system in the automatic voltage control mode unless

S2. Generators shall maintain a network voltage or reactive power output as required by the transmission system operator within the reactive capability of the units. Generator step-up and auxiliary transformers shall have their tap settings coordinated with electric system voltage requirements.

S3. Temporary excursions in voltage, frequency, and real and reactive power output that a generator shall be able to sustain shall be defined and coordinated on a Regional basis.

S4. Voltage regulator controls and limit functions (such as over and under excitation and volts/hertz limiters) shall coordinate with the generator's short duration capabilities

S5. Prime mover control (governors) shall operate with appropriate speed/load

All generation protection system trip misoperations shall be analyzed for cause and

S7. Generation protection system maintenance and testing programs shall be developed and implemented.

Measurements

M1. Generation equipment owners shall provide, upon request, the Region and transmission system operator a log that specifies the date, duration, and reason for each period when the generator was not operated in the automatic voltage control mode. The procedures for reporting the data shall address generating unit exemption criteria and shall require documentation of those generating units that are exempt from a portion or all of these reporting requirements. (S1)

M2. When requested by the transmission system operator, the generating equipment owner shall provide a log that specifies the date, duration, and reason for a generator not maintaining the established network voltage schedule or reactive power output. (S2)

M3. The generation equipment owner shall provide the transmission system operator with the tap settings and available ranges for generator step-up and auxiliary transformers. When tap changes are necessary to coordinate with electric system voltage requirements, the transmission system operator shall provide the generation equipment owner with a report that specifies the required tap changes and technical justification for these changes. The procedures for reporting the data shall address generating unit exemption criteria and shall require documentation of those generating units that are exempt from a portion or all of these reporting requirements. (S2)

M4. When requested, generating equipment owners shall provide the Region and transmission system operator with the operating characteristics of any generator's equipment protective relays or controls that may respond to temporary excursions in voltage, frequency, or loading with actions that could lead to tripping of the generator. The more common protective relays include volts per hertz, loss of excitation, underfrequency, overspeed, and backup distance. (S3)

M5. Upon request, generating equipment owners shall provide the Region and transmission system operator with information that describes how generator controls coordinate with the generator's short term capabilities and protective relays. (S4)

M6. Overexcitation limiters, when used, shall be coordinated with the thermal capability of the generator field winding. After allowing temporary field current overload, the limiter shall operate through the automatic ac voltage regulator to reduce field current to the continuous rating. Return to normal ac voltage regulation after current reduction shall be automatic. The overexcitation limiter shall be coordinated with overexcitation protection so that overexcitation protection only operates for failure of the voltage regulator/limiter. (S4)

M7. Upon request, generating equipment owners shall provide the Region or transmission system operator with information that describes the characteristics of the speed/load governing system. Boiler or nuclear reactor control shall be coordinated to maintain the capability of the generator to aid control of system frequency during an electric system disturbance to the extent possible while meeting the safety requirements of the plant. Nonfunctioning or blocked speed/load governor controls shall be reported to the Region and transmission system operator. (S5)

M8. Each Region shall have a process in place for the monitoring, notification, and analysis of all generation protection trip operations. Documentation of protection trip misoperations shall be provided to the affected Regions and NERC on request. (S6)

M9. Generation equipment owners shall have a generation protection system maintenance and testing program in place. Documentation of the implementation of protection system maintenance and testing shall be provided to the appropriate Regions and NERC on request. (S7)

Guides

G1. Power system stabilizers improve damping of generator rotor speed oscillations. They should be applied to a unit where studies have determined the possibility of unit or system instability and where the condition can be improved or corrected by the application of a power system stabilizer. Power system stabilizers should be designed and tuned to have a positive damping effect on local generator oscillations and on inter-area oscillations without deteriorating turbine/generator shaft torsional oscillation damping.

G2. Generators and turbines should be designed and operated so that there is additional reactive power capability that can be automatically supplied to the system during a disturbance.

G3. Generator control and protection should be periodically tested to the extent practical to ensure the generator plant can provide the designed control, and operate without tripping for specified voltage, frequency, and load excursions. Control responses should be checked periodically to validate the model data used in simulation studies.

G4. New or upgraded excitation equipment should consider high initial response, as inherent in brushless or static exciters.

G5. Generator step-up transformer and auxiliary transformers should have tap settings that are coordinated with electric system voltage control requirements and which do not limit maximum use of the reactive capability (lead and lag) of the generators.

G6. Prime mover control (governors) should operate freely to regulate frequency. In the absence of Regional requirements for the speed/load control characteristics, governor droop should generally be set at 5% and total governor deadband (intentional plus unintentional) should generally not exceed +/– 0.06%. These characteristics should in most cases ensure a coordinated and balanced response to grid frequency disturbances. Prime movers operated with valves or gates wide open should control for overspeed/overfrequency.

G7. Prime mover overspeed controls to the extent practical should be designed and adjusted to prevent boiler upsets and trips during partial load rejection characterized by abnormally high system frequency.

G8. Generator voltage regulators to the extent practical should be tuned for fast response to step changes in terminal voltage or voltage reference. It is preferable to run the step change in voltage tests with the generator not connected to the system so as to eliminate the system effects on the generator voltage. Terminal voltage overshoot should generally not exceed 10% for an open circuit step change in voltage test.

G9. New or upgraded excitation equipment to the extent practical should have an exciter ceiling voltage that is generally not less than 1.5 times the rated output field voltage.

G10. Power plant auxiliary motors should not trip or stall for momentary undervoltage associated with the contingencies as defined in Categories A, B, and C of the I.A. Standards on Transmission Systems, unless the loss of the associated generating unit(s) would not cause a violation of the contingency performance requirements.

Introduction

A coordinated automatic underfrequency load shedding (UFLS) program is required to help preserve the security of the generation and interconnected transmission systems during major declining system frequency events. Such a program is essential to minimize the risk of total system collapse, protect generating equipment and transmission facilities against damage, provide for equitable load shedding (interruption of electric supply to customers), and help ensure the overall reliability of the interconnected systems.

Load shedding resulting from a system underfrequency event should be controlled so as to balance generation and customer demand (load), permit rapid restoration of electric service to customer demand that has been interrupted, and when necessary re-establish transmission interconnection ties.

Standards

S1. A Regional UFLS program shall be planned and implemented in coordination with other UFLS programs, if any, within the Region and, where appropriate, with neighboring Regions.

S2. The Regional UFLS program shall be coordinated with generation control and protection systems, undervoltage load shedding programs, Regional load restoration programs, and transmission protection and control systems.

Measurements

M1. Each Region shall develop, coordinate, and document a Regional UFLS program, including descriptions of the following:

a. Coordination of UFLS programs within the subregions, Region, and, where appropriate, among Regions.

b. Coordination of the amount of load shedding necessary to arrest frequency decay, minimize loss of load, and permit timely system restoration.

c. Coordination of UFLS programs with generation protection and control, undervoltage load shedding programs, Regional load restoration programs, and transmission protection and control.

d. Design details including size of coordinated load shedding blocks (% of connected load), corresponding frequency set points, relay and breaker operating times, intentional delays, related generation protection, tie tripping schemes, islanding schemes, automatic load restoration schemes, or any other schemes that are part of or impact the UFLS programs.

Documentation of each Region's UFLS program shall be provided to NERC on request. (S1, S2)

M2. Those entities owning or operating an UFLS program shall ensure that their programs are consistent with Regional UFLS program requirements including automatically shedding load in the amounts and at the locations, frequencies, rates, and times consistent with those Regional requirements. (S1)

M3. Each Region shall maintain and annually update an UFLS program database. This database shall include sufficient information to model the UFLS program in dynamic simulations of the interconnected transmission systems. (S1)

M4. Each Region shall periodically (at least every five years or as required by changes in system conditions) conduct and document a technical assessment of the effectiveness of the design and implementation of its UFLS program. Documentation of the UFLS technical assessment shall be provided to NERC on request. (S1)

M5. Those entities owning or operating UFLS equipment shall have a maintenance program to test and calibrate their UFLS relays to ensure accuracy and reliable operation. Documentation of the implementation of the maintenance program shall be provided to the Regions and NERC on request. (S1)

M6. Those entities owning or operating UFLS programs shall analyze and document all system underfrequency events below the initializing set points of their UFLS programs. Documentation of the analysis shall be provided to the Regions and NERC on request. (S1)

Guides

G1. The UFLS programs should occur in steps related to frequency or rate of frequency decay as determined from system simulation studies.

G2. The technical assessment of UFLS programs should include reviews of system design and dynamic simulations of disturbances that would cause the largest expected imbalances between customer demand and generation. Both peak and off-peak system demand levels should be considered. The assessments should predict voltage and power transients at a widespread number of locations as well as the rate of frequency decline, and should reflect the operation of underfrequency sensing devices. Potential system separation points and resulting system islands should be determined.

G3. Except for qualified automatic isolation plans, the opening of transmission interconnections by underfrequency relaying should be considered only after the coordinated load shedding program has failed to arrest system frequency decline and intolerable system conditions exist.

G4. A generation-deficient entity may establish an automatic islanding plan in lieu of automatic load shedding, if by doing so it removes the burden it has imposed on the transmission systems. This islanding plan may be used only if it complies with the Regional UFLS program and leaves the remaining interconnected bulk electric systems intact, in demand and generation balance, and with no unacceptable high voltages.

G5. In cases where area isolation with a large surplus of generation compared to demand can be anticipated, automatic generator tripping or other remedial measures should be considered to prevent excessive high frequency and resultant uncontrolled generator tripping and equipment damage.

G6. UFLS relay settings and the underfrequency protection of generating units as well as any other manual or automatic actions that can be expected to occur under conditions of frequency decline should be coordinated.

G7. The UFLS program should be separate, to the extent possible, from manual load shedding schemes such that the same loads are not shed by both schemes.

G8. Generator underfrequency protection should not operate until the UFLS programs have operated and failed to maintain the system frequency at an operable level. This sequence of operation is necessary both to limit the amount of load shedding required and to help the systems avoid a complete collapse. Where this sequence is not possible, UFLS programs should consider and compensate for any generator whose underfrequency protection is required to operate before a portion of the UFLS program.

G9. Plans to shed load automatically should be examined to determine if unacceptable overfrequency, overvoltage, or transmission overloads might result. Potential unacceptable conditions should be mitigated.

If overfrequency is likely, the amount of load shed should be reduced or automatic overfrequency load restoration should be provided.

If overvoltages are likely, the load shedding program should be modified (e.g., change the geographic distribution) or mitigation measures (e.g., coordinated tripping of shunt capacitors or reactors) should be implemented to minimize that probability.

If transmission capabilities will likely be exceeded, the underfrequency relay settings (e.g., location, trip frequency, or time delay) should be altered or other actions taken to maintain transmission loadings within capabilities.

G10. Where the UFLS program fails to arrest frequency decline, generators may be isolated with local load to minimize loss of generation and enable timely system restoration. However, care should be taken to avoid unacceptable conditions, such as delayed fault clearing, overvoltages, ferroresonance, or extended undervoltages.

Introduction

Electric systems that experience heavy loadings on transmission facilities with limited reactive power control can be vulnerable to voltage instability. Such instability can cause tripping of generators and transmission facilities resulting in loss of customer demand as well as system collapse. Since voltage collapse can occur suddenly, there may not be sufficient time for operator actions to stabilize the systems. Therefore, a load shedding scheme that is automatically activated as a result of undervoltage conditions in portions of a system can be an effective means to stabilize the interconnected systems and mitigate the effects of a voltage collapse.

It is imperative that undervoltage relays be coordinated with other system protection and control devices used to interrupt electric supply to customers.

Standards

S1. Automatic undervoltage load shedding (UVLS) programs shall be planned and implemented in coordination with other UVLS programs in the Region and, where appropriate, with neighboring Regions.

S2. All UVLS programs shall be coordinated with generation control and protection systems, underfrequency load shedding programs, Regional load restoration programs, and transmission protection and control programs.

Measurements

M1. Those entities owning or operating UVLS programs shall coordinate and document their UVLS programs including descriptions of the following:

a. Coordination of UVLS programs within the subregions, the Region, and, where appropriate, among Regions.

b. Coordination of UVLS programs with generation protection and control, UFLS programs, Regional load restoration programs, and transmission protection and control programs.

c. Design details including size of customer demand (load) blocks (% of connected load), corresponding voltage set points, relay and breaker operating times, intentional delays, related generation protection, islanding schemes, automatic load restoration schemes, or any other schemes that are part of or impact the UVLS programs.

Documentation of the UVLS programs shall be provided to the appropriate Regions and NERC on request. (S1, S2)

M2. Those entities owning or operating UVLS programs shall ensure that their programs are consistent with any Regional UVLS programs and that exist including automatically shedding load in the amounts and at locations, voltages, rates, and times consistent with any Regional requirements. (S1)

M3. Each Region shall maintain and annually update an UVLS program database. This database shall include sufficient information to model the UVLS program in dynamic simulations of the interconnected transmission systems. (S1)

M4. Those entities owning or operating UVLS programs shall periodically (at least every five years or as required by changes in system conditions) conduct and document a technical assessment of the effectiveness of the design and implementation of its UVLS program. Documentation of the UVLS technical assessment shall be provided to the appropriate Regions and NERC on request. (S1)

M5. Those entities owning or operating UVLS programs shall have a maintenance program to test and calibrate their UVLS relays to ensure accuracy and reliable operation. Documentation of the implementation of the maintenance program shall be provided to the appropriate Regions and NERC on request. (S1)

M6. Those entities owning or operating an UVLS program shall analyze and document all system undervoltage events below the initiating set points of their UVLS programs. Documentation of the analysis shall be provided to the appropriate Regions and NERC on request. (S1)

Guides

G1. UVLS programs should be coordinated with other system protection and control programs (e.g., timing of line reclosing, tap changing, overexcitation limiting, capacitor bank switching, and other automatic switching schemes).

G2. Automatic UVLS programs should be coordinated with manual load shedding programs.

G3. Manual load shedding programs should not include, to the extent possible, customer demand that is part of an automatic UVLS program.

G4. Assessments of UVLS programs should include system dynamic simulations that represent generator overexcitation limiters, load restoration dynamics (tap changing, motor dynamics), and shunt compensation switching.

G5. Plans to shed load automatically should be examined to determine if acceptable overfrequency, overvoltage, or transmission overloads might result. Potential unacceptable conditions should be mitigated.

If overfrequency is likely, the amount of load shed should be reduced or automatic overfrequency load restoration should be provided.

If overvoltages are likely, the load shedding program should be modified (e.g., change the geographic distribution) or mitigation measures (e.g., coordinated tripping of shunt capacitors or reactors) should be implemented to minimize that probability.

If transmission capabilities will likely be exceeded, the underfrequency relay settings (e.g., location, trip frequency, or time delay) should be altered or other actions taken to maintain transmission loadings within capabilities.

Introduction

A special protection system (SPS) or remedial action scheme (RAS) is designed to detect abnormal system conditions and take pre-planned, corrective action (other than the isolation of faulted elements) to provide acceptable system performance. SPS actions, include among others, changes in demand (e.g., load shedding), generation, or system configuration to maintain system stability, acceptable voltages, or acceptable facility loadings.

The use of an SPS is an acceptable practice to meet the system performance requirements as defined under Categories A, B, or C of Table I of the I.A. Standards on Transmission Systems. Electric systems that rely on an SPS to meet the performance levels specified by the **NERC Planning Standards** must ensure that the SPS is highly reliable.

Standards

S1. An SPS shall be designed so that cascading transmission outages or system instability do not occur for failure of a single component of an SPS which would result in failure of the SPS to operate when required.

S2. Misoperation, incorrect operation, or unintended operation of an SPS when considered by itself and not in combination with any other system contingency shall meet the system performance requirements as defined under Categories A, B, and C of Table I of the I.A. Standards on Transmission Systems.

S3. All SPS installations shall be coordinated with other system protection and control schemes.

S4. All SPS operations shall be analyzed for correctness and documented.

Measurements

M1. Each Region whose members use or are planning to use SPSs shall have a documented Regional review process for SPSs to ensure that they comply with Regional criteria and guides and the **NERC Planning Standards**. This review process shall include an SPS database that addresses the design, operation, functional testing of SPSs, and the coordination of the SPSs with other protection and control systems. Documentation of the implementation of the Regional review process shall be provided to NERC on request. (S1, S2)

M2. Each Region shall periodically (at least every five years or as required by changes in system conditions) review and document existing SPSs for compliance with the Regional planning criteria and guides and the **NERC Planning Standards**. This review shall include system studies to evaluate the consequences of: 1) the failure of an SPS to operate due to a single component failure of the SPS, and 2) the misoperation, incorrect operation, or unintended operation of an SPS when considered by itself without any other system contingency.

For all areas of non-compliance, a plan for becoming compliant shall be developed and implemented. Documentation of the compliance review shall be provided to the appropriate Regions and NERC on request. (S1, S2)

M3. New or modified SPSs shall be reviewed for design and functional operation prior to being placed in service. The results of the compliance review shall be documented and provided to appropriate Regions and NERC upon request. (S1, S2)

M4. The design and functional operation of an SPS shall be coordinated and reviewed with affected systems according to Regional compliance review processes. (S3)

M5. Each Region shall have a process for the monitoring, notification, and analysis of all SPS operations. Documentation of SPS failures or misoperations shall be provided to the appropriate Regions and NERC on request. (S4)

M6. Each SPS owner shall have an SPS maintenance and testing program. Documentation of the implementation of SPS maintenance and testing shall be provided to the appropriate Regions and NERC on request. (S1, S2)

Guides

G1. Complete redundancy should be considered in the design of an SPS with diagnostic and self-check features to detect and alarm when essential components fail or critical functions are not operational.

G2. No identifiable common mode events should result in the coincident failure of two or more SPS components.

G3. An SPS should be designed to operate only for conditions that require specific protective or control actions.

G4. As system conditions change, an SPS should be disarmed to the extent that its use is unnecessary.

G5. SPSs should be designed to minimize the likelihood of personnel error, such as incorrect operation and inadvertent disabling. Test devices or switches should be used to eliminate the necessity for removing or disconnecting wires during testing.

G6. The design of SPSs both in terms of circuitry and physical arrangement should facilitate periodic testing and maintenance. Test facilities and test procedures should be designed such that they do not compromise the independence of redundant SPS groups.

A blackout is a condition where a major portion or all of an electrical network is de-energized resulting in loss of electric supply to a portion or all of that network's customer demand. Black-outs will generally take place under two typical scenarios:

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

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

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

The **NERC Planning Standards, Measurements, and Guides** pertaining to System Restoration (IV) are provided in the following sections:

A. System Blackstart Capability
B. Automatic Restoration of Load

These **Standards, Measurements, and Guides** address only two aspects of an overall coordinated system restoration plan. From a planning standpoint, it is critical that any overall system restoration plans include adequate generating units with system blackstart capability. It is also important that adequate facilities are planned for the interconnected transmission systems to accommodate the special requirements of system restoration plans such as switching and sectionalizing strategies, station batteries for dc loads, coordination with underfrequency and undervoltage load shedding programs and Regional or area load restoration plans, and facilities for adequate communications.

Automatic restoration of load following a blackout helps to minimize the duration of interruption of electric service to customer demands. However, these automatic systems must be coordinated with other Regional load restoration activities and included in the components of overall system restoration plans.

Introduction

Following the complete loss of system generation (blackout), it will be necessary to establish initial generation that can supply a source of electric power to other system generation and begin system restoration. These initiating generators are referred to as system blackstart generators. They must be able to self-start without any source of off-site electric power and maintain adequate voltage and frequency while energizing isolated transmission facilities and auxiliary loads of other generators. Generators that can safely reject load down to their auxiliary load are another form of blackstart generator that can aid system restoration.

From a planning perspective, a system blackstart capability plan is necessary to ensure that the quantity and location of system blackstart generators are sufficient and that they can perform their expected functions as specified in overall coordinated Regional system restoration plans.

Standards

S1. A coordinated system blackstart capability plan shall be established, maintained, and verified through analysis indicating how system blackstart generating units will perform their intended functions as required in system restoration plans. Such blackstart capability plans shall include coordination within and among Regions as appropriate.

S2. Each blackstart generating unit shall be tested to verify that it can be started and operated without being connected to the system.

Measurements

M1. Each Region shall establish and maintain a system blackstart capability plan that shall be coordinated, as appropriate, with the blackstart capability plans of neighboring Regions. Documentation of system blackstart capability plans shall be provided to NERC on request. (S1)

M2. Regions shall maintain a record of all system blackstart generators within their respective areas and update such records on an annual basis. The record shall include the name, location, MW capacity, type of unit, date of test, and starting method of each system blackstart generating unit. (S1)

M3. The owner or operator of each system blackstart generating unit shall demonstrate at least every five years, through simulation or testing, that the unit can perform its intended functions as required in the system restoration plan. Documentation of the analysis shall be provided to the Region and NERC on request. (S1)

M4. The results of periodic tests of the startup and operation of each system blackstart generating unit shall be documented and provided to the Region and NERC on request. (S2)

M5. Each Region shall verify that the number, size, and location of system blackstart generating units are sufficient to meet system restoration plan expectations. (S1)

Guides

G1. Analyses should ensure that a system blackstart generating unit is capable of maintaining adequate regulation of voltage and frequency.

G2. Analyses should include evaluation of blackstart generator protection and control systems during the abnormal conditions that will exist during system restoration.

G3. Actual physical testing of system blackstart generating unit procedures should be performed where practical or feasible.

G4. When limited energy resources (e.g., hydro, pumped storage hydro, compressed air) are used for blackstart, the system blackstart capability plan timing considerations should include a range of limiting energy conditions.

Introduction

If properly coordinated and implemented, automatic restoration of load can be useful to minimize the duration of interruption of electric service to customer demands. However, care must be taken to ensure that automatic restoration of load does not impede restoration of the interconnected bulk electric systems.

After automatic load shedding (by either underfrequency or undervoltage relays) has occurred, use of automatic restoration of load after the electric systems have recovered sufficiently (systems stabilized, frequency near nominal, and voltages within appropriate limits) can speed the reenergization of customer demands and minimize delays in restoring the electric systems.

Standard

S1. Automatic load restoration programs shall be coordinated and in compliance with Regional load restoration programs. These automatic load restoration programs shall be designed to avoid recreating electric system underfrequencies or undervoltages, overloading transmission facilities, or delaying the restoration of system facilities and interconnection tie lines to neighboring systems.

Measurements

M1. Those entities owning or operating an automatic load restoration program shall coordinate, document, review, and implement their programs in compliance with Regional programs for load restoration. Documentation of automatic load restoration programs shall be provided to the appropriate Regions and NERC on request. (S1)

M2. Documentation of automatic load restoration programs shall include:

a. A description of how load restoration is coordinated with underfrequency and undervoltage load shedding programs within the Region and, where appropriate, among Regions.

b. Automatic load restoration design details including size of coordinated load restoration blocks (% of connected load), corresponding frequency or voltage set points, and operating sequence (including relay and breaker operating times and intentional delays). (S1)

M3. Each Region shall maintain and annually update an automatic load restoration program database. This database shall include sufficient information to model the automatic load restoration programs in dynamic simulations of the interconnected transmission systems. (S1)

M4. Those entities owning or operating an automatic load restoration program shall conduct and document a technical assessment of the effectiveness of the design and implementation of their programs including their relationship to under-frequency and undervoltage load shedding programs in the Region. Documentation of the technical assessments of automatic load restoration programs shall be available to the appropriate Regions and NERC on request. (S1)

M5. Those entities owning or operating automatic load restoration programs shall have a maintenance program to test and calibrate the automatic load restoration relays to ensure accurate and reliable operation. Documentation of the implementation of the maintenance program shall be provided to the appropriate Regions and NERC on request. (S1)

Guides

G1. Relays installed to restore load automatically should be set with varying and relatively long time delays, except for that portion of the automatic load restoration, if any, that is designed to protect against frequency overshoot.

G2. The design of automatic load restoration programs should consider masystem effects of reenergizing large blocks of customer demand.

G3. Major interconnection tie lines should generally be restored to service before automatic restoration of load is implemented.

References

The references in this section are provided as background information for the users of the **NERC Planning Standards**. This list is comprised of recommendations from the various members of the NERC Engineering Committee's subgroups that participated in the development of the **NERC Planning Standards**.

Except for NERC references, the references in the following list have not been reviewed or endorsed by NERC or any of its subgroups. However, these references should aid the reader who wants an understanding of specific technical areas addressed in the **NERC Planning Standards**.

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Exhibit 2

“Interim NERC Planning Standards” Report

About This Report

The “Interim NERC Planning Standards” report establishes Standards and defines in terms of Measurements the required actions or system performance necessary to comply with the Standards. This report also provides Guides that describe good planning practices for consideration by all electric industry participants.

Mandatory compliance with the NERC Planning Standards is required of the NERC Regional Councils and their members as well as all other electric industry participants if the reliability of the interconnected bulk electric systems is to be maintained in the competitive electricity environment. This report, however, does not address issues of implementation, compliance, and enforcement of the Standards. The timing and manner in which implementation and enforcement of and compliance with the NERC Planning Standards will be achieved have yet to be defined.

In approving the “Interim NERC Planning Standards” report, the EC assigned its Standards and Compliance Task Force (formerly the Standards and Measurement Task Force) to address compliance and enforcement issues associated with this document. The Task Force is to develop a plan of how it intends to proceed with this assignment for review and approval at the November 1997 EC meeting.

Background

At its September 1996 meeting, the NERC Board of Trustees unanimously accepted the report, *Future Course of NERC,* of its Future Role of NERC Task Force — II. This report outlines several findings and recommendations on NERC’s future role and responsibilities in the light of the rapidly changing electric industry environment.

The report also concluded that NERC will carry out its reliability mission by:

- Establishing Reliability Policies, Standards, Principles, and Guides,
- Measuring Performance Relative to NERC Policies, Standards, Principles, and Guides, and
- Ensuring Conformance to and Compliance with NERC Policies, Standards, Principles, and Guides.

In accepting the Task Force’s report, the Board also directed the NERC Engineering Committee and Operating Committee to develop appropriate implementation plans to address the recommendations in the *Future Course of NERC* report and to present these plans to the Board at its January 1997 meeting. The primary focus of the action plans and the initiatives from the Engineering Committee perspective was the development of Planning Standards and Guides. At its January 1997 meeting, the NERC Board of Trustees accepted the Engineering Committee’s November 1996 “Proposed Action Plan to Establish Revised and New NERC Planning Standards and Guides” report. This action plan formed the basis for the development of NERC’s Planning Standards.

Procedure for Planning Standards Development

The preparation and development of the "Interim NERC Planning Standards" report followed the action plan and schedule developed by the EC's Standards and Measurement Task Force. This plan, entitled "Proposed Action Plan to Establish Revised and New NERC Planning Standards and Guides," was approved by the EC in December 1996 and by the NERC Board of Trustees in January 1997.

While the EC's Reliability Criteria Subcommittee had the overall responsibility for the development of the Planning Standards, several other EC subgroups were also instrumental in the development of the Standards:

- Reliability Assessment Subcommittee
- Interconnection Dynamics Working Group
- Multiregional Modeling Working Group
- System Dynamics Database Working Group
- Load Forecasting Working Group
- Available Transfer Capability Implementation Working Group

Because of the developing competitive electricity market and the imminent need for NERC Planning Standards, the approved action plan called for the completion of the Standards in time for review and approval at the July 1997 EC meeting and subsequent review and approval at the September 1997 Board meeting. In addition, the EC requested a review and comment period on all proposed Standards by the Regions and the electric industry prior to their inclusion in any final Standards document that would be presented to the EC for approval. Based on comments received from these interim reviews, a revised draft of the Standards was to be prepared for review and approval at the July 1997 EC meeting. Therefore, the procedure used to develop the Standards can be described as follows:

- Development of Draft Standards

  – RCS and other EC subgroups develop proposed Standards in their assigned areas.

  – RCS, as the Standards coordination group, reviews the proposed Standards developed by the subgroups at an RCS meeting, with the subgroup Chairman in attendance. A preliminary Draft 1 of the proposed Standards is developed.

  – Preliminary Draft 1 of the Standards is distributed back to respective subgroup members for comment. Comments are provided to RCS Chairman and the RCS NERC staff coordinator.

  – RCS Chairman and the RCS NERC staff coordinator, based on comments received, develop the final Draft 1 proposed Standards document.

- Regional and Electric Industry Review of Draft Standards

  – Draft 1 Standards document distributed for Regional and electric industry review. Document is also available on NERC BBS and ftp site.

- Comments on Draft 1 Standards provided to respective Regional and electric industry RCS representatives. RCS representatives bring comments for review and discussion to an RCS meeting. Based on industry comments and further subgroup comments, RCS develops a Draft 2 Standards document.

▪ Revised Draft Standards to EC for Approval

  - Draft 2 Standards document included in agenda for approval at an EC meeting.

  - RCS' s June 20 draft "NERC Planning Standards" report is approved by the EC as an "Interim NERC Planning Standards" reference document.

▪ EC-approved Planning Standards Document to be Presented for Approval at September 1997 Board Meeting

Agenda Item 11b2
BOT Meeting
September 15–16, 1997

Strategic Initiatives for NERC — Standards

Operating Policies and Standards

Four Operating Policies are now in the commenting stage of the Procedures for Developing NERC Standards. The current schedule for implementing these changes follows:

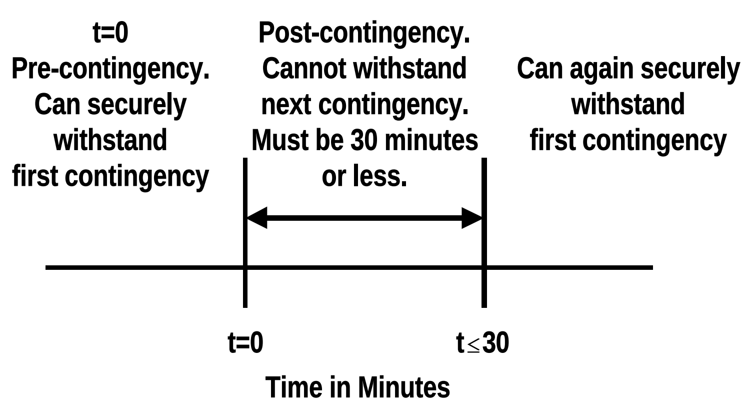
September 19, 1997	Comments due on Policy 5F
October 10, 1997	Comments due on Policies 2, 3, and 4
November 18–19, 1997	Balloting by Operating Committee
January 5–6, 1998	**Approval by Board of Trustees**

Action: None

A brief description of the suggested changes to these Policies follows:

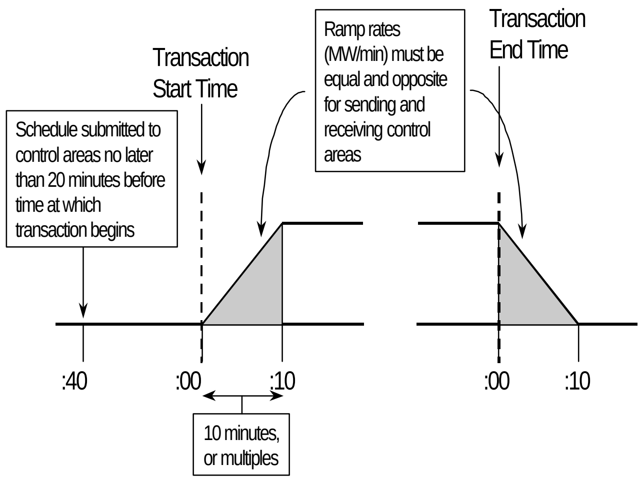
Policy 2 — Transmission

- New Standard on returning the transmission system to within its Operating Security Limits within 30 minutes (see figure).



Policy 3 — Interchange

- Interchange tagging requirement changes.
- Scheduling specifications (see figure).



Policy 4 — System Coordination

- Data required for Interregional Security Network.

Policy 5F — Emergency Operations — Disturbance Reporting

- New reporting requirements to NERC based on reports to DOE.
- Regional follow-up on NERC Disturbance Report recommendations.
- Reporting large generation interruptions to track Interconnection frequency response.

Agenda Item 11b3
BOT Meeting
September 15–16, 1997

Strategic Initiatives for NERC — Standards

Certification and Accreditation

The Operating Committee approved the recommendation from the System Operator Subcommittee to implement programs for NERC System Operator Certification and Training Program Accreditation. The *NERC System Operator Certification Program* will assess system operator core competencies in the areas of NERC Operating Policies and the basic principles of interconnected system operation. The *NERC System Operator Training Accreditation Program* will establish standards for the scope and quality of training provided to system operators. Later this year, the System Operator Subcommittee will recommend new Standards requiring that at least one NERC-certified operator be on duty at all times in every control center.

Who Will be Certified?

The initial target population for the *NERC System Operator Certification Program* will be all system operators who have the primary responsibility, either directly or through communication with others, for the real-time operation and control of interconnected bulk electric systems in accordance with the NERC Operating Policies. System operators in this group work in the control centers of entities such as Control Areas, Transmission Providers, Security Coordinators, Independent System Operators, and other entities with direct responsibility for the operation and security of bulk electric systems.

Funding

The *System Operator Certification Program* is designed to be self-funded through per-candidate fees of $125 to $175 charged when the certification testing is performed.

The costs for the *System Operator Training Accreditation Program* are mostly meeting expenses for the committees that oversee the accreditation process. This Program is expected to begin in 1999.

Action: None

Strategic Initiatives for NERC — Standards

Process for Developing and Approving NERC Standards

At the May 5–6, 1997 Board meeting, the NERC staff reviewed an early draft of a proposed process for developing NERC Standards. The Board approved the "concept" of a new process for developing and approving NERC reliability standards that will provide the opportunity for broad input from all electric market participants and affected parties, and final approval of new or revised standards by a two-thirds majority vote of the NERC Trustees. It also requested that the details of such a new process be presented for approval at its September 1997 meeting.

Subsequent to the Board meeting, the Engineering Committee (EC) and the Operating Committee (OC) approved a draft "due process" procedure presented by the NERC staff at the July 8, 1997 Joint EC/OC meeting as an interim procedure for developing NERC Standards. Presently, four Operating Policies are being reviewed using this interim procedure and which are due for Board approval in January (see Agenda Item 11b2). The procedure relies on the Internet for distribution of draft Policies and Standards and for the collection of comments. Point your Web browser to http://www.nerc.com/standards/.

Comments received from both Committees on the interim procedure have now been reviewed by representatives of the EC, OC, and NERC staff and incorporated into a more refined and detailed draft "Process for Developing and Approving NERC Standards." This proposed process provides for a wide range of input into the development of Standards, opportunities for appeals either on a "due process" or "technical" basis, and interim Standards to be implemented in an emergency (more likely to occur with Operating Standards). It also relies on the Internet for distribution of draft Standards, the collection of comments, and the dissemination of information on the status of Standards development and their approval.

The details of this proposed "Process for Developing and Approving NERC Standards" are attached, and a synopsis will be presented at the Board meeting.

It is recognized that such a process will be ongoing with continual changes. The process is a "work in progress" because the entire process has not been tested.

With the understanding that further changes to the process are highly likely, the Board is requested to approve the proposed new "Process for Developing and Approving NERC Standards" as an interim process to be used in the future for any new or revised NERC Standards.

Action: Approve the proposed "Process for Developing and Approving NERC Standards" as the interim NERC process to be used for any new or revised NERC Standards.

Process for Developing and Approving NERC Standards

Introduction

This document explains the process that NERC has established for announcing, developing, revising, and approving NERC Standards. NERC Standards include NERC Operating Standards and Requirements, and Planning Standards and their associated measurements for determining compliance. The process involves several steps:

- Public notification of intent to develop a new Standard, or revise an existing Standard.
- Subgroup drafting stage.
- Posting of draft Standard for public comment.
- Subgroup review of all comments and public posting of decision reached on each comment.
- NERC Operating Committee or Engineering Committee approval of proposed Standard based on its *technical* merits.
- Appeals Committee resolution of any “due process” or “technical” appeals.
- NERC Board of Trustees (Board) approval of proposed Standard.

The process for developing and approving NERC Standards is generally based on the standard-making procedures used by the American National Standards Institute (ANSI), the Institute of Electrical and Electronics Engineers (IEEE), and the American Society of Mechanical Engineers (ASME):

1. Notification of pending Standard change before a wide audience of all “interested and affected parties,”
2. Posting Standard change drafts for all parties to review,
3. Provision for gathering comments from all parties,
4. Provision for an appeals process — both “due process” and “technical” appeals.

The issues of compliance and enforcement of the NERC Standards are currently under review. It is expected that the results of these activities will identify how the due process procedure described in this document should be modified to accommodate any compliance process.

In cases of expediency, such as in the development of emergency operating procedures, a new or modified Standard may be approved by the Engineering Committee or Operating Committee. Any such Standard must also have an associated termination date should this Standard not be formally approved through NERC’s Standards development and approval process.

Terms

Standards Committee — The Operating Committee or Engineering Committee.

Subgroup — A subcommittee, working group, or task force of the OC or EC, usually where NERC Standards are drafted and posted for review.

Due Process Appeals Committee — The committee that receives comments from those who believe that the "due process" procedure was not properly followed during the development of a Standard. The Due Process Appeals Committee consists of three Board representatives selected by the Board Executive Committee to serve a term of one year. Not more than one representative of the various electric industry sectors, Canada, and end-use customer representatives may serve at the same time on the Due Process Appeals Committee. The NERC Vice President shall be the staff coordinator for the Due Process Appeals Committee.

Technical Appeals Committee — The committee that receives comments from those who believe that their technical comments were not properly addressed during the development of a Standard. The Technical Appeals Committee consists of the vice chairs of the Operating Committee, Engineering Committee, and Board. The NERC Vice President shall be the staff coordinator for the Technical Appeals Committee.

Steps

Step 1 — Request to Revise or Develop a Standard

Requests to revise or develop a Standard are submitted to the Board of Trustees (Board), or to the Standards Committee (NERC OC or EC). Changes to the NERC Standards may be offered by any individual or organization with a legitimate interest in electric system reliability, such as:

- Transmission owners
- Generation owners
- Transmission dependent utilities
- Independent power producers
- Power marketers
- Customers, either retail or wholesale for resale
- NERC subgroups
- Electric industry organizations

Step 2 — Assignment to Subgroup

The Board or Standards Committee then assigns the request to whichever Subgroup(s) are responsible for those issues.

Step 3 — Subgroup Begins Drafting Phase and Announces on Internet

The Subgroup will hold its first meeting to begin working on the new or revised request. If it determines that a new Standard or change in an existing Standard is needed, it announces the pending change and provides a summary of the changes it expects to draft. The announcement will be posted on the NERC Web site and sent to all parties that subscribe to the NERC Standards e-mail list server.

If the Subgroup determines that a new or revised Standard is not needed, it prepares and posts the response to the party that submitted the proposal with a copy to the EC, OC, or Board, as appropriate.

Step 4 — Draft Standard Posted for Comment

The Subgroup will post its first draft of the new or revised Standard on the Internet and provide 45 days for comments. The draft must include specific measurements for determining compliance. Comments on the draft will be solicited from the Regional Councils and all individuals who subscribe to the NERC Standards e-mail list server. A Regional Council member may respond through its Council, or directly, or both. Similarly, members of electric industry organizations may respond through their organizations, or directly, or both. All comments will be accepted but must be supplied electronically. NERC will then post all comments it receives on the Web.

Step 5 — Subgroup Deliberates on Comments

Based on the comments it received, plus its own review, the Subgroup will meet and revise the draft Standard as needed. It will document its disposition of all comments received, and post its decisions on the Web along with its second draft for either further industry review or Standards Committee vote. If the Subgroup believes the technical comments are significant, it will repeat Steps 3 and 4, before sending a revised third draft to the Standards Committee.

The repeat of Steps 3 and 4 is to ensure an adequate review from a "technical" perspective. The number of days for comment on draft 2 of a proposed new or revised Standard will be 45 days, similar to the review period on the initial draft of the Standard.

Parties who have their technical comments on a proposed Standard rejected by a Subgroup may write to the Standards Committee for further consideration of their comments.

Step 6 — Subgroup Submits Draft Standard for Standards Committee Vote

The Subgroup's final draft Standard is posted on the Internet and sent to the Standards Committee for vote. The Subgroup will also determine how the Standard will be addressed for the Standards Committee vote, that is, whether the Standard should be voted on in its entirety or in sections. It will recommend the subdivision of the Standard if the vote is to be taken on individual provisions. Comments on which the Subgroup did not agree are also included.

In general, any "no" votes on a proposed Standard should be accompanied by text explaining the "no" vote and if possible specific language that would make the Standard acceptable. The posting includes an announcement on the Standards e-mail list server with the draft attached and the date of the expected Standards Committee vote. Proposed Standards will be posted no less than 30 days prior to the Standards Committee vote and will also be distributed with the agenda for the Standards Committee meeting.

Step 7 — Standards Committee Votes on Recommendation to Board

At its regular or special meeting, the Standards Committee will discuss and vote on the draft Standard. If the Standards Committee approves the Standard, it sends its recommendation, the draft Standard, and any comments on which the Standards Committee did not agree, plus Standards Committee minority opinions, to the Board for final approval. In general, any "no" votes on a proposed Standard should be accompanied by text explaining the "no" vote and if possible specific language that would make the Standard acceptable.

The Standards Committee action must be posted for a period of 30 days before any vote is taken by the Board. The date of the expected Board vote shall also be posted. The Standards Committee may amend or modify a proposed Standard. The reasons for the modification(s) shall be documented, posted, and provided to the Board. Any parties that object to the modifications may appeal to the appropriate Appeals Committee. These items are all posted on the Internet for general review.

If the Standards Committee does not approve the Standard, it may return the draft to the Subgroup for further work or it may terminate the Standard development activity with the posting of an appropriate notice to the Standards originator, the Subgroup, and the Board (if appropriate).

Step 8 — Appeals Processes

After approval and posting by the Standards Committee, any due process or technical appeals are due to the respective Due Process Appeals Committee or Technical Appeals Committee within 15 days. If an Appeals Committee accepts the appellant's complaint, it rejects the draft Standard and refers the complaint to the Standards Committee or Board for further consideration. If an Appeals Committee denies the complaint, it approves the Standard for referral to the Board. Deliberations of the Appeals Committees shall not exceed 15 days.

Step 9 — Board Approval

At its regular or special meeting, the Board will review and vote on the proposed Standard. It will consider the Standards Committee's recommendations and minority opinions, all comments that were not incorporated into the draft Standard, and inputs from the Due Process and Technical Appeals Committees. To preserve the integrity of the due process Standards development procedure, the Board may not amend or modify a proposed Standard.

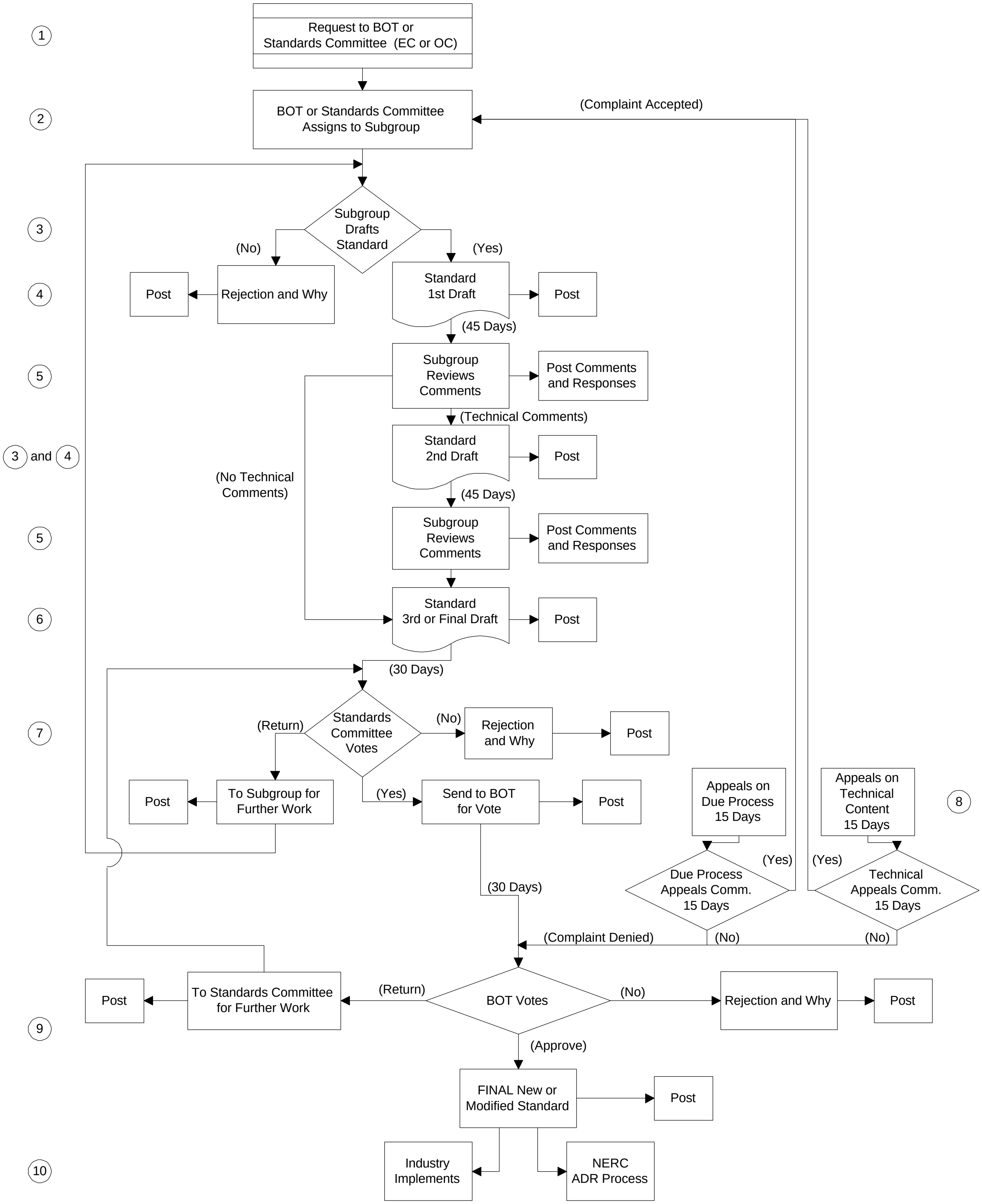
If approved, the Standard is posted on the Web and all parties notified. If the Standard is not approved, the Board may return the Standard to the Standards Committee for further work or it may terminate the Standard activity with an appropriate notice to the Standard originator and Standards Committee. These Board actions will also be posted.

Step 10 — Standard Implementation or Further Appeals

Once a new or modified Standard is approved by the Board, all industry participants are expected to implement and abide by the Standard in accordance with accepted NERC compliance procedures.

Should a party continue to object to the new or modified Standard, that party may request, either through its Regional Council, electric industry organization, or directly, to have the Board consider using NERC's alternative dispute resolution procedure to address its objectives.

Process for Developing and Approving NERC Standards



Agenda Item 11c1
BOT Meeting
September 15–16, 1997

Strategic Initiatives for NERC — Security Process

Transaction Information System ("Tagging")

Tagging began on July 1, 1997, as specified in Operating Policy 3, "Interchange," which the Regions approved on May 1. Despite many opinions that transaction tagging is needed to ensure operational security, the tagging procedure itself has been criticized as unwieldy. After hearing of many startup problems, the OC delayed the requirement for tagging "next day" transactions until July 24, and transactions beginning in four or more hours until August 1. Originally, it was envisioned that the tags were to be faxed to Control Areas and Security Coordinators. However, to avoid the problems of such a volume of faxes and to make the data more useful when it arrived, NERC developed an electronic spreadsheet and automated e-mail software to aid in the tagging process. Refinements of these interim steps are continuing. Development work on specifications for the permanent Transaction Information System has begun and will be one of the topics discussed at the upcoming Transaction Management Workshop.

Interchange Distribution Calculator (IDC)

To assist the Security Coordinators with administering the NERC Transmission Loading Relief Procedure, a "quick start" interim version of the Interchange Distribution Calculator was developed (iIDC). For the iIDC to function properly, all scheduled transactions must be entered into the iIDC database. Also, power transfer distribution factors had to be developed for the entire Eastern Interconnection. Testing of the interim Interchange Distribution Calculator (iIDC) is now under way. Design specifications are being developed for the full IDC, which will be integrated with the Transaction Information System and other systems. Integration of the IDC will be discussed at the upcoming Transaction Management Workshop.

Transaction Management Workshop

NERC will sponsor a workshop on Transaction Management on September 25–26, 1997 in Denver to gather ideas from all participants in electricity markets and build consensus on the proposed NERC Transaction Management System (TMS). The TMS proposes to integrate NERC's Transaction Information (Tagging) System, Interchange Distribution Calculator (IDC), Security Information System (ISN and Next-day systems), Transmission Loading Relief Procedures, and, perhaps, OASIS. This workshop will be a companion to the OASIS workshop, sponsored by the OASIS How Working Group, being held in San Francisco on September 17–18.

Action: None

Agenda Item 11c2
BOT Meeting
September 15–16, 1997

Strategic Initiatives for NERC — Security Process

Interregional Security Network

The Interregional Security Network (ISN) will provide the Security Coordinators with the means to share the myriad electric security data. The "Data" list below is typical of the data that will be shared. The ISN will use a frame relay communications system, and the terminal equipment is now being installed at the nodes listed under "Implementation Schedule."

The cost of the ISN is borne by its users who will pay a base charge plus a data demand charge. The NERC staff will also have a node on the ISN, and the expense for this node is included in the base charge that the ISN users pay. Any special requests or other applications will be charged back to the appropriate party separately.

Data

Transmission Data

Transmission data for all Interconnections plus all other facilities considered key, from a reliability standpoint:

- Status
- MW or ampere loadings
- MVA capability
- Transformer tap and phase angle settings
- Key voltages

Generator Data

- Status
- MW and MVAR capability
- MW and MVAR net output
- Status of automatic voltage control facilities

Operating Reserve

- MW reserve available within ten minutes

Control Area Demand

- Instantaneous

Interchange

- Instantaneous actual interchange with each control area.
- Current INTERCHANGE SCHEDULES with each control area by individual INTERCHANGE TRANSACTION, including interchange identifiers, and reserve responsibilities.
- Interchange schedules for the next 24 hours.

Area Control Error and Frequency

- Instantaneous area control error
- Clock hour area control error
- System frequency at one or more locations in the control area

Other Operating Information Updated as Soon as Available

- Forecast of operating reserve at peak, and time of peak for current day and next day.
- Forecast peak demand for current day and next day.
- Forecast changes in equipment status
- New facilities in place
- New or degraded special protection systems
- Emergency operating procedures in effect
- Severe weather, fire, or earthquake
- Multi-site sabotage

Implementation Schedule

VACAR — CP&L	09/24/97	SERC — Southern	10/07/97
VACAR — Duke Power	09/24/97	MAIN	10/15/97
VACAR — Santee Cooper	09/24/97	SERC — TVA	10/17/97
VACAR — SCE&G	09/24/97	MAPP	10/22/97
VACAR — VA Power	09/24/97	NYPP	11/12/97
NERC Office	09/24/97	SPP	11/12/97
NEPOOL	09/24/97	WSCC	01/07/98
ECAR — AP Back-up	10/01/97	MAAC-PJM	01/15/98
ECAR — AP Primary	10/01/97		

Action: None

Agenda Item 11c3
BOT Meeting
September 15–16, 1997

Strategic Initiatives for NERC — Security Process

Transmission Loading Relief Procedure

In May 1997, the Security Coordinator Subcommittee recommended to the NERC Operating Committee an Interconnection-wide procedure for curtailing transactions to relieve overloading on the transmission system. The OC approved this new NERC Transmission Loading Relief Procedure on an interim basis for implementation this summer in the Eastern Interconnection. The NERC TLRP provides the Security Coordinators with an alternate to existing area or Regional line loading relief procedures.

The TLRP provides an orderly method for relieving overloads on the transmission system through a "share the burden" formula based on distribution factors. (Distribution factors are determined from transmission system computer models. They describe how a power transaction distributes itself over the various paths of the transmission network from generation source to sink.) Should a transmission interface (for example, those transmission lines that connect two control areas) become overloaded, any Security Coordinator can call for the use of the NERC TLRP. When that happens, all transactions contributing 5% or more to the overloaded interface will be reduced in proportion to the flows over the interface. Curtailments are prioritized in accordance with the FERC pro-forma tariff, with transactions arranged with Non-firm transmission service being curtailed in order of length of service. The final transactions curtailed are those served by Firm transmission service. The figure to the right shows the curtailment priority.

Transaction Curtailment Priority

1. **Service over secondary receipt and delivery points**
2. **Hourly Service**
3. **Daily Service**
4. **Weekly Service**
5. **Monthly Service**
6. **Non-firm imports for native load and network customers from sources not designated as network resources**
7. **Firm Service**

The NERC TLRP has been called upon several times this summer by ECAR, MAIN, and SPP, and has generally been successful in relieving the constrained transmission equipment. So far, the Procedure has been coordinated manually through phone calls because not all Security Coordinators are entering the interchange schedules into the Interchange Distribution Calculator. The IDC is capable of calculating the curtailments that are needed to relieve an overloaded transmission facility, but is useless without the interchange schedules. The Security Coordinator Subcommittee has been urging all the Security Coordinators to enter the interchange data.

Action: None

Strategic Initiatives for NERC — Interconnected Operations Services

Interconnected Operations Services

In March 1997, the Interconnected Operations Services Working Group, an all-industry group facilitated by NERC, published its final report, *Defining Interconnected Operations Services Under Open Access*. This report defined the 12 Interconnected Operations Services (IOServices) and explained their relationship to interconnected systems operation.

The Interconnected Operations Services Implementation Task Force has now been formed by NERC to address each of the final report's recommendations to NERC (Exhibit 1), and develop and recommend Standards related to Interconnected Operations Services for review and approval by the NERC Engineering Committee and Operating Committee and Board of Trustees.

The proposed Standards will be designed to apply to entities connected to, exercising control of, or making use of the Interconnections. The Standards will address:

- The rules or processes for measuring or judging the characteristics of IOServices [Planning Standards].
- Required practices (including information requirements) and accountabilities of IOService providers and customers, marketers, and operating entities to ensure necessary IOServices are procured, deployed and delivered in the operational timeframe [Operating Standards].
- Compliance monitoring requirements (in concert with the OC Compliance Subcommittee and the EC Standards and Compliance Task Force).
- The concepts of community and individual services, secondary reserve planning and Interconnection requirements proposed in the IOSWG report.

Membership

Membership will include representatives from:

- all NERC Regions
- all electric industry sectors
- the NERC Engineering Committee and Operating Committee, or their appropriate subgroups
- the former IOSWG
- the electric industry's Commercial Practices Working Group

Process

The Task Force shall:

- Employ the NERC process for soliciting and responding to industry comments through the Procedures for Developing NERC Standards.
- Monitor the progress of, and coordinate its activities with, related industry initiatives including the NERC Performance Subcommittee and the EPRI project addressing the measurement of IOServices.
- Coordinate with the Operating Committee's Compliance Subcommittee and the Engineering Committee's Standards and Compliance Task Force, as appropriate, regarding compliance measurements of Interconnected Operations Services.

Reporting

The Task Force shall report to the NERC EC and OC. Its products shall be aligned with EC/OC responsibilities to streamline the review and approval process.

Timetable

November 18–19, 1997	Proposed plan for development of IOS Standards and status of Task Force activities	EC and OC meetings
December 10–11, 1997	EPRI Workshop on Ancillary Services (Task Force to participate)	Miami
March 10–11, 1998	Status report of Task Force activities	EC and OC meetings
July 14–15, 1998	EC and OC approval of draft IOS Standards	EC and OC meetings
September 14–15, 1998	Board approval of IOS Standards	Board of Trustees meeting

Exhibit 1

Recommendations to NERC from "Defining Interconnected Operations Services Under Open Access," March 7, 1997, Interconnected Operations Services Working Group, pp 15–16

The IOSWG recommends that NERC:

- Translate the IOS technical framework into NERC Operating and Engineering policies. Of particular significance, the policies must contain measurable standards, compliance requirements, and enforcement mechanisms applicable to all entities connected to, exercising control of, or making use of the grid.

- Address the development and standardization of interconnection requirements, such as minimum power factor and emergency load curtailment plans.

- Schedule a joint IOSWG/NERC series of meetings to:

  — Provide clarification on the IOS technical framework

  — Formalize plans and establish work teams to develop NERC IOS Operating and Engineering Policies and Standards

- Endorse the concept of a Secondary Reserve plan and develop a plan for its implementation.

- Provide for and maintain a NERC IOS reference document.

Agenda Item 12
BOT Meeting
September 15–16, 1997

<u>Reliability Assessment Subcommittee</u>

a. Reliability Assessment 1997–2006

The final draft of the *Reliability Assessment 1997–2006* report, which has the approval of the Engineering Committee and the endorsement of the Operating Committee, will be submitted for approval by the Board under separate cover. Robert W. Cummings, Reliability Assessment Subcommittee Staff Coordinator, will present the highlights of the report.

Action: Approve the *Reliability Assessment 1997–2006* report for publication.

b. Revised Subcommittee Scope

At its July 8–9, 1997 meeting, the Engineering Committee approved a revised scope for the Subcommittee (Exhibit 1), which incorporates the Subcommittee's new assignment of preparing NERC's summer and winter seasonal assessments and provides for the development of an assessment "procedural manual."

Action: Approve new scope for Reliability Assessment Subcommittee.

Exhibit 1

Scope of the
Reliability Assessment Subcommittee
of the
NERC Engineering Committee
(Proposed)

Purpose

The Reliability Assessment Subcommittee (RAS) reviews, assesses, and reports on the overall reliability (adequacy and security) of the Regional (subregional) and interregional bulk electric systems, both existing and as planned. Those reviews and assessments verify that each Region (subregion) conforms to its own planning criteria and guides and NERC's Planning Standards.

Reliability Assessment Subcommittee Review and Assessment Process

The Reliability Assessment Subcommittee Review and Assessment Process is described in the Reliability Assessment Subcommittee Procedural Manual (to be prepared by RAS and approved by the Engineering Committee, November 1997).

Scope of Activities

1. Evaluate if Regional (subregional) bulk electric systems conform to their respective Regional (subregional) planning criteria and guides and NERC's Planning Standards over the assessment period.

2. Annually review and assess the overall reliability (adequacy and security) of the Regional (subregional) and interregional bulk electric system plans over a ten-year horizon and report results to NERC's Engineering Committee, Operating Committee, Board of Trustees, and the public.

3. Seasonally (summer and winter) review and assess the overall reliability (adequacy and security) of the Regional (subregional) and interregional bulk electric systems from an operational planning perspective, and report results to NERC's Engineering Committee, Operating Committee, Board of Trustees, and the public.

4. Review and recommend modifications, as necessary, to the Reliability Assessment portion of the NERC Planning Standards.

5. Develop and maintain a RAS Procedural Manual, and recommend modifications for approval as necessary. That Manual includes the RAS Reliability Review and Assessment Process, the RAS data reporting schedule and requirements, and the report preparation, approval, and publication schedules for RAS reports.

6. Address and resolve with a Region(s) any potential Regional and interregional reliability issues or differences between the Subcommittee's assessment and that Region's internal or interregional reliability assessment(s). Report any unresolved issues or differences to the NERC Engineering Committee.

7. Conduct periodic reviews of activities, practices, policies, and studies, as assigned by the Engineering Committee, relating to reliability on a Regional, interregional and Interconnection basis, and report results to the Engineering Committee, as appropriate.

Data Submittal

The RAS shall collect demand, capacity, and transmission data, and other pertinent information necessary to assess the reliability of the interconnected bulk electric systems. The data submittal schedule and reporting requirements are contained in the RAS Procedural Manual.

Representation

The Subcommittee is comprised of the following:

- Chairman
- Vice Chairman
- One representative from each Regional Council
- One representative from the NERC Operating Committee
- Member-at-large representing Canada
- Representatives from all other industry segments
- NERC staff coordinator

Liaison Members include:

- Alaska Systems Coordinating Council (NERC Affiliate)
- United States Department of Energy

The Subcommittee Chairman and Vice Chairman are appointed by the Chairman of the Engineering Committee for two-year terms. The Vice Chairman should be available to succeed to the chairmanship.

The Operating Committee representative is appointed by the Chairman of the Operating Committee for a two-year term.

All other Subcommittee members are appointed by their Region or industry segment for two-year terms.

Reporting

The Subcommittee is responsible to the Engineering Committee. The Subcommittee Chairman will report periodically to the Engineering Committee, Operating Committee, and Board of Trustees, as required.

Approved by the Engineering Committee: July 8, 1997

Approved by the Board of Trustees: September __, 1997

1998 Budget

Mr. James J. Jura, Chairman of the Budget Committee, and NERC's Secretary-Treasurer, will present the 1998 Budget and Regional Assessments for Board approval. The 1998 recommended Budget, which includes a "Special Projects" Budget and a General Budget, is $4,046,851. The 1998 Proposed Budget is approximately 10% less than 1997. An annotated Budget Summary and a table of approximate Regional Assessments is included. The more detailed working document used by the Budget Committee is available on request.

The 1998 Special Budget has funding only for those projects that have been approved by the Board. Additionally, several major projects are assumed to become fully or partially self-supporting. The Budget Committee recognizes that our commitment to the implementation of the Strategic Initiatives, that will ensure reliable Interconnections in the new era of open access and increased competition, may find our technical committees proposing projects during 1998 that will require additional funding.

The General Budget expenses are expected to increase about 5%. The major cost category of this Budget is salaries and associated costs (58%). For Budget purposes, a 4% increase has been used. Three new staff members were added during 1997, accounting for the distorted percentage increases on the chart. No additional staff is anticipated in the 1998 Budget. The second largest category of the General Budget, Travel and Meetings (25%) shows a slight decrease. This category will be driven by the need to respond to FERC initiatives. The remainder of the General Budget (17%), which includes office space and costs, increases 7% primarily due to a small increase in office space and a rent increase.

Action: Approve a 1998 NERC Budget of $4,046,851 (total of General and Special Projects Budgets) and Regional Assessments of $4,046,851.

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

1998 PROPOSED BUDGET

Prepared by NERC staff for the Budget Committee:

James J. Jura (Chairman)
Howard Hawks
Jack Davis

Presented to Board of Trustees
September 16, 1997

TABLE 2
PROJECTED RECEIPTS AND EXPENSES
YEARS ENDING 1997[1] AND 1998

	1997	1998
Projected Receipts		
Assessments, Regions	$4,500,000	$4,041,851
Assessments, ASCC	5,000	5,000
Total Receipts	$4,505,000	$4,046,851
Projected Net Expenses		
General Budget	$3,046,608	$3,247,024
Special Budget	1,475,946	799,827
Total Net Expenses	$4,522,554	$4,046,851
Excess Receipts over Expenses	(17,554)	(0)
Fund Balance, Beginning	$434,373	$416,819
Fund Balance, Ending	416,819	416,819

TABLE 3
COMPARISON OF PREVIOUS BUDGETS, ASSESSMENTS, AND YEAR ENDING FUND BALANCES

Year	Base Budget[2]	Percent Increase[3]	Special Projects Budget	Regional Assessment	Percent Increase	Ending Fund Balance	Percent of Base Budget
1982	$1,610,332			$1,610,332		$339,266	20.6
1983	1,643,177	2.0	—	1,643,177	2.0	472,660	28.1
1984	1,680,000	2.2	—	,643,177	0.0	564,696	31.9
1985	1,771,200	5.4	—	1,725,336	5.0	674,666	37.1
1986	1,818,000	2.6	—	1,775,000	2.9	677,252	35.4
1987	1,913,750	5.3	—	1,876,750	5.7	730,132	37.7
1988	1,934,890	1.1	—	1,876,750	0.0	726,011	35.7
1989	2,030,977	5.0	—	1,945,000	3.6	328,550	15.1
1990	2,181,459	7.4	—	2,534,909	30.3	757,363	33.8
1991	2,308,260	5.8	—	2,199,963	-13.2	871,047	37.7
1992	2,406,133	4.2	—	2,256,017	2.5	821,098	34.1
1993	2,323,142	-3.4	—	2,075,300	-8.0	618,680	26.6
1994	2,432,496	4.7	—	2,417,129	16.5	586,886	24.1
1995	2,419,400	-0.5	—	2,403,295	-0.6	599,270	24.8
1996	2,610,773	7.9	—	2,500,000	4.0	434,373	16.6
1997	2,740,276	5.0	$1,800,000	4,500,000	80.0	416,819	15.2
1998	3,247,024	18.5	799,827	4,041,851	-10.2	416,819	12.8

[1]Receipts and Expenses for 1997 projected through end of year, as of May 31, 1997.
[2]Net Expenses (Base Budget only).
[3]Percent increase in Base Budget.

TABLE 4
TOTAL ASSESSMENTS

Region	Annual NEL[1]	PRO-Rata Share	Equal Share	Total 1998 Assessments
ECAR	521,247	$305,636.92	$204,224.55	$509,861.47
ERCOT	231,440	97,247.63	193,564.55	290,812.18
FRCC	169,021	99,106.51	204,224.55	303,331.06
MAAC	243,043	142,509.87	204,224.55	346,734.42
MAIN	224,380	131,566.68	204,224.55	335,791.23
MAPP	177,891	104,307.50	204,224.55	308,532.05
NPCC	583,016	341,855.65	204,224.55	546,080.20
SERC	572,587	335,740.52	204,224.55	539,965.07
SPP	295,169	173,074.35	204,224.55	377,298.90
WSCC	689,885	289,879.87	193,564.55	483,444.42
Region	3,707,679	$2,020,925.50	$2,020,925.50	$4,041,851.00

[1]Actual Assessments will be based on 1997 NEL

Discussion

Proposed 1998 General and Special Projects Budget

After five years of less than 3% year-to-year Budget growth, the NERC Board authorized an additional assessment to the 1997 NERC Budget of $1.8 million to fund projects associated with opening access to the transmission systems in preparation for a more competitive electricity environment. This 67% Budget increase signaled a higher profile and more active role for NERC and the Regional Councils in carrying out their mission of assuring reliability.

For 1998, the total proposed Budget, $4,046,851, is 10% less than the approved Budget for 1997. However, the Budget Committee points out that our commitment to a network of Security Coordinators to protect the reliability of the Interconnections, tools for the Security Coordinators, a new Standards Process for NERC, and the training needed to support these tasks will likely keep the needed funding at this higher level for the foreseeable future. In addition, these Special Projects are all in the development and implementation stage, and the committees are likely to continue to make recommendations after this Budget is approved that will affect spending during this period.

The 1998 Budget is presented in two parts, a Special Projects Budget and a General Budget. The Special Projects Budget covers those projects developed through the committee processes and approved by the Board. The associated proposed expenses have also been developed by the responsible committees, subcommittees, or task forces. The General Budget covers NERC staff and NERC office facilities. The staff costs of supporting the Special Projects are generally included in the General Budget for 1998, but will be functionally allocated in future Budgets.

1997 Actual Expenses

A preliminary budget for 1997 was presented to the Board in May 1996 with the understanding that the activities undertaken by NERC on behalf of the electric industry in response to the FERC open access rule were escalating. The Board approved a 1997 NERC Budget of $2,740,276 plus a nominal “special projects” Budget of $300,000 for a total of $3,040,276 at its September 1996 Board meeting. The two major unknowns at that time were the possibility of new legislation and the extent of the additional initiatives that the Future Role of NERC Task Force — II (FRNTF) expected to bring to the Board. Greg Nesbitt, Chairman of the Budget Committee and Secretary-Treasurer of NERC, indicated that his Committee knew this was not sufficient and they would come back to the Board for additional “Strategic Initiatives” funding in January to coincide with the recommendations expected from the FRNTF. The Board authorized assessments of $3,000,000 in September 1996 and an additional $1,500,000 in January 1997. The Board also acknowledged that the full $1.5 million for Special Projects may not be needed in 1997.

Summary of 1997 Net Expenses and 1998 Proposed Budget

	1997 Approved	1997 Projected	1998 Proposed
General Budget	$2,740,276	$3,046,608	$3,247,024
Special Projects*	300,000		
Strategic Initiatives	1,500,000	1,475,946	799,827
TOTAL	$4,540,276	$4,522,554	$4,046,851

* "Special Projects" covers the cost of two additional consultant employees. This expense is initially shown separately broken out because this was the way the expense was approved in September 1996. For the Budget presentation, it will be combined with "Strategic Initiatives," making the approved "Special Projects" equal $1,800,000 and the total 1997 Budget $4,540,276.

At mid-year, it appears that about $325,000 of the $1.8 million total Special Projects authorization will not be spent. This includes the commitment by the Board in May 1997 to additional costs for the Blue Ribbon Reliability Panel Study (+$206,000).

Special Projects Budget

	1997 Approved	1997 Projected	1998 Proposed
Certification/Accreditation	$ 336,588	$ 352,161	$ 0
Transaction Management	500,450	345,380	298,500
ISN	269,100	196,167	250,000
Standards	248,862	179,426	201,327
Blackout Response	270,000	15,000	50,000
Reorganization	175,000	387,812	0
Total Strategic Initiatives	$1,800,000	$1,475,946	$799,827

Certification/Accreditation

The purpose of the Certification Program is to establish a minimum level of competence required of system operators responsible for reliable operation of all control areas, regional security centers, and ISOs. The scope of the certification testing process is limited to basic principles of interconnected systems operations and NERC Operating Policies. Within three years of implementing the NERC-wide Certification Program, all control areas and other subject entities will be required to be continuously manned by at least one Certified System Operator. The purpose of the Accreditation Program is to ensure that all training programs which provide initial, extended or advanced, and continuing training for system operators engaged in operating the interconnected systems shall provide effective instructional programs, including one to prepare for the NERC System Operator Certification examination.

The 1997 Budget called for issuing an RFP and hiring a contractor to develop a proposal for a program that would withstand the rigors of The National Association of Certifying Agencies. The process took longer than anticipated, but will come in under the original Budget. The 1998 Budget assumes that the program will be self-funded through a per candidate test fee.

Transaction Management

This “program” covers the cost to develop tools for the 22 Security Coordinators. The tools include the Interchange Distribution Calculator (IDC), used to predetermine the effect of interchange transactions on all transmission paths, the Transaction Information System (TIS) or energy tagging system, the Transmission Loading Relief (TLR) program that uses the IDC information and the “tags” to assist the Coordinators to back off dangerous transmission loading conditions to ensure reliability, and a prototype Transmission Reservation and Scheduling program.

In the early spring, the Security Coordinator Subcommittee and their support team, the SPSSTF, decided that the pending summer conditions warranted the quick development of interim tools. We now have in place and are testing an interim IDC (iIDC), an interim tagging system (iTIS), and an interim TLR program. A symposium is scheduled for September and eight Tagging/OASIS workshops have already been held at varying locations. Self-directed work teams have held more than 50 meetings to accomplish these tasks. Ontario Hydro, Southern Company, Commonwealth Edison, and others have contributed to the programming. Over one-half of the $345,000 “actual” cost in 1997 has been for the consultant employees that are helping to manage these projects. The majority of the expenses anticipated in the 1998 Budget are for follow-on developmental work. A fully automated and integrated IDC, TIS, TLR, and TRS will be a substantial commitment that will be presented to the Board with funding requirements some time in 1998.

Interregional Security Network

The RFP for a frame relay communications system to support the System Coordinators drew three bids. A task force of experts selected Intermedia Communications Inc., of Tampa as NERC’s provider. A contract has been negotiated and the system goes on-line in September, later than anticipated, but at a lower cost. The task force has also decided on a funding mechanism that is almost Budget neutral for our purposes. The NERC costs for this program reflect a Network Administrator and part of one of our consultant/employee’s time for both the 1997 Actual and the 1998 Proposed Budget.

Standards

1997 Actual costs are for parts of both of our consultant employees and the cost of a Standards Administrator that we anticipate requiring by the end of the year. The 1998 Budget is for the permanent Administrator, travel, and legal. The Board will have continuing opportunities to shape the “open process” approach as we develop NERC’s standards through practical experience.

Blackout Response

This program was initiated after the WSCC blackouts in 1996 summer. NERC responded quickly to DOE. The 1997 Budget reflects the best estimates at that time of fulfilling our obligations as detailed in the August 1996 DOE report to the President. Most of the expenses anticipated in 1997 centered on the need to study voltage collapse and the development of a media relations program for NERC that would be integrated with the programs in the Regions. BPA took the lead on a voltage study using a panel of experts to oversee the project, including NERC's Virginia Sulzberger. This has reduced the urgency of the need for NERC to study voltage collapse. The other tasks of this project have also been deferred. The 1998 Budget carries over an allocation for a “recommendations tracking system” as recommended in DOE’s report. Most of the other activities can be integrated into the other Special Projects or the General Budget.

Reorganization

The Board accepted the idea of a “reinventing NERC” study along the lines recommended by the Compliance Team in their “Options to Ensure Compliance” report. The original study was conceived to be much smaller than what the Board eventually approved in May 1997. No expenditures are provided for in 1998.

General Budget

In total, the General Budget proposed for 1998 has expenses increasing 4.9%, and when income from sales and services is included, increasing 6.6%. Actual 1997 expenses will be greater than the 1997 General Budget, principally due to new employees. After ten years of no increases in the number of people, the workload finally overwhelmed the staff. The new activities introduced in the past two years include: new mandatory operating and planning standards, FERC rules, Congressional hearings, and FERC Technical Conferences, DOE’s Reliability Task Force, transmission reservation and scheduling, the Security Coordinator function, development and management of “confidentiality agreements,” new data collection and distribution systems, and the responsibility for OASIS and TIS registration. The staff has grown to 24 from the steady 20 of the last decade. No additional employees are provided for in the 1998 Budget.

The largest category in the General Budget is Salaries, constituting 58% of all General Budget expenses. Because of hiring at mid-year, the calendar year comparison of Actual 1997 to 1998 Budget of 9.4% is deceiving. For Budget purposes, Salaries are increased in the 1998 Budget by 4%.

The second largest expense category is Travel and Meetings. Over 50 additional meetings have or will occur in 1997. The 1998 Budget anticipates a slight moderation of that meeting schedule.

When Employee Costs, including Salaries, are combined with Travel and Meetings, they constitute about 83% of the General Budget. The remaining 17% is for Office Costs and Report Expenses. This remaining part has an increase of about 7% due to a small increase in office space.

More details are available in a 29-page Budget Committee working document upon request.

TABLE 1

Summary of Expenses and Income -- 1998 Budget

North American Electric Reliability Council

	(1) 1997 Budget	(2) 1997 Actual	(3) 1998 Budget	(2) vs. (1)	(3) vs. (2)	(3) vs. (1)
INCOME						
rental	$7,700	$7,865	$9,100	2.1%	15.7%	18.2%
internet	10,000	59,227	40,000	492.3%	-32.5%	300.0%
interest	30,000	38,102	30,000	27.0%	-21.3%	0.0%
copying	250	222	250	-11.2%	12.6%	0.0%
reports	31,300	32,139	23,750	2.7%	-26.1%	-24.1%
services & software	80.500	86,321	80,500	7.2%	-6.7%	0.0%
Total Income	159,750	223,876	183,600	40.1%	-18.0%	14.9%
EXPENSES (NON-PERSONNEL)						
rent & improvements	204,006	235,892	271,960	15.6%	15.3%	33.3%
office costs	231,785	220,065	228,893	-5.1%	4.0%	-1.2%
furniture & equipment	4,500	26,813	4,500	495.8%	-83.2%	0.0%
report expenses	100,790	87,335	84,300	-13.3%	-3.5%	-16.4%
computer	87,500	112,361	90,500	28.4%	-19.5%	3.4%
travel meetings	294,500	345,184	328,500	17.2%	-4.8%	11.5%
programs	23,000	8,368	23.000	-63.6%	174.9%	0.0%
Total Non-Personnel Expenses	946,081	1,036,018	1,031,653	9.5%	-0.4%	9.0%
EXPENSES (PERSONNEL)						
salaries	1,607,065	1,822,366	1,994,183	13.4%	9.4% *	24.1%
employee costs	243,500	288,809	284,992	18.6%	-1.3%	17.0%
savings & retirement plans	75,880	77,869	87,296	2.6%	12.1%	15.0%
services	27,500	45.422	32,500	65.2%	-28.4%	18.2%
Total Personnel Expenses	1,953,945	2,234,466	2,398,971	14.4%	7.4%	22.8%
Total All Expenses	2,900,026	3,270,484	3,430,624	12.8%	4.9%	18.3%
Total General Budget	$2,740,276	$3,046,608	$3,247,024	11.2%	6.6%	18.5%
SPECIAL BUDGET						
certification/accreditation	$336,588	$352,161	$0	4.6%	-100.0%	-100.0%
transaction management	500,450	345,380	298,500	-31 .0%	-13.6%	-40.4%
interregional security network	269,100	196,167	250,000	-27.1%	27.4%	-7.1%
standards	248,862	179,426	201,327	-27.9%	12.2%	-19.1%
blackout response	270,000	15,000	50,000	-94.4%	233.3%	-81.5%
reorganization	175,000	387,812	0	121.6%	-100.0%	-100.0%
Total Special Budget	1,800,000	1,475,946	799,827	-18.0%	-45.8%	-55.6%
TOTAL BUDGET	$4,540,276	$4,522,554	$4,046,851	-0.4%	-10.5%	-10.9%

* Compares 24 employees for 12 months w/ 21 for 5 mo.plus 24 for 7 mo. in 1997. Annualized = 4%

Agenda Item 15
BOT Meeting
September 15-16, 1997

Future Meetings

The following dates and locations have been approved for future Board of Trustees meetings:

January 5-6, 1998	(M-T)	Scottsdale, Arizona Scottsdale Princess
May 4-5, 1998	(M-T)	New Orleans, Louisiana Hotel Inter•Continental
September 14-15, 1998	(M-T)	Ottawa, Ontario
January 4-5, 1999	(M-T)	Scottsdale, Arizona

Action: Approve May 10-11, 1999 in Dallas, Texas