NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

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

Resources Subcommittee Meeting

Wednesday, May 3, 2006 — 8 a.m.–5 p.m.
Thursday, May 4, 2006 — 8 a.m.–5 p.m.
Friday, May 5, 2006 — 8 a.m.–noon

Marriott-Baltimore-Washington International Airport
1743 West Nursery Street
Baltimore, Maryland 21240
Phone: 410-859-8300

Agenda

1. Administrative

a. Membership and Guests — Chair
b. Arrangements — Secretary
c. Approval of February 8–10, 2007, Meeting Minutes — Chair
d. Procedures
   i) Parliamentary Procedures — Chair
   ii) Antitrust Compliance Guidelines — Chair
e. Resources Subcommittee Action Items List — Chair

2. Task Force Reports

a. Control Criteria Task Force — Alan Oneal
b. Frequency Task Force — Raymond Vice
c. Inadvertent Interchange Task Force — Don Badley
d. Operating Reserves Task Force — Larry Akens

3. NERC Reliability Standards

a. Standard BAL-004-0, Time Error Correction — Don Badley
b. Standard BAL-005-0, Automatic Generation Control — Raymond Vice
c. Standard BAL-006-0, Inadvertent Interchange – Don Badley
d. Reference Document –
   i) Performance Standards Reference Document — Alan Oneal
   ii) Training Document – Area Interchange Error Survey Training Document — Don Badley
   iii) Training Document – Frequency Response Characteristic Survey — Raymond Vice
   iv) Training Document – Inadvertent Interchange Accounting Training Document — Don Badley
e. Balance Resources and Demand Draft Standard Update — Raymond Vice
f. Frequency Response SAR – Terry Bilke

4. NERC Active Resources Subcommittee Projects — Status

a. ACE-Frequency Application Project (Project 2000-03) — Carlos Martinez
b. AIE Monitoring Application Project (Project 2000-4) — Carlos Martinez
c. CPS1 & BAAL Monitoring Application Project (Project 2001-38) — Carlos Martinez
d. Frequency-Phasor Monitoring Application Project (Project 2005-6) — Terry Bilke, Carlos Martinez
e. Inadvertent Interchange Application Project (SPP inadvertent interchange tool migration) (Project 2001-37) — Carlos Martinez
f. DOE Eastern Interconnection Phasor Project (EIPP) — Terry Bilke, Carlos Martinez

5. Frequency Performance

a. Western Interconnection Frequency Trends
b. Eastern Interconnection Frequency Trends
c. ERCOT Frequency Trends
d. CPS1, CPS2, BAAL Data Trends
e. DCS Data Trends
f. Inadvertent Interchange Balances — Joe Emde, Don Badley, Terry Bilke
g. Potential Joint Meeting with the ORS, RCWG, and IS

6. Time Error

a. Eastern Interconnection — Bill Herbsleb
b. Western Interconnection — Don Badley
c. ERCOT Interconnection — Sydney Niemeyer

7. Future Meetings

a. September 20–22, 2006 — Québec City, QU
b. November 15–17, 2006 — Ft. Lauderdale, FL

Item 1. Administrative

Item 1.a Membership and Guests

Chairman Terry Bilke will welcome the Resources Subcommittee members and guests. The chair will ask members and guests to introduce themselves.

Each member is asked to check and review the current organization, roster, and survey contacts list for accuracy.

NERC staff asked the Canadian Electricity Association to nominate at least two Canadian representatives to the Resources Subcommittee.

Attachments

1. Resources Subcommittee Organization
2. Resources Subcommittee Roster
3. Resources Subcommittee Survey Contacts List

Item 1.b Arrangements

The Resources Subcommittee task forces meetings will be held on Wednesday, May 3, from 8 a.m. to 5 p.m. The Resources Subcommittee meeting will begin on Thursday, May 4 at 8 a.m. and adjourn by noon on Friday, May 5, 2006. Lunch will be served on Wednesday and Thursday.

Item 1.c Approval of February 8–10, 2006 Meeting Minutes

The chair will ask for approval of the February 8–10, 2006 Resources Subcommittee meeting minutes.

Attachment

February 8-10, 2006 Resources Subcommittee Meeting Minutes

Item 1.d Procedures

Item 1.d.i. Parliamentary Procedures

A summary of Parliamentary Procedures is attached for reference. The chair will answer questions regarding these procedures.

Item 1.d.ii. Antitrust Compliance Guidelines

On June 14, 2002, the NERC Board of Trustees adopted Antitrust Compliance Guidelines for NERC. In adopting the guidelines, the board passed the following resolution:

RESOLVED, that the Board of Trustees (1) adopts the draft Antitrust Compliance Guidelines attached hereto as Exhibit A and (2) instructs that these Antitrust Compliance Guidelines be included in the agenda package for each meeting of every NERC committee, subcommittee, task force, working group, and other NERC-sponsored activity.

The resolution also applies to workshops, training sessions, and any other NERC-sponsored event. A copy of the NERC Antitrust Compliance Guidelines will be included in the agenda package for each meeting of each group or event.

Attachments

1. Parliamentary Procedures
2. Antitrust Compliance Guidelines

Item 1.e Resources Subcommittee Action Items List

Discussion

The chairman will discuss the tasks, issues, concerns, projects, etc. that fall within the subcommittee's purview. The goal is to identify, prioritize, and establish completion dates (i.e., near-, mid-, and long-term time frames) for these items. Some issues will need collaboration with other groups such as the Reliability Coordinator Working Group, Interchange Subcommittee, Interconnections, regions, balancing authorities, or the Consortium for Electric Reliability Technology Solutions (CERTS).

Attachment

Resources Subcommittee Action Items List

NERC Resources Subcommittee
Organization and Assignments

Larry Akens Tennessee Valley Authority	Donald E. Badley **(Vice Chairman)** WECC/Northwest Power Pool	Gerald D. Beckerle Ameren Services Company
Terry Bilke (Chairman) Midwest ISO	Randy M. Jones Calpine Power Service Corporation	Don McInnis Florida Power & Light Company
Robert C. Rhodes, Jr. Southwest Power Pool	Alan R. Oneal MidAmerican Energy Company/MRO	Bart McManus Bonneville Power Administration
William Herbsleb PJM Interconnection, L.L.C.	Sydney L. Niemeyer TxGenco	Michael J. Potishnak ISO-New England
John Swez Cinergy Corp.	John Tolo Tucson Electric Power Company	Raymond L. Vice Southern Company Services, Inc.
Thomas J. Vandervort NERC		

Inadvertent Task Force	**Frequency Task Force**	**Reserves Task Force**
Don Badley Mike Potishnak Terry Bilke Randy Jones Larry Akens Bart McManus	**Raymond Vice** Sydney Niemeyer Raymond Vice Mike Potishnak Terry Bilke Gerry Beckerle Don Badley Bart McManus John Swez	**Larry Akens** Alan Oneal Don Badley Raymond Vice Mike Potishnak Sydney Niemeyer Robert Rhodes Bart McManus John Tolo John Swez
Compliance Task Force	**Control Criteria Task Force**	
Bill Herbsleb John Tolo	**Alan Oneal** Resources Subcommittee	

Survey Assignments

Area Interchange Error Surveys (East)	Terry Bilke
Frequency Response Surveys	Raymond Vice
Inadvertent Interchange Reports (East)	Joe Emde
Inadvertent Interchange Reports (West)	Don Badley
Time Error Reports (East)	Bill Herbsleb
Time Error Reports (West)	John Tolo
ERCOT Reports	Sydney Niemeyer

May 2006

Resources Subcommittee

Chairman	Terry Bilke Technical Manager	Midwest ISO, Inc. 701 City Center Drive Carmel, Indiana 46032	(317) 249-5463 (317) 249-5910 Fx tbilke@ midwestiso.org
Vice Chairman	Donald E. Badley System Operations Manager	Northwest Power Pool 26 S.W. Salmon Street Suite 400 3WTC0402 Portland, Oregon 97204-2991	(503) 464-2805 (503) 464-2819 Fx don@nwpp.org
ERCOT	Sydney L. Niemeyer Control System Specialist	Texas Genco, LP 1301 McKinney Suite 2300 Houston, Texas 77010	(713) 795-6108 sydney_l_niemeyer@ txgenco.com
FRCC	Don McInnis Manager, Operations Engineering	Florida Power & Light Co. P.O. Box 029311 Miami, Florida 33102-9311	(305) 442-5272 don_mcinnis@ fpl.com
MRO	Alan R. Oneal Director, Trading Operations	MidAmerican Energy Co. 4299 N.W. Urbandale Drive Urbandale, Iowa 50322	(515) 252-6449 (515) 252-6446 Fx aroneal@ midamerican.com
NPCC	Michael J. Potishnak Principal Engineer	ISO New England, Inc. One Sullivan Road Holyoke, Massachusetts 01040-2841	(413) 535-4308 (413) 535-4343 Fx mpotishnak@ iso-ne.com
RFC	William Herbsleb Senior Engineer	PJM Interconnection, L.L.C. 955 Jefferson Avenue Valley Forge Corporate Center Norristown, Pennsylvania 19403	(610) 666-8874 (610) 666-2279 Fx herbslhw@pjm.com
RFC	John Swez Manager of Generation Dispatch	Cinergy Corp. 419 East Fourth Street, EA606 Cincinnati, Ohio 45202	(513) 419-5332 john.swez@ cinergy.com
SERC	Larry G. Akens Compliance and System Analysis	Tennessee Valley Authority 1101 Market Street MRBK Chattanooga, Tennessee 37402	(423) 751-8860 lgakens@tva.gov
SPP	Robert C. Rhodes, Jr. Manager, Reliability Coordination	Southwest Power Pool 415 North McKinley Suite 140 Little Rock, Arkansas 72205-3020	(501) 614-3241 (501) 664-9553 Fx rrhodes@spp.org
	Gerald D. Beckerle Senior Transmission Operations Supervisor	Ameren Corp. 1901 Chouteau Avenue St. Louis, Missouri 63103	(314) 554-6413 gbeckerle@ ameren.com
	Randy M. Jones Director, Market Design ERCOT Power Region	Calpine Power Services Company 4100 Underwood Pasadena, Texas 77507	(832) 476-4450 (832) 476-4498 Fx rajones@ calpine.com

	Bart McManus Electrical Engineer	Bonneville Power Administration 5411 NE Highway 99 PO Box 491 Vancouver, Washington 98666	(360) 418-2309 bamcmanus@ bpa.gov
	John Tolo Superintendent, Control Area Operations	Tucson Electric Power Co. 3950 East Irvington Road Tucson, Arizona 85714	(520) 745-7106 (520) 571-4032 Fx jtolo@tep.com
	Raymond L. Vice Consulting Engineer	Southern Company Services, Inc. P.O. Box 2625 Birmingham, Alabama 35202-2625	(205) 257-6209 (205) 257-6663 Fx rlvice@ southernco.com
Staff Coordinator	Thomas J. Vandervort Reliability Assessment & Performance Analysis Coordinator	North American Electric Reliability Council 116-390 Village Boulevard Princeton, New Jersey 08540-5731	(609) 452-8060 (609) 452-9550 Fx tom.vandervort@ nerc.net

Resources Subcommittee

Chairman	Terry Bilke Technical Manager	Midwest ISO, Inc. 701 City Center Drive Carmel, Indiana 46032	(317) 249-5463 (317) 249-5910 Fx tbilke@ midwestiso.org
Vice Chairman & WECC	Donald E. Badley System Operations Manager	Northwest Power Pool 26 S.W. Salmon Street Suite 400 3WTC0402 Portland, Oregon 97204-2991	(503) 464-2805 (503) 464-2819 Fx don@nwpp.org
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RFC	John Swez Manager of Generation Dispatch	Cinergy Corp. 419 East Fourth Street, EA606 Cincinnati, Ohio 45202	(513) 419-5332 john.swez@ cinergy.com
SERC	Larry G. Akens Compliance and System Analysis	Tennessee Valley Authority 1101 Market Street MRBK Chattanooga, Tennessee 37402	(423) 751-8860 lgakens@tva.gov
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	Gerald D. Beckerle Senior Transmission Operations Supervisor	Ameren Corp. 1901 Chouteau Avenue St. Louis, Missouri 63103	(314) 554-6413 gbeckerle@ ameren.com
	Randy M. Jones Director, Market Design ERCOT Power Region	Calpine Power Services Company 4100 Underwood Pasadena, Texas 77507	(832) 476-4450 (832) 476-4498 Fx rajones@ calpine.com

	Bart McManus Electrical Engineer	Bonneville Power Administration 5411 NE Highway 99 PO Box 491 Vancouver, Washington 98666	(360) 418-2309 bamcmanus@ bpa.gov
	John Tolo Superintendent, Control Area Operations	Tucson Electric Power Co. 3950 East Irvington Road Tucson, Arizona 85714	(520) 745-7106 (520) 571-4032 Fx jtolo@tep.com
	Raymond L. Vice Consulting Engineer	Southern Company Services, Inc. P.O. Box 2625 Birmingham, Alabama 35202-2625	(205) 257-6209 (205) 257-6663 Fx rlvice@ southernco.com
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NERC Resources Subcommittee
Survey Contacts

Type:	Date:	Time:	Survey Called:	Due By:
CONTACT	**REGION**	**PHONE**	**CALL**	**REC.**
Paul Kure Bill Herbsleb*	RFC	(330) 580-8006 (610) 666-8874		
Sydney Niemeyer Lane Robinson*	ERCOT	(713) 795-6108 (512) 225-7211		
Don McInnis* Gary Falasca (Inad.) Donna Howard (CPS & AIE)	FRCC	(305) 442-5272 (305) 529-6115 (813) 289-5644		
Alan Oneal* Peter A. Koegel	MRO	(515) 252-6449 (651) 632-8462		
Mike Potishnak*	NPCC	(413) 535-4308		
Larry Akens Teresa Glaze Catherine Sills	SERC	(423) 751-8860 (205) 257-6361 (423) 843-1562		
Larry Akens	TVA SERC	(423) 751-8860		
Robert Rhodes Lisa Carter Katy Onnen	SPP	(501) 614-3241 (501) 614-3346 (501) 614-3353		
Esperanza Cabeza de Vaca (CPS)	WSCC	(801) 582-0353		
John Tolo*	WSCC/AZNMSNV	(520) 745-7106		
Dan Tahija* John Chairez Bill Green	WSCC/CAMX	(916) 351-2115 (916) 608-5775 (916) 351-2116		
Don Badley ChaRee Messerli (Inad.)*	WSCC/NWPP	(503) 464-2805 (503) 464-2809		
Robert Johnson	WSCC/RMPP	(303) 273-4893		
Carlos Martinez	CERTS	(626) 685-2015		
TIME CORRECTIONS: System Coordinator-MAPP Art Storey-NYPP		 (612) 341-4690 (518) 356-6111		

*Primary Contact

May 2006

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

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

Resources Subcommittee Meeting

February 8–10, 2006
Phoenix, Arizona

Minutes

A regular meeting of the North American Electric Reliability Council Resources Subcommittee was held on February 8–10, 2006 in Phoenix, Arizona. The meeting announcement, agenda, and attendance list are attached as **Exhibits A**, **B**, and **C**, respectively. Individual statements and minority opinions are affixed as **Exhibits D** and **E**. (There were none.)

Resources Subcommittee Chairman Terry Bilke presided. The secretary announced that a quorum was present.

Minutes of the Previous Meeting

The Resources Subcommittee approved the October 26–28, 2005 meeting minutes.

Resources Subcommittee Scope and Membership

The secretary announced that the Operating Committee approved the Resources Subcommittee revised scope at its December 2005 meeting. The revised scope can be viewed on the NERC Resources Subcommittee Web site.

Resources Subcommittee Action Item List

The subcommittee reviewed and updated the action item list, which is affixed as **Exhibit F**.

Task Force Reports

Control Criteria Task Force — Chairman Alan Oneal

Real Power Balancing Control Performance Reference Documents Review

The Control Criteria Task Force will review the BAL-001-0, Real Power Balancing Control Performance Standard's reference documents, training documents, operating guidelines, NERC Glossary of Terms, etc. The task force will:

- Evaluate all "shall" statements.
- Incorporate all requirements into the appropriate standard(s) via a standards authorization request.
- Change non-requirement statements to "should" or "may" language.

- Identify and summarize all operating guidelines (including evaluation of "should" statements in reference documents).

Frequency Task Force — Chairman Raymond Vice

Frequency Response and Automatic Generation Control Reference Document Review

The Frequency Task Force will review the BAL-003-0, Frequency Response and Bias, and BAL-005-0, Automatic Generation Control standards' reference documents, training documents, operational guidelines, NERC Glossary of Terms, etc. The task force will:

- Evaluate all "shall" statements.
- Incorporate requirements into the appropriate standard(s) via a standards authorization request.
- Change non-requirement statements to "should" or "may" language.
- Identify and summarize all operating guidelines (including evaluation of "should" statements in reference documents).

Balance Resources and Demand Implementation Plan Assistance

The Resources Subcommittee will be the Balance Resources and Demand standards BAL-007 through BAL-012 custodian when the standards are approved. Supporting the Balance Resources and Demand Standards Drafting Team's implementation plan is critical to the success of these standards.

The Frequency Task Force will interface with the Balance Resources and Demand Standards Drafting Team to ensure the subcommittee assists the drafting team in implementing the standards' requirements and measures. Actions may include:

- Training recommendations for the reliability coordinators and balancing authorities.
- Assist with installing and testing the Balance Resources and Demand required EMS algorithms.
- General assistance to the reliability coordinators and balancing authorities regarding all aspects of the Balance Resources and Demand standards.
- Support and assist the Balance Resources and Demand Standards Drafting Team's implementation plan and timeline.

Balance Resources and Demand Field Trial Frequency Analysis

The Balance Resources and Demand Standards Drafting Team recommends the subcommittee determine how the Balance Resources and Demand field test has impacted the frequency performance of the Eastern Interconnection. Average frequency, standard deviation, and number of significant outliers need to be evaluated. The Balance Resources and Demand Standards Drafting Team expects the new standard will cause more small, short frequency excursions (around the frequency trigger limits but for less than T_v); but decrease the duration of large, long frequency excursions.

The Frequency Task Force will determine how the Balance Resources and Demand field test has impacted the frequency performance of the Eastern Interconnection.

Inadvertent Interchange Task Force — Chairman Don Badley

Time Error Correction and Inadvertent Interchange Reference Document Review

The Inadvertent Interchange Task Force will review the BAL-004-0, Time Error Correction, BAL-006-0, Inadvertent Interchange Standards reference documents, training documents, operational guidelines, NERC Glossary of Terms, etc. The task force will:

- Evaluate all "shall" statements.
- Incorporate requirements into the appropriate standard(s) via a standards authorization request.
- Change non-requirement statements to "should" or "may" language.
- Identify and summarize all operating guidelines (including evaluation of "should" statements in reference documents).

Operating Reserves Task Force — Chairman Larry Akens

Operating Reserves Requirements

Operating Committee Chairman Sam Jones asked the Resources Subcommittee to look at the current reliability standards that address operating reserves to make sure those standards are enforceable and address the needs of the Interconnection.

Larry Akens and the Operating Reserves Task Force will review all "Operating Reserves" in the current reliability standards and all associated "Operating Reserves" definitions in the NERC Glossary of Terms, then forward its evaluation and recommendations to the subcommittee. Chairman Bilke will then report the subcommittee's recommendations or give a status report to the Operating Committee in March 2006.

Disturbance Control Performance Reference Documents Review

The Operating Reserves Task Force will review the BAL-002-0, Disturbance Control Performance standard's reference documents, training documents, operational guidelines, NERC Glossary of Terms, etc. The task force will:

- Evaluate all "shall" statements.
- Incorporate requirements into the appropriate standard(s) via a standards authorization request
- Change non-requirement statements to "should" or "may" language.
- Identify and summarize all operating guidelines (including evaluation of "should" statements in reference documents).

NERC Operating Standards Review

BAL-004-0, Time Error Correction

BAL-005-0, Automatic Generation Control

BAL-006-0, Inadvertent Interchange

The secretary reported that BAL-004-1, BAL-005-1, and BAL-006-1 proposed standard revisions and three individual Standard Authorization Requests (SARs) were submitted to the NERC Standard's Process Manager on January 31, 2006. The draft standards and SARs are on

the Standards Authorization Committee's February 14, 2006 meeting agenda to begin the standards revision process.

Frequency Response SAR

During the January 2006 Standards Authorization Committee meeting, the committee reviewed the progress of the Frequency Response SAR. The committee will solicit industry participants to form a SAR drafting team to draft the SAR in accordance with the NERC Standards Process Manual. The Standards Authorization Committee also instructed the SAR requester, Terry Bilke and the Resources Subcommittee Frequency Task Force to revise the responses to the initial SAR comments and to revise the SAR based on the relevant comments.

Mr. Bilke will review the initial comments again and revise the comment responses and the SAR. He will then forward the comment responses and revised SAR to the subcommittee for additional review. The subcommittee needs to complete this work in a timely manner to include the comment responses and SAR on the March 2006 SAC meeting agenda.

BAL-002-0, Disturbance Control Performance Typographical Errors

Two typographical errors were identified in the BAL-002-0, Disturbance Control Performance standard. The secretary will inform the NERC Standards Process Manager of the errors and determine the process to make the necessary corrections. The two errors are not significant and will not require urgent action.

Resources Subcommittee-Operating Reliability Subcommittee Frequency Discussion

The Resources Subcommittee and the Operating Reliability Subcommittee discussed the Interconnection's frequency profiles, recent frequency excursions, frequency fluctuations, causes of the frequency fluctuations, the reliability implications of the frequency fluctuations, and potential methodologies to identify the balancing authorities and causes of each significant frequency event.

Terry Bilke presented historical data that showed the number of large frequency excursions is decreasing, but the number of small frequency fluctuations is increasing.

The subcommittee will document in a technical paper the recent and historical frequency trends, the root causes behind significant frequency excursions, the reliability implications behind the frequency events, the state of the Interconnections' frequency profiles, and make recommendations to capture, identify the cause, and record the magnitude of each significant frequency excursions.

Projects

Carlos Martinez, Consortium for Electricity Reliability Technology Solutions (CERTS), reported that the Resources Subcommittee has consistently given input during the development phases of the projects listed below. However, the tools that are in production, or will be in production in the near future, need the subcommittee's attention to improve or implement the project applications. The subcommittee reviewed the NERC-CERTS reliability monitoring projects and identified concerns, affixed as **Exhibit G**.

A small subcommittee group will be formed for each project to review the parameters and address concerns. The goal is to recommend project expectations, priorities, uses,

methodologies, specifications, timelines, and anticipated results. The subcommittee volunteers are listed below each project.

ACE-Frequency Application, Project 2000-03

Project Review Team: Leader — Terry Bilke, Raymond Vice, Sydney Niemeyer, Robert Rhodes, Bill Herbsleb, John Tolo, Bart McManus, Tom Vandervort

Develop ACE-Frequency Application Training Project

Project Review Team: Leader — Terry Bilke, Robert Rhodes, Tom Vandervort

AIE Monitoring Application, Project 2000-04

Project Review Team: Leader — Don Badley, Raymond Vice, Bart McManus, John Tolo, Terry Bilke, Don McInnis, Mike Potishnak, Tom Vandervort, Brian Nolan

CPS1 & BAAL Monitoring Application, Project 2001-38

Project Review Team: Leader — Raymond Vice, Doug Hils, Mark Henry, Sydney Niemeyer, John Tolo, Bart McManus, Don Badley, Tom Vandervort

Frequency-Phasor Monitoring Application, Project 2005-X

Project Review Team: Leader — Raymond Vice, Resources Subcommittee Frequency Task Force, Tom Vandervort

Eastern Interconnection Phasor Project

Project Review Team: Leader — Raymond Vice, Resources Subcommittee Frequency Task Force, Tom Vandervort

Inadvertent Interchange Application (SPP Inadvertent Tool Migration), Project 2001-37

Project Review Team: Leader — Don Badley, Inadvertent Interchange Task Force, a representative from Southwest Power Pool (Robert Rhodes will be the point of contact to identify this person), Tom Vandervort

Performance Monitoring

CPS1 Review

The Resources Subcommittee reviewed the monthly and 12-month rolling average CPS1 data for trends and violations. There were no CPS1 violations in October, one violation in November, and one in December 2005. The secretary informed the subcommittee that the NERC compliance department is working closely with the balancing authority that was in CPS1 violation for November and December. There are balancing authorities that have October, November, or December monthly values that are below 100%, but they are not in violation of the 12-month rolling CPS1 average.

Time Error Corrections

The following Interconnection time error corrections from January 1 through December 31, 2005 were reported:

2005	Fast TEC	Slow TEC	Total TEC
Eastern Interconnection	213	0	213
Western Interconnection	35	37	72
ERCOT	41	16	57

Pacific Northwest National Laboratory Testing Facility

Yuri Makarov introduced the Pacific Northwest National Laboratory (PNNL) facilities, staff, research and testing capabilities and its desire to work with NERC and DOE on standard development and proof-of-concept testing.

Don Badley moved that the subcommittee endorse the work that the Pacific Northwest National Laboratory is doing in support of reliability of the North American bulk electric system and encourages the NERC community to work with PNNL in the future. The motion was approved.

Dates and Locations of Future Meetings

1. May 3–5, 2006 Baltimore, MD
2. September 20–22, 2006 Québec City, QU
3. November 15–17, 2006 Fort Lauderdale, FL

Respectfully submitted,

Tom Vandervort

Thomas J. Vandervort
Resources Subcommittee Secretary

Parliamentary Procedures

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

Motions

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

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

Notes on Motions

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

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

Voting

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

Notes on Voting

(Recommendations from DMB, not necessarily Mr. Robert)

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

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

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

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

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

NERC ANTITRUST COMPLIANCE GUIDELINES

I. GENERAL

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

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

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

II. PROHIBITED ACTIVITIES

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

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

Approved by NERC Board of Trustees, June 14, 2002
Technical revisions, May 13, 2005

III. ACTIVITIES THAT ARE PERMITTED

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

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

- Reliability Standards Process Manual
- Organization and Procedures Manual for the NERC Standing Committees
- System Operator Certification Program

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

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

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

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

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

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

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

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

Resources Subcommittee

February 10, 2006 Meeting

Open Action Item List

Action Figure	Subject	Action Item/Assignment	Due Date	Completion Date
Terry Bilke	Frequency Response SAR	011006, The SAC moved that a solicitation be made for self-nominations for the Frequency Response SAR Drafting Team and that the requestor (Terry and the RS Frequency Task Force) revise the comment responses and then revise the SAR to reflect the significant comments. The motion passed. 011006, Terry and FTF to revise the comment responses and to incorporate the significant comments into the Frequency Response SAR. 020806, Terry will re-review the comments, revise the responses and SAR to reflect the significant and relevant comments, and then forward the comment responses and revised SAR to the subcommittee for additional review. 040406, Comment responses from the initial SAR posting and the revised SAR were posted for 30-day comment period (April 4 – May 3, 2006).	040406	040406
Terry Bilke and Resources Subcommittee	Frequency Profile Technical Paper	021006, The Resources Subcommittee will document in a technical paper: • The recent and historical frequency trends • The root causes behind significant frequency excursions and identifiable frequency fluctuations • The reliability implications behind the frequency events • The state of the interconnection's frequency profiles • Make recommendations to capture, identify, and record the magnitude of frequency excursions for each frequency event 050406,	080106	
Resources Subcommittee	RS Reference Document Library	020806, New Action Item - Create a library on the NERC RS web site to capture various frequency, balancing, generation, etc., documents (e.g. technical papers, research papers, training documents, reference documents, task force reports, etc.). RS members to e-mail reference document recommendations for inclusion to Tom Vandervort who will compile the documents for RS review, retention and posting.	Ongoing	
Raymond Vice and FTF	Analysis of how Balance Resources and Demand Field Test has impacted the Eastern Interconnection	021006, The Balance Resources and Demand standard drafting team recommends the Resources Subcommittee determine how the Balance Resources and Demand field test has impacted the frequency performance of the Eastern Interconnection. Average frequency, standard deviation and number of significant outliers needs to be evaluated. The BRD SDT expectation was that small, short frequency excursions (around the frequency trigger limits but for less than T_v) would increase but that the	050406	

Action Figure	Subject	Action Item/Assignment	Due Date	Completion Date
	Frequency Profile	duration of large, long frequency excursions would decrease. The Frequency Task Force will determine how the BRD field test has impacted the frequency performance of the Eastern Interconnection. 050406,		
Don Badley and Review Team	AIE Project	021006, Don Badley and AIE Project review team are to review the AIE project application and then forward comments and recommendations to Carlos Martinez. AIE Project review team members are: Don Badley, Team Leader Raymond Vice Bart McManus John Tolo Terry Bilke Don McInnis Mike Potishnak Tom Vandervort Brian Nolan The review is to be completed by April 1, 2006. 050406,	050406	
Don Badley and IITF	Review BAL-004, BAL-006, Ref Docs, Training Docs, Operations Guidelines, NERC Glossary of Terms, etc.	120805, 1) The Operating Committee (OC) asked the subcommittees to review the use of words such as "shall" in reference documents that implies a requirement. 2) The OC asked the subcommittee to develop operating guidelines that complement the reliability standards for which they are custodians. 021006, Don Badley and Inadvertent Interchange Task Force are to review BAL-004 and BAL-006 reference documents (i.e. training documents, all reference documents, operational guidelines, NERC Glossary of Terms, etc.). Goals are: • Revise reference documents for accuracy, applicability, etc. • Evaluate all "shall" statements. Requirements need to be incorporated into the appropriate standard(s); change non-requirements statements to "should" or "may" language. • Identify and summarize all operational guidelines (including "should" statements in reference documents). Operational guidelines will be brought to the RS and then to the OC. • Review NERC Glossary of Terms definitions of "BAL" terms for accuracy. Reference Documents:	050406	

Action Figure	Subject	Action Item/Assignment	Due Date	Completion Date
		Training Document – Area Interchange Error Survey Training Document Training Document – Inadvertent Interchange Accounting Training Document Others: ? 050406,		
Don Badley	Review Freq Monitoring Guide (Triggers and Actions Guide)	072905, RS reviewed and revised the RS Frequency Monitoring and Response Process (Triggers and Action Guide) for the Western Interconnection. 102705, Don presented it to WECC and it will be addressed by the WECC Performance Criteria WG. 020806, In progress. 050406,	080106	
Don Badley and IITF; Terry Bilke	ATEC in the Eastern Interconnection – Recommendation to the OC	120805, At its December, 2005 meeting, the OC discussed the merits of implementing automatic time error correction in the Eastern Interconnection, and asked the Resources Subcommittee to prepare a recommendation for the committee's March, 2006 meeting. Note: Terry made a presentation to the OC at the Dec, 2005 meeting. This request is related to the BAL-004-1 standard revision and SAR to incorporate automatic time error correction in the Eastern Interconnection. 020806, RS approved the following motion: The RS recommends to the OC that automatic inadvertent interchange payback, similar to the WECC ATEC, be implemented in the Eastern Interconnection after the AIE hourly tool is implemented. 050406, The OC ran out of time to discuss this issue during its March meeting. Terry will present this recommendation to the OC in June, 2006.	050406	
Larry Akens and ORTF	Review BAL-002, Ref Docs, Training Docs, Operations Guidelines, NERC Glossary of Terms, etc.	120805, 1) The Operating Committee (OC) asked the subcommittees to review the use of words such as "shall" in reference documents that implies a requirement. 2) The OC asked the subcommittee to develop operating guidelines that complement the reliability standards for which they are custodians. 021006, Larry Akens and Operating Reserves Task Force are to review BAL-002 reference documents (i.e. training documents, all reference documents, operational guidelines, NERC Glossary of Terms, etc.). Goals are: • Revise reference documents for accuracy, applicability, etc. • Evaluate all "shall" statements. Requirements need to be incorporated into the appropriate standard(s); change non-requirements statements to "should" or "may" language. • Identify and summarize all operational guidelines (including "should" statements in reference documents). Operational guidelines will be brought to the RS and then to the OC.	050406	

Action Figure	Subject	Action Item/Assignment	Due Date	Completion Date
		• Review NERC Glossary of Terms definitions of "BAL" terms for accuracy. Reference Documents: Performance Standard Reference Document (applicable sections) Others: ? 050406,		
Alan Oneal and CCtF	Review BAL-001, Ref Docs, Training Docs, Operations Guidelines, NERC Glossary of Terms, etc.	120805, 1) The Operating Committee (OC) asked the subcommittees to review the use of words such as "shall" in reference documents that implies a requirement. 2) The OC asked the subcommittee to develop operating guidelines that complement the reliability standards for which they are custodians. 021006, Alan Oneal and the Control Criteria Task Force are to review BAL-001 reference documents (i.e. training documents, all reference documents, operational guidelines, NERC Glossary of Terms, etc.). Goals are: • Revise reference documents for accuracy, applicability, etc. • Evaluate all "shall" statements. Requirements need to be incorporated into the appropriate standard(s); change non-requirements statements to "should" or "may" language. • Identify and summarize all operational guidelines (including "should" statements in reference documents). Operational guidelines will be brought to the RS and then to the OC. • Review NERC Glossary of Terms definitions of "BAL" terms for accuracy. Reference Documents: Performance Standard Reference Document Others: ? 050406,	050406	
Larry Akens and ORTF; and Don Badley	Operating Reserves Review	120805, The Operating Committee Chairman Sam Jones asked the RS to look at our current reliability standards that address operating reserves to make sure those standards are enforceable and address the needs of the Interconnections. Note: This action item will require reviewing "BAL" and other reliability standards. 020806, Larry and the ORTF will review all "Operating Reserves" current reliability standards and all associated "Operating Reserves" definitions in the NERC Glossary of Terms, then forward its evaluation and recommendations to the subcommittee. Chairman Bilke will then forward the subcommittee's evaluation and recommendations or status report to the Operating Committee. Larry and ORTF generated a letter from Terry to OC Chairman. 050406, The OC ran out of time to discuss this issue during its March meeting. Terry	050406	

Action Figure	Subject	Action Item/Assignment	Due Date	Completion Date
		will present this recommendation to the OC in June, 2006. Larry, any new thoughts on an Operating Reserves SAR?		
Raymond Vice and Frequency TF	Review BAL-003, BAL-005, Ref Docs, Training Docs, Operations Guidelines, NERC Glossary of Terms, etc.	120805, 1) The Operating Committee (OC) asked the subcommittees to review the use of words such as "shall" in reference documents that implies a requirement. 2) The OC asked the subcommittee to develop operating guidelines that complement the reliability standards for which they are custodians. 021006, Raymond Vice and Frequency Task Force are to review BAL-003 and BAL-005 reference documents (i.e. training documents, all reference documents, operational guidelines, NERC Glossary of Terms, etc.). Goals are: • Revise reference documents for accuracy, applicability, etc. • Evaluate all "shall" statements. Requirements need to be incorporated into the appropriate standard(s); change non-requirements statements to "should" or "may" language. • Identify and summarize all operational guidelines (including "should" statements in reference documents). Operational guidelines will be brought to the RS and then to the OC. • Review NERC Glossary of Terms definitions of "BAL" terms for accuracy. Reference Documents: Performance Standard Reference Document (applicable sections) Frequency Response Characteristics Survey Reference Document Others: ? 050406,	050406	
Raymond Vice and Freq TF	Combustion Turbine Governor Response	050505, The Combustion Turbine Governor Response issue only occurs when gas turbines are operating at maximum output limited by blade temperature as indicated by exhaust gas temperature and only limits response to low frequency deviations. It is not clear what percentage of gas turbines operate in this mode at any given time. In addition, the mass flow of air through the compressor of a gas turbine varies geometrically with frequency (speed of the compressor). This may reduce the ability of the turbine to respond to frequency deviation. The Frequency Task Force will continue to investigate these issues and determine if a NERC Reliability Standard requirement(s) is necessary. 102705, TF proposes changes to the "BAL" standards for RS concurrence and then submittal of a SAR(s) to the NERC standards process manager. See meeting agenda. The problem is that most BA combustion turbine generators operate such that there are no reserves to allow for governor response. There simply is no room for a higher response. Raymond to resurrect his white paper and create combustion turbine bullet points in	050406	

Action Figure	Subject	Action Item/Assignment	Due Date	Completion Date
		order to allow John Undrill to address the RS issues. 020806, Raymond may contact Mr. Undrill to address the RS at the May, 2006 Baltimore RS meeting on combustion turbine governor response. 050406,		
Raymond Vice and Freq TF	Balance Resources and Demand Implementation Plan	021006, The Frequency Task Force needs to interface with the Balance Resources and Demand standard drafting team to ensure the RS assists the drafting team in implementing the standards' requirements and measures. Actions may include: • Training recommendations for the reliability coordinators and balancing authorities. • Assistance with installation of and testing of the Balance Resources and Demand required EMS algorithms. • General assistance to the reliability coordinators and balancing authorities regarding all aspects of the Balance Resources and Demand standards. • Support and Assist the Balance Resources and Demand standards drafting team's implementation plan and timeline. Note: BRD Proposed Implementation plan is included in the May, 2006 agenda. 050406,	050406	
Sydney Niemeyer	Review Freq Monitoring Guide (Triggers and Actions Guide)	072905, RS reviewed and revised the RS Frequency Monitoring and Response Process (Triggers and Action Guide) for the Eastern Interconnection. 102705, Sydney is working with ERCOT staff to address this item. 0504065,	080106	
	NERC-CERTS Project Review			
Terry Bilke	ACE-Frequency Application Review Team	021006, ACE-Frequency Application (NERC Project 2000-03) – A small Resources Subcommittee team will review the issues and address the project parameters. The goal is to recommend expectations, priorities, uses, methodologies, specifications, timelines, and results. Collaboration with ORS, RCWG, NERC Projects, NERC Training Dept, NERC IT, etc. to be initiated as necessary. Project Review Team: Leader-Terry Bilke, Raymond Vice, Sydney Niemeyer, Robert Rhodes, Bill Herbsleb, John Tolo, Bart McManus, Tom Vandervort Group recommendations are to be shared with RS, CERTS and NERC Projects. 050406,	050406	

Action Figure	Subject	Action Item/Assignment	Due Date	Completion Date
Terry Bilke	Develop ACE-Frequency Application Training Documents	021006, ACE-Frequency Application (NERC Project 2000-03) – A small Resources Subcommittee team will review the issues and address the project parameters. The goal is to recommend training lessons content, on-line help application, user friendly training tools. Collaboration with ORS, RCWG, NERC Projects, NERC Training Dept, etc. to be initiated as necessary. Project Review Team: Leader-Terry Bilke, Robert Rhodes, Tom Vandervort Group recommendations are to be shared with RS, CERTS, and NERC Projects. 050406,	050406	
Don Badley	AIE Monitoring Application Review	021006, AIE Monitoring Application (NERC Project 2000-04) – A small Resources Subcommittee team will review the issues and address the project parameters. The goal is to recommend expectations, priorities, uses, methodologies, specifications, timelines, and results. Collaboration with ORS, RCWG, NERC Projects, NERC Training Dept, NERC IT, etc. to be initiated as necessary. Project Review Team: Leader-Don Badley, Raymond Vice, Bart McManus, John Tolo, Terry Bilke, Don McInnis, Mike Potishnak, Tom Vandervort, Brian Nolan Group recommendations are to be shared with RS, CERTS, and NERC Projects. 050406,	050406	
Don Badley	Inadvertent Interchange Application Review	021006, Inadvertent Interchange Application (NERC Project 2001-37) – A small Resources Subcommittee team will review the issues and address the project parameters. The goal is to recommend expectations, priorities, uses, methodologies, specifications, timelines, and results. Collaboration with ORS, RCWG, NERC Projects, NERC Training Dept, NERC IT, etc. to be initiated as necessary. Project Review Team: Leader-Don Badley, Inadvertent Task Force, someone from Southwest Power Pool (Robert Rhodes will be the point of contact to identify who this person will be), Tom Vandervort Group recommendations are to be shared with RS, CERTS, and NERC Projects. 050406,	050406	
Raymond Vice	CPs1 & BAAL Monitoring Application Review	021006, CPS1 & BAAL Monitoring Application (NERC Project 2001-38) – A small Resources Subcommittee team will review the issues and address the project parameters. The goal is to recommend expectations, priorities, uses, methodologies, specifications, timelines, and results. Collaboration with ORS, RCWG, NERC Projects, NERC Training Dept, NERC IT, etc. to be initiated as necessary. Project Review Team: Leader-Raymond Vice, Doug Hils, Mark Henry, Sydney Niemeyer, Don Badley, John Tolo, Bart McManus, Tom Vandervort Group recommendations are to be shared with RS, CERTS, and NERC Projects. 050406,	050408	

Action Figure	Subject	Action Item/Assignment	Due Date	Completion Date
Raymond Vice	Frequency-Phasor Monitoring Application Review	021006, Frequency-Phasor Monitoring Application (NERC Project 2005-06) – A small Resources Subcommittee team will review the issues and address the project parameters. The goal is to recommend expectations, priorities, uses, methodologies, specifications, timelines, and results. Collaboration with ORS, RCWG, NERC Projects, NERC Training Dept, NERC IT, etc. to be initiated as necessary. Project Review Team: Leader-Raymond Vice, Frequency Task Force, Tom Vandervort Group recommendations are to be shared with RS, CERTS, and NERC Projects. 050406,	050406	
Raymond Vice	Eastern Interconnection Phasor Project	021006, ACE-Frequency Application (NERC Project 2000-03) – A small Resources Subcommittee team will review the issues and address the project parameters. The goal is to recommend expectations, priorities, uses, methodologies, specifications, timelines, and results. Collaboration with ORS, RCWG, NERC Projects, NERC Training Dept, NERC IT, etc. to be initiated as necessary. Project Review Team: Leader-Raymond Vice, Frequency Task Force, Tom Vandervort Group recommendations are to be shared with RS, CERTS, and NERC Projects. 050406,	050406	

Item 2. Task Force Reports

Items 2.a–2.d Task Force Reports

Discussion and Action

Some or all of these task forces will meet to discuss their respective issues and concerns on Wednesday, May 3, 2006. The task force chairs will distribute agendas for their respective task force to the subcommittee under separate cover.

Task Force	Task Force Chairman
Control Criteria Task Force	Alan Oneal
Frequency Task Force	Raymond Vice
Inadvertent Interchange Task Force	Don Badley
Operating Reserves Task Force	Larry Akens

Item 3. NERC Reliability Standards

Item 3.a–3.d Enhancements of Reliability Standards

The NERC Operating Committee has assigned the subcommittees as "custodians" of the new reliability standards. It's important to understand that as custodians, each subcommittee will regularly review the reliability standards to make sure they continue to be "safe and effective," and will submit requests for revisions or new standards to the Standards Authorization Committee. The Resources Subcommittee task forces began reviewing each of the "BAL" standards, reference documents, and training documents for completeness, accuracy, and that they correctly reflect the Functional Model functions.

Background

The Resources Subcommittee is reviewing and revising the current "Balancing" standards, BAL-001 through BAL-006, in accordance with the NERC Reliability Standards Process Manual. The review generated the actions noted in the table below. The subcommittee has drafted proposed revisions to standards BAL-004, 005, and 006 and submitted these with standard authorization requests (SARs) to the NERC Standards Process Manager.

Proposed Revisions

"Balancing" Standards	Resources Subcommittee Proposed Significant Revision
BAL-001 Real Power Balancing Control Performance	1. RS to do nothing to this standard at this time. 2. This standard will be superseded by Balance Resources and Demand draft standards (BAL-007 through BAL-012).
BAL-002 Disturbance Control Performance	1. RS to do nothing to this standard at this time. 2. This standard will be superseded by Balance Resources and Demand draft standards (BAL-007 through BAL-012).
BAL-003 Frequency Response and Bias	1. RS to do nothing to this standard at this time. 2. This standard will be superseded by Balance Resources and Demand draft standards (BAL-007 through BAL-012).
BAL-004 Time Error Correction	1. Add clarifying language. 2. Add NAESB v0 Manual Time Error Correction business practices since they affect frequency and are considered a reliability requirement — the methodology to implement a time error correction is to off-set frequency from the normally scheduled 60.00 Hz. Manipulating the Interconnection frequency has serious reliability implications. Every NERC calculation that uses "scheduled frequency" is affected by this standard. 3. Add automatic time error correction to the Eastern Interconnection. WECC automatic time error correction (WATEC) is the model for TEC in the Eastern

"Balancing" Standards	Resources Subcommittee Proposed Significant Revision
	Interconnection. WECC will to continue using the WATEC procedure. The automatic time error correction process adjusts the "Control ACE" to pay back inadvertent interchange, thus having reliability implications. 4. BAL-004-1 draft standard and SAR have been submitted to NERC Standards Process. 5. The SAR drafting team will work cooperatively with NAESB to revise this standard to assure it is developed in harmony with the NAESB business practices standard(s).
BAL-005 Automatic Generation Control	1. Add clarifying language. 2. Add NAESB v0 ACE Equation Special Cases business practices since they affect frequency and are considered reliability requirements — these special cases are pseudo ties and dynamic schedules that affect the ACE equation and have reliability implications. a. Add Supplemental Regulation Service requirements. b. Add Overlap Regulation Service requirements. c. Add Pseudo Ties requirements. d. Add Dynamic Schedule requirements. 3. BAL-005-1 draft standard and SAR have been submitted to NERC Standards Process. 4. The SAR drafting team will work cooperatively with NAESB to revise this standard to assure it is developed in harmony with the NAESB business practices standard(s).
BAL-006 Inadvertent Interchange	1. Add clarifying language. 2. Add NAESB v0 Inadvertent Interchange Payback business practices since they affect frequency and are considered reliability requirements. The unilateral inadvertent interchange payback control offset is based on the ACE equation and is limited to the balancing authority's L_{10} limit. As long as unilateral payback is based on the ACE equation (and includes a limiting factor of ACE – L_{10}) it reflects reliability implications. 3. Add inadvertent interchange calculations, requirements, and measures. 4. Add inadvertent interchange dispute resolution requirements. 5. Evaluate and incorporate appropriate operating policy waivers into the proposed standard revision. 6. Add MISO and SPP "scheduling agent" Regional

"Balancing" Standards	Resources Subcommittee Proposed Significant Revision
	Difference. 7. BAL-006-1 draft standard and SAR have been submitted to NERC Standards Process. 8. The SAR drafting team will work cooperatively with NAESB to revise this standard to assure it is developed in harmony with the NAESB business practices standard(s).

The secretary will report to the subcommittee on the coordinated effort by the SAR drafting team along with NAESB to assure BAL-004 through BAL-006 are revised in harmony with the NAESB business practices standards.

Reference Documents Discussion and Action

The subcommittee is reviewing the associated "BAL" reference and training documents for completeness, accuracy, relevancy to the reliability standards, and to ensure Functional Model functions are accurately reflected. The Operating Committee also asked the subcommittees to review the use of words such as "shall" in these documents that imply a requirement.

a. Performance Standards Reference Document — Alan Oneal
b. Area Interchange Error Survey Training Document — Don Badley
c. Frequency Response Characteristic Survey — Raymond Vice
d. Inadvertent Interchange Accounting Training Document — Don Badley

Attachments

1. Performance Standards Reference Document
2. Area Interchange Error Survey Training Document
3. Frequency Response Characteristic Survey
4. Inadvertent Interchange Accounting Training Document

Item 3.e Balance Resources and Demand Standard Update — Raymond Vice

Balance Resources and Demand Phase II Field-Test and Draft Standards

Mr. Vice will provide a status report on the field test and time-line schedule for balloting and implementing the standards. The Balance Resources and Demand (BRD) draft standard Phase II field test began July 6, 2005 and will continue until the standards are balloted, and if approved, then until the standards are implemented. The field test is a real-time, proof-of-concept test of the proposed BRD Standard Balancing Authority ACE Limit (BAAL), the Frequency Trigger Limits (FTL), the Frequency Abnormal Limits (FAL), and the Frequency Relay Limits (FRL).

The Resources Subcommittee will be the BAL-007 through BAL-011 implementation subcommittee and will be the custodian of these standards when they are approved. The subcommittee will consider the Balance Resources and Demand standards' implementation details and strategies that are necessary to execute the standard when they are approved. The subcommittee's efforts are critical to the success of these standards. These include:

- Resources Subcommittee Balance Resources and Demand standards training recommendations for the reliability coordinators and balancing authorities
- Resources Subcommittee assistance with installation of and testing of the Balance Resources and Demand required EMS algorithms and visual displays

- General assistance to the reliability coordinators and the balancing authorities regarding all aspects of the Balance Resources and Demand standards
- Assistance of the Balance Resources and Demand standard drafting team's implementation plan and timeline

Attachments

Balance Resources and Demand Implementation Plan

Item 3.f Frequency Response SAR — Terry Bilke, Tom Vandervort

The Frequency Response SAR is posted for a 30-day comment period (April 4–May 3, 2006). The Resources Subcommittee sponsored this SAR and requests that you review the SAR and submit comments during the comment period.

Training Document Subsections

A. Area Control Error
B. Performance Standard
C. Calculation of Compliance
D. Survey Procedures

This document provides the NERC Control Performance Compliance Survey coordinator with specific instructions on calculating the control performance of the control area and instructions to complete the survey forms contained in the document as CPS Form 1 and 2 and Form DCS.

The control area is required to continuously monitor its control performance and report its compliance results at the end of each month. This training document provides an explanation of the reporting requirements for the NERC Control Performance Standard.

A. Area Control Error

[Appendix 1A — The Area Control Error Equation]

The control area's Area Control Error (ACE) is the basis for the calculation of control parameters used to evaluate control performance. One part of the NERC Control Performance Standard (CPS) is defined by the control parameter:

$$\left[\left(\frac{ACE_i}{-10B_i}\right)_1 * \Delta F_1\right]$$

wherein the subscript 1 indicates one-minute clock averages. This parameter is used to determine a control area's control performance with respect to the control area's impact on system frequency. The values of ACE to be used throughout the calculation of the control parameter shall reflect its actual value and exclude short excursions due to transient telemetering problems or other influences such as control algorithm actions. Erroneous readings such as "spikes" due to telemetering error or other false influences should be excluded from the calculations. However, the computations should include ALL of the non-erroneous intervals (i.e., do not exclude intervals that contains disturbance conditions). This ACE is defined as net actual interchange less net scheduled interchange less frequency bias contribution and meter error. It does not include offsets (e.g., unilateral inadvertent payback, WSCC's automatic time error correction, etc.).

B. Performance Standard

[Appendix lA — The Area Control Error Equation]

The CPS is composed of two measures. One measure is a statistical measure of ACE variability and its relationship to frequency error. The second measure is a statistical measure designed to limit unacceptably large net unscheduled power flows. These two measures define the NERC Control Performance Standard. ***The NERC Control Performance Standard is the measure against which all control areas will be evaluated***.

The first measure of the CPS survey provides a measure of the control area's performance. This control performance measure is defined in Section B.1.1.1. The measure is intended to provide the control area

with a frequency-sensitive evaluation of how well the respective area met its demand requirements. The measure is not designed to be a visual indicator that an operator would use to control system generation. Nor is this measure designed to address the issue of unscheduled power flows, or minimization of inadvertent interchange.

The second measure of the CPS survey is designed to bound ACE ten-minute averages and provides an oversight function to limit excessive unscheduled power flows that could result from large ACEs. The measure to limit the magnitude of ACE is described in Section B.1.1.2.

These measurements of control performance apply to all conditions (i.e., both normal and disturbance conditions). The CPS is supplemented by a Disturbance Control Standard that establishes bounds for system recovery. The following discussion expands the definitions of the criteria found in Operating **Policy l.E. — Control Performance** and defines the respective measurements and associated criteria.

1. Continuous Monitoring Requirements. The NERC Control Performance Standard defines a minimum acceptable control performance that a control area is expected to maintain over all operating conditions.

C. **Parameters.** The Control Performance Standard imposes two requirements.

D. **CPS1.** Over a given period, the average of the clock-minute averages of a control area's [ACE divided by ten times its bias] times the corresponding clock-minute averages of the Interconnection's frequency error shall be less than the constant on the right-hand side of the following inequality:

$$AVG_{Period}\left[\left(\frac{ACE_i}{-10B_i}\right)_1 * \Delta F_1\right] \le \in_1^2 \ or \ \frac{AVG_{Period}\left[\left(\frac{ACE_i}{-10B_i}\right)_1 * \Delta F_1\right]}{\in_1^2} \le 1$$

where: ACE_i is the clock-minute average of ACE (as ACE is defined in Section A),

B_i is the frequency bias of the control area. For those areas with variable bias, an area should accumulate ACE/(–10B) through the AGC cycles of a minute, and save the averaged value at the end of the minute as the clock-minute value of $ACE_i/(-10B_i)$,

$\in_1$ is a constant derived from the targeted frequency bound. It is the targeted RMS of one-minute average frequency error from a schedule based on frequency performance over a given year. The bound is the same for every control area within an Interconnection,

ΔF is the clock-minute average of frequency error from schedule, $\Delta F = F_a - F_s$, where F_a is the actual (measured) frequency and F_s is scheduled frequency for the Interconnection,

I is representative of the control area,
Period is defined as:
a) one year for control area evaluation
b) one month for Resources Subcommittee review

E. **CPS2.** Over a clock ten-minute period, the ten-minute averages of a control area's ACE shall be less than the constant on the right-hand side of the following inequality:

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

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

$\in_{10}$ is a constant derived from the targeted frequency bound. It is the targeted RMS of ten-minute average frequency error from schedule based on frequency performance over a given year. The bound, $\in_{10}$, is the same for every control area within an Interconnection,

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

B_i is the frequency bias of the control area, and

B_s is the sum of the frequency bias settings of the control areas in the respective Interconnection; for systems with variable bias, this is equal to the sum of the minimum frequency bias settings.

For those systems with variable bias, CPS2 becomes:

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

where:

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

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

F. **Targeted Frequency Bounds.** The Targeted Frequency Bounds, $\in_1$and $\in_{10}$, are based on historic measured frequency error. These bounds embody the targeted frequency characteristics used for developing the Control Performance Standard. Each Interconnection will be assigned its own frequency bounds.

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

G. NERC Resources Subcommittee (RS) defines a desired frequency profile. This profile will be derived from the frequency experienced over a RS-selected one-year period.

H. NERC RS collects the frequency data from designated providers within each Interconnection. The frequency bounds are the RMS of the one-and ten-clock-minute averages of the frequency error from schedule. These values are derived from data samples over a given year. NERC RS calculates the targeted

frequency bounds, $_1$ and L_{10}, to recognize the desired performance of frequency for each Interconnection.

I. **Compliance for Control Areas.** A control area that does not comply with CPS is not providing its required regulation service.

J. If a control area does not comply with the CPS, the control area is not permitted to provide regulation or other services related to control performance for any other control area(s) or other entities. Those services shall be determined by the NERC RS.

K. A control area failing to comply shall take immediate corrective action and achieve compliance within three months. If necessary, a control area shall buy sufficient supplemental regulation to achieve compliance.

L. **Compliance for Control Areas Providing Regulation.** A control area is not permitted to provide regulation or other services related to control performance (as determined by the NERC Resources Subcommittee) for (an)other control area(s) or other entities external to that control area, if the former control area does not comply with the CPS.

M. **Compliance for Control Areas Participating in Supplemental Regulation.** A control area providing or receiving supplemental regulation, either through dynamic schedules or pseudo-ties, will continue to be evaluated on the characteristics of its own area control error with the supplemental regulation service included. The $\left[\left(\frac{ACE_i}{-10B_i}\right)_1 * \Delta F_1\right]$ for each of the affected control areas will not change.

N. **Compliance for Control Areas Participating in Overlap Regulation.**

O. **Control Areas Providing Overlap Regulation.** A control area *providing* overlap regulation shall continue to be evaluated on the characteristics of the combined areas' ACE. The provider control area must calculate and use the combined limit using the sum of its own frequency bias setting, B_i, and the frequency bias setting, B_j, of the control area for which it is providing the overlap regulation.

P. **Control Areas Receiving Overlap Regulation.** A control area *receiving* overlap regulation service shall not have its control performance evaluated.

2. Disturbance Conditions. During a disturbance, controls cannot usually maintain ACE within the criteria for normal load variation. However, an area is expected to activate operating reserve to recover ACE within fifteen minutes. This requires that a disturbance condition be defined. For purposes of disturbance control compliance, REPORTABLE DISTURBANCES are contingencies that are greater than or equal to 80% of the MOST SEVERE SINGLE CONTINGENCY loss. Regions may optionally reduce the 80% threshold, provided that normal operating characteristics are not being considered or misrepresented as contingencies. Normal operating characteristics are excluded because DCS only measures the recovery from sudden, unanticipated losses of supply-side resources.

Normal load and generation excursions (e.g., pumped storage hydro, arc furnace, rolling steel mill, etc.) that influence ACE are not reportable disturbance conditions.

Q. **Control Area.** A CONTROL AREA shall return its ACE either to zero or to its pre-disturbance ACE level within fifteen minutes following a disturbance. A control area may, at its discretion, measure its compliance based on the ACE measured fifteen

minutes after the disturbance, or based on the maximum ACE recovery measured within the fifteen minutes following the disturbance.

R. **Reserve Sharing Group.** The disturbance control compliance for a control area within a Reserve Sharing Group is based on the compliance of the Reserve Sharing Group (according to the compliance method chosen in section 3.2.2. of Policy 1A). A reserve sharing group area may, at its discretion, measure this recovery based on the combined ACE measured fifteen minutes after the disturbance, or on the maximum combined ACE recovery measured within the fifteen minutes following the disturbance.

C. Calculation of Compliance

1. Control Compliance Rating. Control area compliance will be determined by examining both CPS parameters. One parameter (CPS1) measures control impact on frequency. This parameter is calculated from a MW-Hz error value computed over a sliding 12-month period. The second parameter (CPS2) is a function of the ten-minute ACE magnitudes over a one-month period. Compliance to the two measures is outlined below:

Control Compliance Rating = Pass if CPS1 ≥ 100% *and* CPS2 ≥ 90%

Control Compliance Rating = Fail if CPS1 < 100% *or* CPS2 < 90%

S. **Control Performance Standard 1 (CPS1)**. The frequency-related parameter, CPS1, converts a compliance ratio to a compliance percentage as follows:

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

The frequency-related Compliance Factor, CF, is a ratio of all one-minute compliance parameters accumulated over 12 months divided by the Target Frequency Bound:

$$CF = \frac{CF_{12-\text{month}}}{(\in_1)^2}$$

where: $CF_{12\text{-month}}$ is defined in Section C.1.1.1,

$\in_1$ is defined in Section B.1.1.1.

Note that compliance percentages can be calculated for other bases (month, day, shift hours, etc.) by simply replacing $CF_{12\text{-month}}$ in the above formula with the appropriate CF value.

T. **$CF_{12\text{-month}}$ Calculation.** The rating index is derived from 12 months of data. The basic unit of data comes from one-minute averages of ACE, frequency error and frequency bias settings.

U. **Clock-minute average.** A clock-minute average is the average of the reporting control area's valid measured variable (i.e., for ACE and for frequency error, as well as for the control area's frequency bias, as defined in section B.1.1.1.) for each sampling cycle during a given clock-minute.

$$\left(\frac{ACE}{-10B}\right)_{\text{clock-minute}} = \frac{\left(\frac{\sum ACE_{\text{sampling cycles in clock-minute}}}{n_{\text{sampling cycles in clock-minute}}}\right)}{\text{-10B}}$$

$$\Delta F_{\text{clock-minute}} = \frac{\sum \Delta F_{\text{sampling cycles in clock-minute}}}{n_{\text{sampling cycles in clock-minute}}}$$

The control area's clock-minute Compliance Factor (CF) becomes:

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

V. **Hourly Average.** Normally, sixty (60) clock-minute averages of the reporting area's ACE and of the respective Interconnection's frequency error will be used to compute the respective Hourly Average Compliance parameter.

$$CF_{\text{clock-hour}} = \frac{\sum CF_{\text{clock-minute}}}{n_{\text{clock-minute samples in hour}}}$$

W. **Accumulated Averages.** The reporting entity can recalculate and store each of the respective clock-hour averages ($CF_{\text{clock-hour average-month}}$) as well as the respective number of samples for each of the twenty-four (24) hours (one for each clock-hour, i.e., HE 0100, HE 0200, ..., HE 2400).

$$\text{CF}_{\text{clock-hour average-month}} = \frac{\sum_{\text{days-in-month}} [(\text{CF}_{\text{clock-hour}})(n_{\text{one-minute samples in clock-hour}})]}{\sum_{\text{days-in month}} [n_{\text{one-minute samples in clock-hour}}]}$$

$$\text{CF}_{\text{month}} = \frac{\sum_{\text{hours-in-day}} [(\text{CF}_{\text{clock-hour average-month}})(n_{\text{one-minute samples in clock-hour averages}})]}{\sum_{\text{hours-in day}} [n_{\text{one-minute samples in clock-hour averages}}]}$$

The 12-month Compliance Factor becomes:

$$\text{CF}_{\text{12-month}} = \frac{\sum_{\text{i=1}}^{12} (CF_{\text{month-i}})(n_{(\text{one-minute samples in month})-\text{i}})]}{\sum_{\text{i=1}}^{12} [n_{(\text{one-minute samples in month})\text{-i}}]}$$

Note that if data was not collected for all days of the month (or hours in day, or minutes in hour, etc.), then the summations in the above formulas should be for "sample" days (or hours, minutes, etc.).

1.1.2. **Sustained Interruption in the Recording of ACE and Frequency Deviation.** In order to ensure that the average ACE and Frequency Deviation calculated for any one-minute interval is representative of that one-minute interval, it is

necessary that at least 50% of both ACE and Frequency Deviation samples during that one-minute interval be present. Should a sustained interruption in the recording of ACE or Frequency Deviation due to loss of telemetering or computer unavailability result in a one-minute interval not containing at least 50% of samples of both ACE and Frequency Deviation, that one-minute interval shall be excluded from the calculation of CPS1.

At the end of the month, each of the respective hourly averages are used to calculate that month's Compliance Factor as follows:

X. **Control Performance Standard 2 (CPS2)**. The second parameter in the Control Performance Rating relates to a bound on the ten-minute average of ACE. A compliance percentage is calculated as follows:

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

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

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

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

Each area shall report the total number of Violations and Unavailable Periods for the month. L_{10} is defined in Section B.1.1.2.

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

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

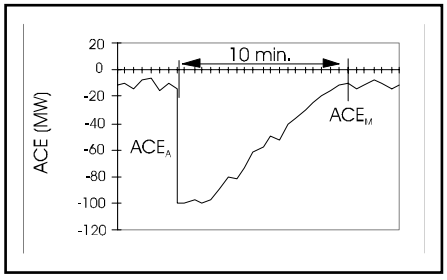
An incident of non-compliance is recorded for any ten-minute period where the absolute value of average ACE is greater than L_{10}.

Z. **Condition that Impacts the Calculation of Total Periods$_{month}$ and Violations$_{month}$.** A condition may arise which may impact the normal calculation of Total Periods$_{month}$ and Violations$_{month}$. This condition is a sustained interruption in the recording of ACE.

AA. **Interruption in the Recording of ACE**. In order to ensure that the average ACE calculated for any ten-minute interval is representative of that ten-minute interval, it is necessary that at least half the ACE data samples are present for that interval. Should half or more of the ACE data be unavailable due to loss of telemetering or computer unavailability, that ten-minute interval is omitted from the calculation of CPS2.

BB. **Data Reporting.** The control area is responsible for submitting the Control Performance Standard survey each month. In addition (for post-reporting analysis by the Regional Resources Subcommittee representative), the control area is responsible for retaining sufficient CF and other pertinent data (see Appendix 1H).

2. Disturbance Control Standard. A control area or reserve sharing group must calculate and report compliance with the Disturbance Control Standard for all disturbances greater than or equal to 80% of the magnitude of the control area's or of the reserve sharing group's most severe single contingency loss. Regional Reliability Councils may, at their discretion, require a lower reporting threshold. Disturbance Control Standard is measured as the percentage recovery, R_i

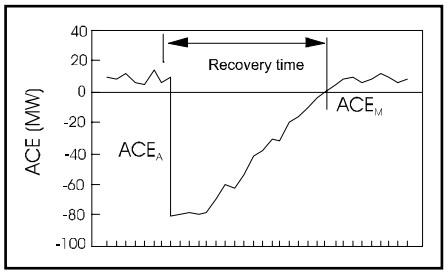


For loss of generation:

if $ACE_A < 0$

then

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



if $ACE_A >= 0$

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

where: MW_{LOSS} is the MW size of the disturbance as measured at the beginning of the loss,

ACE_A is the pre-disturbance ACE,

ACE_M is the maximum algebraic value of ACE measured within the fifteen minutes following the disturbance event. A control area or reserve sharing group may, at their discretion, set $ACE_M = ACE_{15\ min}$, and

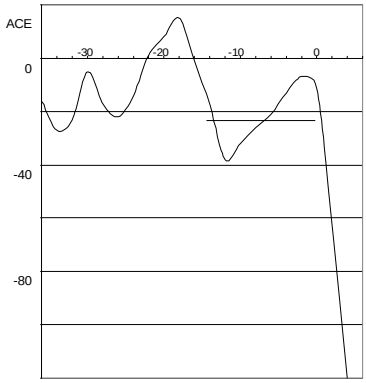
ACE_m is the minimum algebraic value of ACE measured within the fifteen minutes following the disturbance event. A control area or reserve sharing group may, at their discretion, set $ACE_m = ACE_{15\ min}$.

CC. Determination of MW_{LOSS}.

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

DD. Determination of ACE_A.

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



EE. **Determination of ACE_M or ACE_m.**

ACE_M is the maximum value of ACE measured within fifteen minutes following a given disturbance. At the discretion of the control area or of the Reserve Sharing Group, compliance may be based on the ACE measured fifteen minutes following the disturbance, i.e., $ACE_M = ACE_{15\ min}$.

ACE_m is the minimum value of ACE measured within fifteen minutes following a given disturbance. At the discretion of the control area or of the Reserve Sharing Group, compliance may be based on the ACE measured fifteen minutes following the disturbance, i.e., $ACE_m = ACE_{15\ min}$

3. Examples.

Below is an example of the calculations required for CPS1 monitoring and compliance. The example starts with the first hour of the first day of a month through to the end of the month. Let's assume this area has a bias, B = –60MW/0.1 Hz.

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

HE 0100:		***Minute 1***	***Minute 2***	***...***	***Minute 60***		
ACE/-10B	(Hz)	-20/-10(-60)	10/-10(-60)	...	40/-10(-60)		
ΔF	(Hz)	0.005	-0.005	...	0.005	***Sum***	***$CF_{clock\text{-}hour} = \Sigma(CF)/n$***
$CF_{clock\text{-}minute}$ =	(Hz^2)	-0.000167	-0.000083	...	-0.000333	0.00525	0.000088
(ACE/-10B) x ΔF	(mHz^2)	-166.667	-83.333		333.333	5250.0	87.5000
n (# of samples)		1	1		1	60	

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

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

A rolling $CF_{12\text{-month}}$ can be calculated using the CF_{month} values.

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

Assuming this area has an ε_1 of 10 MHz, then its CPS1 compliance percentage would be calculated as follows (as described in section C.1.1):

$$CF = CF_{12\text{-month}} / (\varepsilon_1)^2$$

$$= 91.3 / (10)^2$$

= 91.3 / 100

= .913

CPS1 = (2 – CF) x 100

= (2 - .913) x 100

= (1.087) x 100

= 108.7% which is a "passing" grade (CPS1 must be greater than or equal to 100)

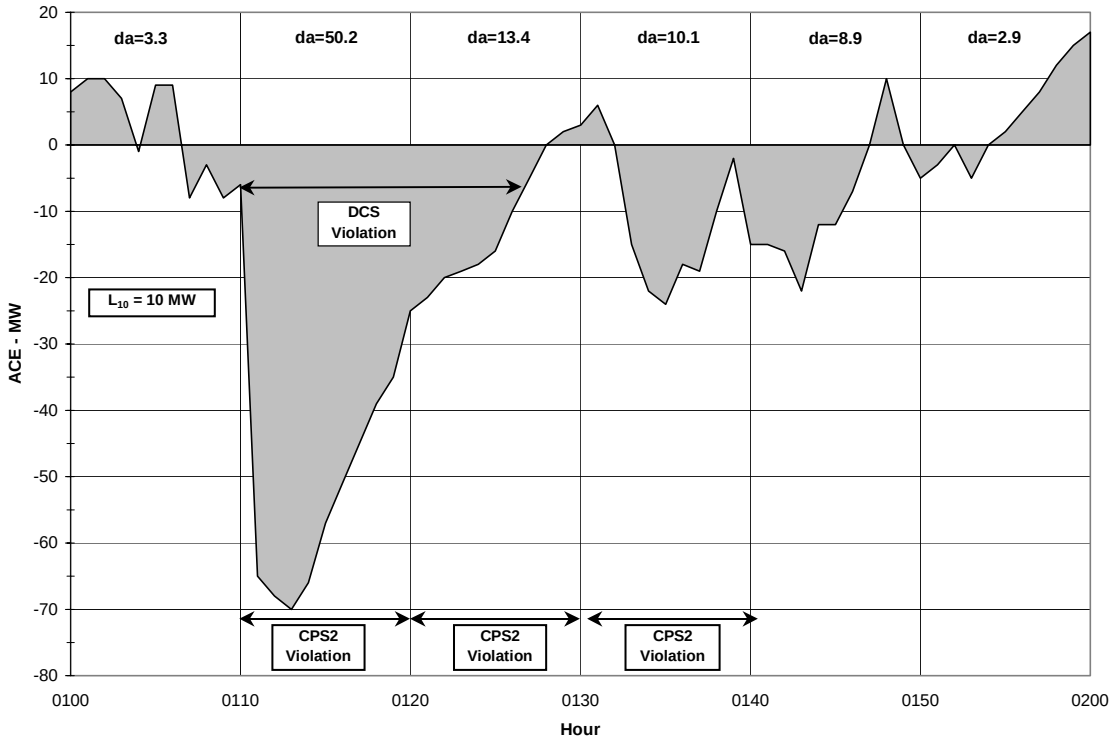


Figure 1 –- CPS2-L_{10} Compliance & Disturbance Control Standard, 2 Disturbance Examples

Figure 1 demonstrates various examples of L_{10} compliance (CPS2 Standard) and a disturbance condition (Disturbance Control Standard). Note that Figure 1 is separated into six distinct, cyclic ten-minute periods. The absolute value of the algebraic mean of the ACE during each period, referred to as d_a, is compared to L_{10} (10 MW for this system) to determine a violation. Note that the fourth interval (0130 – 0140) has recorded a violation because the absolute value of the algebraic mean of 10.1 MW exceeds the L_{10} of 10 MW. Since disturbance conditions are included in the CPS2 calculation, violations are also recorded for the second and third intervals (0110–0120 & 0120–0130).

Note the pattern of the disturbance condition, which began at 0110. During this disturbance, the Disturbance Control Standard was violated because ACE was not restored to its pre-contingency level until 0127 (a 17-minute interval which violates the Disturbance Control Standard).

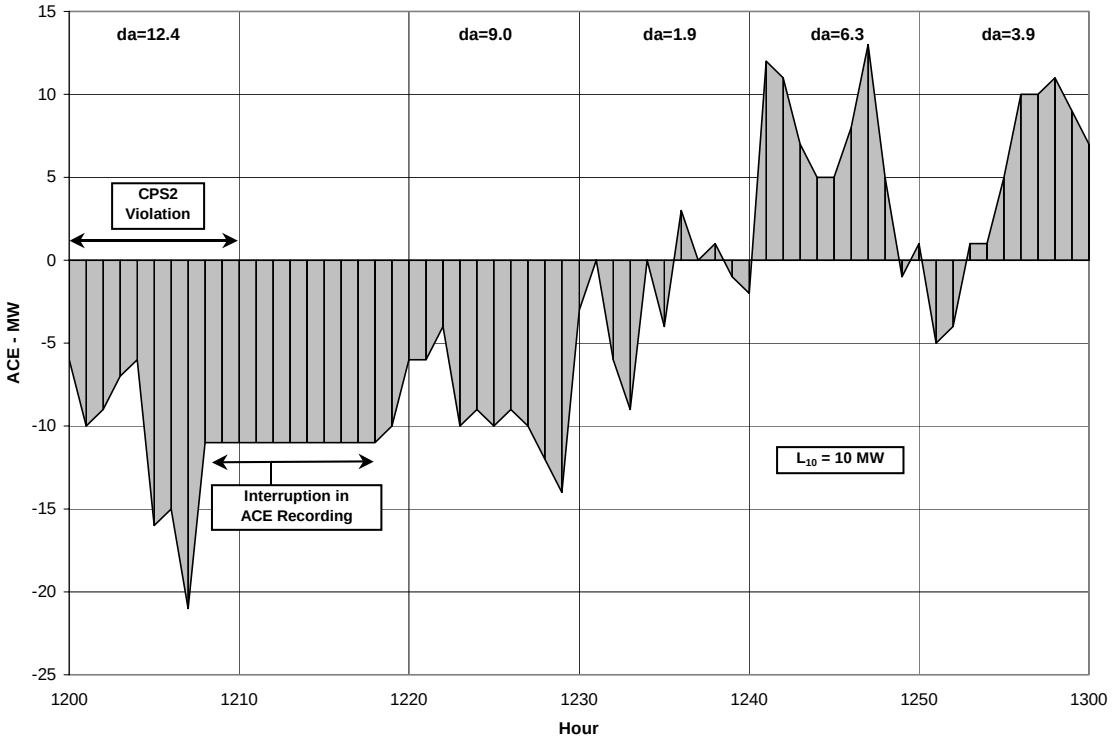


Figure 2 – L_{10} Compliance Examples

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

D. Survey Procedures

Performance Standard surveys will be conducted monthly to analyze each control area's level of compliance with the CPS1 and CPS2 Control Performance Standards. The surveys provide a relative measure of each control area's performance.

1. Issuance of Survey. Monthly averages are to be completed after the end of each month.

FF. Each control area shall return one completed copy of CPS Form 1, "NERC Control Performance Standard Survey — All Interconnections" to the Resources Subcommittee member representing the Region by the tenth working day of the month following the month reported.

2. Instructions for Control Area Survey. Using data derived from digital processing of the ACE signal, a representative from each control area will complete CPS Form 1, "NERC Control Performance Standard Survey — All Interconnections."

GG. Hourly Table.

CPS1 Report the clock-hour average compliance factor (CF) for each of the 24-hour periods and the total number of samples in each hourly average (as described in section C.1.1.1.3).

CPS2 For each of the 24 hourly periods of a day, report the monthly total number of CPS2 violations and the number of unavailable ten-minute periods. For example, if there was one violation for hour ending 0100 every day of a 31-day month, a 31 would be entered for the 0100 hourly period.

HH. CPS1, CPS2 Standard Summary.

CPS1	CF_{month}	Report the monthly compliance factor and enter in this cell using the formulas and procedures described in Sections C.1.1.1.3.
	$CF_{12\text{-}month}$	Report the rolling 12-month compliance factor and enter in this cell using the formulas and procedures described in Sections C.1.1.1.
	CPS1 (%)	Calculate the CPS1 percentage compliance and enter in this cell using the formulas and procedures described in Sections C.1.1.
CPS2	TOTAL	Sum the clock-hour average compliance factors, the number of samples, the number of violations, and unavailable ten-minute intervals recorded on the hourly tables and enter the sums on this row for each column.
	CPS2 (%)	Calculate the CPS2 percentage compliance and enter in this row using the formulas and procedures described in Sections C.1.2.

3. Instructions for Regional and NERC Surveys. From a review of the control areas' surveys, each Regional Survey Coordinator or RS member will complete CPS Form 2, "NERC Control Performance Standard — Regional Summary."

II. Review CPS Form 1 data received from each control area in the Region for uniformity, completeness, and compliance to the instructions. Iterate with control area survey coordinators where necessary.

JJ. Transfer the data from each Form to the appropriate columns on CPS Form 2. Review the comments submitted and, if significant, identify them with the appropriate control areas.

KK. Forward a copy of the completed CPS Form 1 and 2 to the NERC staff.

LL. The NERC staff will combine the Regional reports into a single summary report and send one copy to each RS member.

MM. Each RS member is responsible for sending the summary report to the utilities in the Region.

4. Disturbance Control Standard.

Each Control Area or Reserve Sharing Group shall report its Disturbance Control Standard compliance quarterly. The completed Disturbance Control Standard survey shall be supplied to NERC by the 20th day following the end of the respective quarter. Where reserve sharing groups exist, the Regional Reliability Council shall decide either to report these on a control area basis or on a reserve sharing group basis. If a reserve sharing group has dynamic membership, then it will be required for the Region to convert the disturbance reporting for the group to a control area basis before reporting to NERC. If a control area basis is selected, each control area reports the reserve sharing group's performance only for disturbances occurring in their area.

NN. **Reportable Disturbance.** The definition of a reportable disturbance shall be provided by the respective Regional Reliability Councils. The definition shall include events that cause an ACE change greater than or equal to 80% of a control area's or reserve sharing group's most severe contingency. The definition of a reportable disturbance must be specified in the operating Policy adopted by each Regional Reliability Council. This definition may not be retroactively adjusted in response to observed performance.

OO. **Most Severe Single Contingency.** A control area's most severe single contingency is defined as the magnitude of the single most credible event that would cause the greatest change in the control area's ACE or as defined by the respective Regional Council.

PP. **Excludable Disturbances and Average Percent Recovery.** The control areas or reserve sharing group shall report both the number of reportable disturbances that occur in the given quarter, and the average percent recovery for that quarter. The control area must also report the excludable disturbances that occurred in the quarter and the average percent recovery for those excluded events.

QQ. **Excludable Disturbance.** An excludable disturbance is a disturbance whose magnitude was greater than the magnitude of the control area's most severe single contingency.

RR. **Average Percent Recovery.** The average percent recovery is the arithmetic average of all the calculated R_i's from reportable disturbances during the given quarter. Average percent recovery is similarly calculated for excludable disturbances. (See Section C.2 for calculation of R_i.

SS. **Contingency Reserve Adjustment Factor.** The quarterly Contingency Reserve Adjustment factor shall include only those reportable disturbances with magnitudes less than or equal to the magnitude of the respective control area's most severe contingency.

TT. **Contingency Reserve Adjustment factor.** The factor is defined as follows:

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

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

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

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

i = reportable disturbances.

R_i is defined in section C.2.

UU. **Calculation Precision.** The Adjustment Factor shall be rounded off to two decimal places.

VV. **Exemptions.** Requests for exemptions for single events that cause multiple reportable disturbances (e.g. hurricanes, earthquakes, islanding, etc.) shall be submitted to the NERC Director of Compliance. Until the exemption is approved or denied, the control area or reserve sharing group shall consider the request denied.

WW. **Contingency Reserve Adjustment Period.** Control areas shall revise their respective Contingency Reserve Requirement by their computed Contingency Reserve Adjustment factor. The adjustments will be effective starting one month following the end of the reported quarter and remains in effect for three months.

XX. **Instructions for Disturbance Control Standard Survey.** Each control area or Reserve Sharing Group shall report its Disturbance Control Standard compliance quarterly on Form DCS "NERC Disturbance Control Standard Survey."

YY. Mail a copy of the completed Form DCS to the NERC staff.

ZZ. The NERC staff will combine the Regional reports into a single summary report and send one copy to each Subcommittee member.

AAA. Each Subcommittee member is responsible for sending the summary report to the utilities in the Region.

D. Survey Procedures

NERC Control Performance Standard Survey All Interconnections **CPS Form 1**								
Region			**Control Area**					
L_{10} -			**Month -**		**Year -**		**ε –**	
H.E. Central Time	**CPS1**				**CPS2**			
	CF	%	Number of Samples		Violations		Unavailable Periods	
0100								
0200								
0300								
0400								
0500								
0600								
0700								
0800								
0900								
1000								
1100								
1200								
1300								
1400								
1500								
1600								
1700								
1800								
1900								
2000								
2100								
2200								
2300								
2400								
CPS1 Month -			0	CPS2 Month -	0		0	

Notes:

NERC Control Performance Standard Survey – Regional Summary CPS Form 2				
Region:	**Month:**	**Year:**	**Date:**	
Control Area:			**Control Performance Compliance**	
			CPS1 Monthly	**CPS2 Monthly**
ID #	**Name**		**Compliance %**	**Compliance %**

NERC Disturbance Control Standard Report

Quarter:		Disturbances Not Greater than the Most Severe Single Contingency Loss		Disturbances Greater than the Most Severe Single Contingency Loss[3]		This Quarter's CRAF[4]	Criteria for Determining Reportable Disturbances This Report	Criteria for Determining Reportable Disturbances Next Report
Year:								
Region:								
Control Area/RSG[1]:		Number	APR[2] (a)	Number	APR			

[1] When reporting as a Reserve Sharing Group (RSG), submit data for the entire group only and list the Control Areas comprising the RSG.
[2] APR indicates the Average Percent Recovery.
[3] Not a performance measure. For informational purposes only.
[4] [200-(a)], please round to the nearest whole percentage.

NOTES/COMMENTS:

A Control Area or Reserve Sharing Group must increase their Contingency Reserve Requirement by the CRAF. CRR changes are implemented one month after the end of a reporting quarter and remain in effect for three months.

Area Interchange Error Survey Training Document

Training Document Subsections

A. Effects of Area Interchange Error on the Interconnection

[Policy 1A – Control and Performance]

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

The effect is cumulative for all the CONTROL AREAS in the INTERCONNECTION. The magnitude of the "frequency error" — the difference between actual and scheduled frequency[1] — is directly proportional to the total magnitude of the load and generation imbalances of the control areas in the INTERCONNECTION.

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

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

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

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

B. Area Interchange Error

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

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

for the Eastern and ERCOT INTERCONNECTIONS, and

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

for the Western Interconnection

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

where,

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

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

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

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

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

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

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

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

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

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

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

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

for the Eastern and Texas INTERCONNECTIONS, and

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

for the Western INTERCONNECTION

where,

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

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

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

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

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

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

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

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

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

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

C. Survey Procedures

1. **Issuance of Survey**. Surveys will be conducted for periods selected by the chairman or vice chairman of the Resources Subcommittee or designee, on the chairman's or vice chairman's own motion, in response to specific requests from members of the Subcommittee, or when a time error of a magnitude, specified by the Subcommittee, occurs.

1.1. As soon as possible after the survey period is chosen by the chairman, the chairman shall notify the appropriate Subcommittee members by letter of the survey date and hour, average actual frequency during the survey period, and the date for return of survey data.

1.2. Each Subcommittee member shall notify each reporting CONTROL AREA within the Region in writing that a survey is being requested and the average actual frequency during the survey period. The Subcommittee member shall provide for each CONTROL AREA a copy of survey form "NERC Area Interchange Error Survey."

1.3. Each reporting CONTROL AREA shall return one completed copy of the appropriate table to its Subcommittee member. Each Subcommittee member shall review the CONTROL AREA response and send the individual appropriate table results to the NERC staff.

1.4. The NERC staff shall combine the CONTROL AREA data into one report and send one copy to each Subcommittee member.

1.5. Each Subcommittee member shall be responsible for reproducing and distributing the summary report within their Region.

2. **Instructions for AIE Survey for Eastern and ERCOT INTERCONNECTIONS – AIE Form 1**

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

Line 1: Enter the date and period of the survey (this information is provided by the Resources Subcommittee member's survey request) and the name of the CONTROL AREA.

Line 2: Enter the name of all CONTROL AREAS with which interchange occurred at the time of the survey. Use additional forms if necessary.

Line 3: Enter the mutually agreed upon actual interchange that occurred with each utility for the time of survey; total the entries and place the result in the NET TOTAL column.

Line 4: Enter the mutually agreed upon scheduled interchange with each utility for the time of the survey; total the entries and place the result in the NET TOTAL column. Sign convention for net power into the CONTROL AREA is negative (–), and net power out of the CONTROL AREA is positive (+). Do not include scheduled inadvertent payback on this line.

Line 5: Enter all mutually agreed upon scheduled inadvertent payback with each utility for the time of the survey; total the entries and place the result in the NET TOTAL column. These entries reflect only the portion of the total scheduled interchange with each utility that was used for inadvertent payback. Line 4 + Line 5 = Scheduled Net Interchange, NI_S.

Line 6: Enter the inadvertent interchange (Line 3 – Line 4 – Line 5) occurring with each utility at the time of the survey; total the entries and place the result in the NET TOTAL column.

Line 7: The computed interconnected system frequency error is the value furnished in the survey request letter. Enter the given value here. The given value was computed by taking the difference between the average frequency and the scheduled frequency for the hour being surveyed.

Line 8: Enter the CONTROL AREA'S bias setting. If using a variable bias, enter the integrated bias for the hour.

Line 9: Enter the CONTROL AREA bias obligation. Line 9 = Line 7 x Line 8 x 10.0.

Line 10: Enter all unilateral inadvertent payback that is *not* scheduled with any utility at the time of survey, as in accordance with NERC Operating Guide I.F. (Systems Control – Inadvertent Interchange Management).

Line 11: Enter the adjusted Area Interchange Error. Line 11 = Line 6 Net Total – Line 9 – Line 10.

Line 12: Enter the average ACE (with correct sign) for each of the six ten-minute periods of the hour. (This is the same as the values reported in the CPC survey, except that here it includes the sign.)

Remarks: Please attach a separate sheet with any comments regarding the survey and unusual conditions that may have caused your regulating error.

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

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

Line 1: Enter the date and time of the survey (this information is provided by the Resources Subcommittee member's survey request), and the name of the CONTROL AREA.

Line 2: Enter the name of all utilities with which interchange occurred at the time of the survey. Use additional forms if necessary.

Line 3: Enter the mutually agreed upon actual interchange that occurred with each utility at the time of survey; total the entries and place the result in the NET TOTAL column.

Line 4: Enter the scheduled interchange with each utility at the time of the survey; total the entries and place the NET result in the NET TOTAL column. Sign convention for net power into the CONTROL AREA is negative (–), and net power out of the CONTROL AREA is positive (+). Do not include scheduled inadvertent payback on this line.

Line 5: Enter all mutually agreed upon scheduled inadvertent payback with each utility at the time of the survey; total the entries and place the result in the NET TOTAL column. These entries reflect only the portion of the total scheduled interchange with each utility that was used for inadvertent payback. Line 4 + Line 5 = Scheduled Net Interchange, NI_S.

Line 6: Enter the inadvertent interchange (Line 3 – Line 4 – Line 5) occurring with each utility at the time of the survey; total the entries and place the result in the NET TOTAL column.

Line 7: The computed interconnected system frequency error is the value furnished in the survey request letter. Enter the given value here. The given value was computed by taking the difference between the average frequency and the scheduled frequency for the hour being surveyed.

Line 7a: The computed interconnected time error is the value furnished in the survey request letter. Enter the value here.

Line 8: Enter the CONTROL AREA'S bias setting. If using a variable bias, enter the integrated bias for the hour.

Line 9: Enter the CONTROL AREA bias obligation to correct frequency. Line 9 = Line 7 x Line 8 x 10.0.

Line 9a: Enter the control bias obligation to correct time error. Line 9a = Line 7a x Line 8 x 0.1.

Line 10: Enter all unilateral inadvertent payback that is *not* scheduled with any utility at the time of survey, as in accordance with NERC Operating Guide I.F. (Systems Control X Inadvertent Interchange Management).

Line 11: Enter the Area Interchange Error. Line 11 = Line 6 Net Total – Line 9 – Line 9a – Line 10.

Line 12: Enter the average ACE (with correct sign) for each of the six 10-minute periods of the hour. (This is the same as the values reported in the CPC survey, except that here it includes the sign.)

Remarks: Please attach a separate sheet with any comments regarding the survey and unusual conditions that may have caused your regulating error.

D. Survey Review

1. **Survey Analysis**. Each NERC Resources Subcommittee member shall cross check all input data and analyze the ACE survey results for the CONTROL AREAS within the Region for uniformity, completeness, and compliance to the instructions.

2. **Survey Review**. The NERC Resources Subcommittee may request comments from Regions or CONTROL AREAS relating the causes of excessive ACE and AIE within a CONTROL AREA.

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

Form AIE 1

1.	Date:		Hr. Ending (CST/CDT):					Control Area:				
								Region:				
INTERCHANGE DETAILS (All values in MWh)												
2:	Control Area or Interconnection											Total
3:	Actual Interchange											
4:	Scheduled Interchange											
5:	Scheduled Inadvertent Payback											
6.	Inadvertent Interchange											
AREA INTERCHANGE CALCULATION												
7.	Computed Frequency Deviation		Hz									
8.	Frequency Bias Setting	–	MW/0.1 Hz (negative value)									
9.	Bias Obligation		MWh Line 7 x Line 8 x 10.0									
10.	Unilateral Inadvertent Payback		MWh									
11.	Adjusted Area Interchange Error		MWh Line 6 Total – Line 9 – Line 10									
			1	2	3	4	5	6	Total	Avg		
12.	Integrated ACE for the 6 consecutive Periods of the survey hour		:00-:10	:10-:20	:20-:30	:30-:40	:40-:50	:50-:60		Total/6		

Notes:

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

North American Electric Reliability Council
Area Interchange Error Survey
Western Interconnection

Form AIE 2

1. Date:	Hr. Ending (PST/PDT):	Control Area:
		Region:

INTERCHANGE DETAILS (All values in MWh)

2. Control Area or Interconnection											Total
3. Actual Interchange											
4. Scheduled Interchange											
5. Scheduled Inadvertent Payback											
6. Inadvertent Interchange											

AREA INTERCHANGE CALCULATION

7. Computed Frequency Deviation		Hz
7.5. Computed System Time Error		Seconds
8. Frequency Bias Setting	(–)	MW/0.1 Hz (negative value)
9. Frequency Bias Obligation		MWh Line 7 x Line 8 x 10.0
9.5. Time Error Bias Obligation		MWh s(Line 7.5 x Line 8 x 0.3)*
10. Unilateral Inadvertent Payback		MWh
11. Adjusted Area Interchange Error		MWh Line 6 Total – Line 9 – Line 9.5 – Line 10

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

Notes:
List remarks on separate sheet of paper, including conditions causing regulating errors.
Net power delivered *out* of a control area (over-generation) is positive (+).
Net power received *into* a control area (under-generation) is negative (–).
*s is defined as 1 or 0 as explained on the following page.

Frequency Response Characteristic Survey Training Document

Training Document Subsections

This document includes the purpose and description of the Frequency Response Characteristic (FRC) Survey, describes the complete survey procedure including specific instructions to complete the survey form and discusses the use of survey results.

A. Frequency Response

[Appendix 1A – The Area Control Error Equation]

Frequency Response Characteristic Surveys are conducted to determine the frequency response characteristic of a control area. Accurate measurement of system response is difficult unless the frequency deviation resulting from a system disturbance is significant. Therefore, surveys are usually requested when significant frequency deviations occur.

Disturbances can cause the frequency to increase from loss of load or decrease from loss of generation. Frequency Response Surveys may be requested for either event.

1. Frequency Response Characteristic. For any change in generation/load balance in the INTERCONNECTION, a frequency change occurs. Each CONTROL AREA in the INTERCONNECTION will respond to this frequency change through:

- A load change that is proportional to the frequency change due to the load's frequency response characteristic,[1] and
- A generation change that is inverse to the frequency change due to turbine governor action. The net effect of these two actions is the CONTROL AREA'S response to the frequency change, that is, its *frequency response characteristic*. The combined response of all CONTROL AREAS in the INTERCONNECTION will cause the INTERCONNECTION frequency to settle at some value different from the pre-disturbance value. It will not return frequency to the pre-disturbance value because of the turbine governor droop characteristic. Frequency will remain different until the CONTROL AREA with the generation/load imbalance (referred to as the "Acontingent CONTROL AREA") corrects that imbalance, thus returning the INTERCONNECTION frequency to its pre-disturbance value.

2. Response to Internal and External Generation/Load Imbalances. Most of a CONTROL AREA'S frequency response will be reflected in a change in its actual net interchange. By

[1]Rotating (motor) and inductive loads are the predominating factor. Resistive loads do not change with changing frequency.

monitoring the frequency error (the difference between actual and scheduled frequency) and the difference between actual and scheduled interchange and by using its response to frequency deviation, a CONTROL AREA'S automatic generation control (AGC) can determine whether the imbalance in load and generation is internal or external to its system. If internal, the CONTROL AREA'S AGC should correct the imbalance. If external, the CONTROL AREA'S AGC should allow its generator governors to continue responding through its frequency bias contribution until the contingent CONTROL AREA corrects its imbalance, which should return frequency to its pre-disturbance value.

3. Frequency Bias versus Frequency Response Characteristic (FRC). The CONTROL AREA should set its bias to match its FRC. In doing so, the CONTROL AREA'S bias would exactly offset the tie line flow error ($Ni_A - Ni_S$) of the ACE that results from governor action following a frequency deviation on the INTERCONNECTION. The following sections 4 and 5 discuss the effects of bias on control action and explain the importance of setting the bias equal to the CONTROL AREA'S FRC. The discussion explains the control action on all CONTROL AREAS external to the contingent CONTROL AREA (the CONTROL AREA that experienced the sudden generation/load imbalance) and on the contingent CONTROL AREA itself. While this discussion deals with loss of generation, it applies equally to loss of load, or any sudden contingency resulting in a generation/load mismatch. Each CONTROL AREA'S frequency response will vary with each disturbance because generation and load characteristics change continuously. This discussion also assumes that the frequency error from 60 Hz was zero (all ACE values were zero) just prior to the sudden generation/load imbalance.

For an explanation of the ACE equation, refer to the Area Interchange Error Training Document.

4. Effects of a Disturbance on all CONTROL AREAS External to the Contingent CONTROL AREA. When a loss of generation occurs, an INTERCONNECTION frequency error will occur as rotating kinetic energy from the generators is expended[2]. All CONTROL AREAS' generator governors will respond to the frequency error and increase the output of their generators accordingly. This will cause a change in the CONTROL AREAS' actual net interchange. In other words, Ni_A will be greater than Ni_S for all but the contingent CONTROL AREA, and the result will be a positive flow out of the non-contingent CONTROL AREAS.

If the CONTROL AREAS were using only tie line flow error (i.e., flat tie control ignoring the frequency error), this non-zero ACE would cause their AGC to reduce generation until Ni_A was equal to Ni_S; ACE would then be zero. However, doing this would not help arrest INTERCONNECTION frequency decline because the control areas would not be helping to temporarily replace some of the generation deficiency in the INTERCONNECTION. With the tie-line bias method, the CONTROL AREAS' AGC should allow their governors to continue responding to the frequency deviation until the contingent control area replaces the generation it lost. The resulting tie flow error ($Ni_A - Ni_S$) will be counted as INADVERTENT INTERCHANGE.

In order for the AGC to allow governor action to continue helping in this way, a frequency bias is added to the tie flow error in the ACE equation. This bias is equal in magnitude and opposite in direction to the governor action and should be exactly equal to each CONTROL AREA'S frequency response characteristic measured in MW/0.1 Hz. Then, when multiplied by the frequency error, the bias should exactly counteract the tie flow error portion of the ACE calculation.

[2]An amount of kinetic energy proportional to the power (generation) lost will be withdrawn from the stored energy in the generator rotors throughout the Interconnection. Thus, Interconnection frequency decreases proportionally.

In other words, bias contribution = $10\beta(f_A B f_S)$. ACE will be zero, and AGC will not readjust generation.

The ACE equation now becomes:

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

If the bias setting is greater than the CONTROL AREA'S actual frequency response characteristic, then its AGC will increase generation beyond the governor response, which further helps arrest the frequency decline, but increases INADVERTENT INTERCHANGE. Likewise, if the bias setting is less than the actual FRC, its AGC will reduce generation, reducing the CONTROL AREA'S contribution to arresting the frequency change. In both cases, the control action is unwanted.

5. Effects of a Disturbance on the Contingent CONTROL AREA. In the contingent CONTROL AREA where the generation deficiency occurred, most of the replacement power comes from the INTERCONNECTION over its tie lines from the frequency bias contributions of the other CONTROL AREAS in the INTERCONNECTION. A small portion will be made up internally from the contingent CONTROL AREA'S own governor response (bias contribution). In this case, the difference between Ni_A and Ni_S for the contingent CONTROL AREA is much greater than its frequency bias component. Its ACE will be negative, and its AGC will begin to increase generation. *The contingent CONTROL AREA must take appropriate steps to reduce its ACE to zero within ten minutes of the contingency*. (Reference: Operating Criterion II.A.) The energy supplied from the INTERCONNECTION is posted to the contingent CONTROL AREA'S inadvertent balance, and must be paid back.

B. Survey Procedures

Frequency Response Characteristic Surveys will be conducted to compare each CONTROL AREA'S FRC with respect to its bias setting.

1. Issuance of Survey

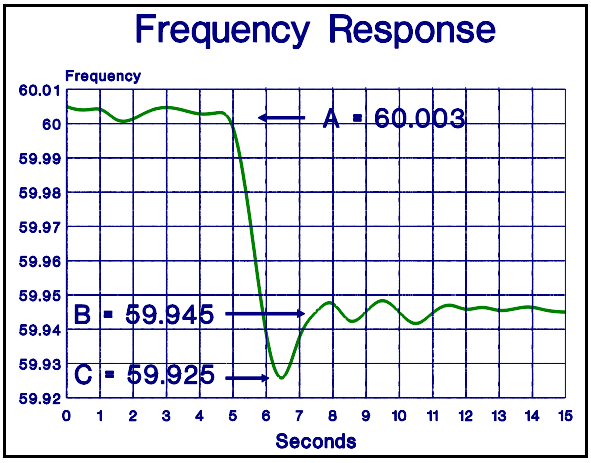
Surveys will be conducted for periods selected by the chairman or vice chairman of the Resources Subcommittee or designee, on the chairman's or vice chairman's own motion, or in response to specific requests from members of the Subcommittee.

- As soon as possible after the survey period is chosen by the chairman, the chairman or vice chairman shall notify each appropriate Subcommittee member by letter of the survey date and time, the frequency points A, B, and C, frequency deviation, and date for the survey to be returned.
- Each Subcommittee member shall notify each reporting CONTROL AREA within the Region by written request. The Subcommittee member shall provide each CONTROL AREA a copy of the survey form "NERC Frequency Response Characteristic Survey."
- Each reporting control area shall return one completed copy of the survey form and a copy of its frequency chart.
- Each Subcommittee member shall review the appropriate control area results and send the copies of survey form results to the NERC staff.
- The NERC staff shall combine the control area data into one report and send one copy to each Subcommittee member.
- Each Subcommittee member shall be responsible for reproducing and distributing the summary report within their Region.

2. Instructions for FRC Survey

The table is the Control Area Frequency Response Characteristic Survey form.

A sample frequency chart is shown in Figure 1 with points A, B, and C labeled. Point A represents the interconnected system frequency immediately before the disturbance. Point B represents the interconnected system frequency at the point immediately after the frequency stabilizes due to governor action but before the contingent control area takes corrective AGC action. Point C represents the interconnected system frequency at its maximum deviation due to the loss of rotating kinetic energy from the turbine generators.



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

Line 1: Enter the date and time of survey period (this information is provided by the RESOURCES SUBCOMMITTEE member's survey request) and the name of the control area.

Line 2: Enter the net interchange of the control area immediately before the survey period (corresponding to Point A). Sign convention for net power into a CONTROL AREA is negative (–), and net power out of a control area is positive (+).

Line 3: Enter the net interchange of the control area immediately after the survey period (corresponding to Point B). Use the same sign convention as Line 2.

A

Line 4: Enter the change in net interchange of the CONTROL AREA. Line 4 = Line 3 – Line 2. For a disturbance that causes the frequency to decrease, this value should be positive except for the contingent CONTROL AREA, in which case it is negative.

Line 5: If the control area completing the survey suffered the loss, enter the load or generation lost by the control area. Otherwise, leave this line blank. Sign convention for generation loss is negative (–) and for load loss is positive (+).

Line 6: Enter the control area response. This value is (Line 4 – Line 5).

Line 7: Enter the change in interconnected system frequency as specified in the letter of transmittal.

Line 8: Enter the frequency response characteristic of the CONTROL AREA based on the change in interconnected system frequency. This value is:

$$FRC = \frac{Line6}{(Line7)10.0}$$

(The factor of 10.0 is used to change the units to MW/0.1 Hz.) This value approximates the frequency response of the control area for this disturbance.

Line 9: Enter the frequency bias setting of the CONTROL AREA.

Line 10: Enter the CONTROL AREA'S net system load immediately before the disturbance.

Line 11: Enter the CONTROL AREA'S total capacity synchronized to the INTERCONNECTION immediately before the disturbance. Jointly owned units should be reported in their entirety by the CONTROL AREA in which they are located.

Lines 12, 13, and 14:

Enter the frequency values you observed from the frequency chart for Points A, B, and C, respectively.

C. Survey Review

Each NERC Resources Subcommittee member shall analyze the survey results of the CONTROL AREAS within their Region. The survey data received on the survey form shall be reviewed for uniformity, completeness, and compliance to the instructions. The NERC Resources Subcommittee will review the total frequency response for the total INTERCONNECTION surveyed to ensure adequate frequency bias exists to maintain the scheduled frequency.

North American Electric Reliability Council
Frequency Response Characteristic Survey

Form FRC 1

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

AREA FREQUENCY RESPONSE CALCULATION

2: Actual Net Interchange Immediately Before Disturbance (Point A)*				**MW**
3: Actual Net Interchange Immediately After Disturbance (Point B)*				**MW**
4: Change in Net Interchange				**MW Line 3 – Line 2**
5: Load (+) or Generation (B) Lost Causing the Disturbance				**MW**
6. Control Area Response				**MW Line 4 – Line 5**
7. Change in Interconnection Frequency from Point A to Point B				**Hz (–) for frequency decrease; (+) for frequency increase**
8. Frequency Response Characteristic				**MW/0.1 Hz Line 6 /(Line 7 x 10.0)**

OTHER INFORMATION

9. Frequency Bias Setting				**MW/0.1 Hz**
10. Net System Demand Immediately Before Disturbance (Point A)				**MW**
11. Synchronized Capacity Immediately Before Disturbance (Point A)				**MW**
12.	**From your charts**	**Frequency at Point A**		**Hz**
13.		**Frequency at Point B**		**Hz**
14.		**Frequency at Point C**		**Hz**

Notes:

Net power delivered *out* of a control area (over-generation) is positive (+).
Net power received *into* a control area (under-generation) is negative (–).

*CONTROL AREAS that have a Net Tie Deviation From Schedule Recorder should obtain these values from that device.

Inadvertent Interchange Accounting Training Document

Training Document Subsections

A. Introduction

[Appendix 1F – Inadvertent Interchange Energy Accounting Practices]

The purpose of this document is to explain inadvertent interchange (inadvertent) accounting. Included within this document are accounting practices that every control area within the North American Electric Reliability Council shall follow. These practices provide a method for isolating and eliminating the source(s) of accounting errors. They may also be used as an aid in identifying the poor control performance that contributes to inadvertent accumulations.

Additional information concerning inadvertent may be found in the NERC Operating Manual under Operating Policy 1F., Inadvertent Interchange.

Simple accounting errors (value or sign) made while recording actual net interchange or scheduled net interchange become operating problems as soon as they become a part of hourly accounting. This occurs because the system dispatcher may be influenced to bilaterally or unilaterally pay back inadvertent or offset a schedule setter to correct a perceived metering error. Viewed from a total interconnected network (Interconnection) perspective, when inadvertent no longer sums to zero due to accounting errors subsequent unilateral pay backs to correct for the "perceived" inadvertent will cause a generation surplus or deficiency on the interconnection. Ultimately this shows up in the form of a continuously recurring time error.

B. Definitions

Adjacent Control Areas: Any control areas within an Interconnection sharing a common tie line or metering point.

Hourly MWh Metered Values: MWh data accumulated (whether by telemetry, telephone, direct meter readings, etc.) on an hourly basis.

Adjustments For Error: Either meter errors, absence of metering data due to communication failure or missing data for whatever cause. The important point is that such adjustments are made between control areas involved in the same manner and at the same times in opposite directions.

C. Interchange Accounting

1. Accounting For Interchange. Accounting for energy between control areas residing within the same Interconnection is both simple and complicated. In theory, and in accordance to NERC Guides, inadvertent interchange is the difference between actual net interchange and scheduled net interchange over a given period, usually an hour. Mathematically it is the time integral of the deviation of a control area's actual net interchange from its scheduled net interchange:

$$NI_I = NI_A - NI_S$$

Where,

NI_I is inadvertent interchange. In accordance with NERC convention, negative values of inadvertent interchange denote a condition of undergeneration and positive values denote overgeneration.

NI_A is actual net interchange. It is the algebraic sum of the hourly integrated energy on a control area's tie lines including pseudo-ties for any jointly owned generating units. Actual net interchange is positive for power leaving the system and negative for power entering.

NI_S is scheduled net interchange. It is defined as the mutually prearranged net energy on a control area□s tie lines including dynamic schedules or fixed schedules for any jointly owned generating units. Scheduled net interchange is positive for power scheduled to be delivered from the system and negative for power scheduled to be received into the system.

2. Actual Net Interchange Energy Accounting. Actual net interchange (metered interchange) between two adjacent control areas over a common tie line is accounted for at a specific point in the line. Furthermore, both control areas shall agree on the amount of energy flow through this point, including any pseudo-tie flows for jointly owned generating units that may exist between the two control areas. Therefore, the sum of metered energy accounted by both control areas over this tie line nets to zero. Since this is true for all control areas within the same Interconnection, the algebraic sum of all metered energy within the same Interconnection is also zero.

3. Scheduled Net Interchange Energy Accounting. All scheduled net interchange (and schedule changes) shall be agreed upon between the control areas involved prior to implementation in regard to magnitude, rate of change, and common starting time. Dynamic schedules and fixed schedules for jointly owned generating units between control areas should be agreed to on an hour-by-hour basis, and included as scheduled interchange. Since every interchange schedule is agreed to by all delivering and receiving control areas within an Interconnection, the algebraic sum of all scheduled net interchange is also zero.

4. Inadvertent Interchange Energy Accounting. As stated previously, inadvertent interchange is the difference between actual net interchange and scheduled net interchange over a given period. Since the algebraic sum of all actual net interchange and the algebraic sum of all scheduled net interchange for any given period is zero within an Interconnection, the sum of all inadvertent interchange is also zero.

D. Inadvertent Interchange Energy Accounting Practices

The practices set forth in this section outline the methods and procedures required to reconcile energy accounting and inadvertent interchange balances.

In order for a control area to properly monitor and account for inadvertent interchange, it shall adhere to the NERC Operating Policies.

1. Accounting Procedures

1.1. On-Peak and Off-Peak Accounting Periods. Each control area is obligated to maintain its inadvertent interchange accounting within two periods, namely, on-peak and off-peak (refer to Appendix A).

1.2. Schedules. All hourly schedules and schedule changes shall be agreed upon between the control areas involved prior to implementation in regard to magnitude, rate of change, and common starting time.

1.3. Dynamic Schedules. Dynamic schedules integrated on an hourly basis shall be agreed upon by the control areas involved subsequent to the hour, but in such a manner as not to impact inadvertent accounts. This is accomplished by ensuring that the hourly actual and scheduled interchange quantities agree between all delivering and receiving parties.

1.4. Daily Accounting. Each control area shall agree with adjacent control areas on the actual net interchange (MWh) and scheduled net interchange (MWh) at least once each day for on-peak and off-peak periods.

1.5. Monthly Accounting. Having agreed to the on-peak and off-peak period accumulations on a daily basis, adjacent control areas shall verify that the accumulated values for the month balance.

1.6. Adjustments for Error. Adjustments shall be made at least once each month to correct for differences between hourly MWh meter totals and the totals derived from register readings at the tie line meters.

1.6.1 Differences. Adjacent control areas shall agree upon the difference determined above and assign this correction to the proper on-peak and off-peak period at the same times and in equal quantities in the opposite directions.

1.6.2 Adjustments. Any adjustments necessary due to known metering errors, franchised territories, transmission losses or other special circumstances shall be made in the same manner.

2. Accounting Periods For Control Areas *Not* Using Daylight Savings Time

Some control areas (and states) do not recognize Daylight Saving Time. Where this is the case, inadvertent interchange accounting periods must be shifted in order to remain coordinated with the rest of the control areas that do recognize Daylight Saving Time.

During the shift to Daylight Saving Time, control areas not recognizing Daylight Saving Time should change their accounting periods as follows:

2.1. For the Eastern and ERCOT Interconnections

2.1.1. Atlantic Time Zone. If the control area is in the Atlantic Time Zone, then the on-peak hours change from Hour Ending (HE) 0900–HE 2400 AST Monday through Saturday to HE 0800–HE 2300 AST Monday through Saturday. Similarly, the off-peak hours change from HE 0100–HE 0800 AST Monday through Saturday to HE 2400–HE 0700 AST Monday through Saturday.

2.1.2 Eastern Time Zone. If the control area is in the Eastern Time Zone, then the on-peak hours change from Hour Ending (HE) 0800–HE 2300 EST Monday through Saturday to HE 0700–HE 2200 EST Monday through Saturday. Similarly, the off-peak hours change from HE 2400–HE 0700 EST Monday through Saturday to HE 2300–HE 0600 EST Monday through Saturday.

2.1.3 Central Time Zone. If the control area is in the Central Time Zone, then the on-peak hours change from HE 0700–HE 2200 CST Monday through Saturday to HE 0600–HE 2100 CST Monday through Saturday. Similarly, the off-peak hours change from HE 2300–HE 0600 CST Monday through Saturday to HE 2200–HE 0500 CST Monday through Saturday.

2.2. For the Western Interconnection

2.1.1. Central Time Zone. If the control area is in the Central Time Zone, then the on-peak hours change from HE 0900–HE 2400 CST Monday through Saturday to HE 0800–HE 2300 CST Monday through Saturday. Similarly, the off-peak hours change from HE 0100–HE 0800 CST Monday through Saturday to HE 2400–HE 0700 CST Monday through Saturday.

2.1.2. Mountain Time Zone. If the control area is in the Mountain Time Zone, then the on-peak hours change from HE 0800–HE 2300 MST Monday through Saturday to HE 0700–HE 2200 MST Monday through Saturday. Similarly, the off-peak hours change from HE 2400–HE 0700 MST Monday through Saturday to HE 2300–HE 0600 MST Monday through Saturday.

2.1.3. Pacific Time Zone. If the control area is in the Pacific Time Zone, then the on-peak hours change from HE 0700–HE 2200 PST Monday through Saturday to HE 0600–HE 2100 PST Monday through Saturday. Similarly, the off-peak hours change from HE 2300–HE 0600 PST Monday through Saturday to HE 2200–HE 0500 PST Monday through Saturday.

3. Accounting for Inadvertent Interchange over DC Tie Lines between Separately Synchronous Interconnections

For the purpose of NERC inadvertent interchange accounting, there shall be no contribution to a control area's inadvertent accumulation due to a dc tie connecting adjacent control areas operating in separate Interconnections.

4. Summary Of Accounting Rules

4.1. Summation of scheduled net interchange. The summation of all scheduled net interchange within an Interconnection shall total zero for any period of time.

4.2. Summation of actual net interchange. The summation of all actual net interchange within an Interconnection shall total zero for any period of time.

4.3. Summation of inadvertent interchange for Interconnection. The summation of all inadvertent interchange within an Interconnection shall total zero for any period of time.

5. Accounting Examples

Daily, total all actual net interchange accumulated during the on-peak and off-peak periods. Do the same with the scheduled net interchange. By period, subtract the totaled scheduled net interchange from the totaled actual net interchange. This will yield on-peak and off-peak inadvertent accumulations for the day. The addition of these two accumulations is the control area=s inadvertent interchange accumulation for the day. All control areas are required to keep an accurate, continuous record of their current balances of on-peak, off-peak, and (net) inadvertent for the day, month, and accumulative to date.

As an example, the Western Interconnection's month-end inadvertent interchange report for February 1995 is included on the following page. Every control area in the Interconnection is included. The sum of each period's inadvertent totals to zero.

An example of an individual control area's month-end data submittal to its Performance Subcommittee representative is also included.

E. Interchange Accounting Practices for Jointly Owned Generating Units

[Appendix 1A – The Area Control Error Equation, Section B – Jointly Owned Units]

1. Jointly Owned Generating Units. It is assumed that every jointly owned generating unit resides within a host control area. It is also assumed that every owner will treat its share of the unit as generation within its own control area. Recipients may account for their share of unit output by one of three methods. All participants in a jointly owned generating unit must agree with the host control area on which of these methods is to be used:

1.1 Scheduled interchange. The host control area and the recipient control area agree on a pre-determined, fixed schedule. Generally, these schedules are manually altered to adjust for unplanned operating conditions at the unit, e.g., if the unit unexpectedly trips out of service.

1.2 **Dynamically scheduled interchange.** The host control area and recipient control area share an electronic signal indicating the real-time power transfer from the unit to the recipient. The host control area and recipient control areas see this transfer as a continually changing schedule between the two control areas. It is recommended that after-the-fact adjustments for month-end accumulators or erroneous signals be corrected in future operating periods and not be back-corrected.

1.3 **As a pseudo-tie.** The host control area and the recipient control area share an electronic signal indicating the real-time energy transfer from the unit to the recipient. The host control area and the recipient control area see this transfer as continually changing metered interchange between the two control areas. It is recommended that after-the-fact adjustments for month-end accumulators or erroneous signals be corrected in future operating periods and not be back-corrected.

F. Interchange Accounting Practices for Regulation Service

If a control area provides regulation service for another control area, it generally will occur in one of two ways:

1. **Supplemental Regulation.** The control area providing supplemental regulation service will receive a signal representing all or a portion of the other control area's ACE. Control areas participating in supplemental regulation are not required to make any changes to their accounting systems. Supplemental regulation can be implemented as a dynamic schedule or a pseudo-tie. Both control areas need to use the same method.

2. **Overlap Regulation.** The control area providing overlap regulation service will include all of the other control area's tie lines and schedules in its (the providing control area's) AGC equation. Entities participating in overlap regulation are required to notify the control area providing the regulation of all interchange schedules with other control areas before they are implemented. This is necessary to maintain the integrity of central coordinated control. Ultimate responsibility for energy accounting lies solely with the control area providing the overlap regulation service.

	ON-PEAK			OFF-PEAK			TOTAL		
	Previous Accum.	Net For Month	Carried Forward	Previous Accum.	Net For Month	Carried Forward	Previous Accum.	Net For Month	Carried Forward
B. C. Hydro & Power Authority	726	(1,191)	(465)	582	(1,114)	(532)	1,308	(2,305)	(997)
Bonneville Power Administration	(645)	926	281	1,504	(1,064)	440	859	(138)	721
Chelan County P.U.D. #1	72	(132)	(60)	11	(70)	(59)	83	(202)	(119)
Douglas County P.U.D. #1	3	2	5	0	6	6	3	8	11
Grant County P.U.D. #2	(4)	(54)	(58)	(25)	(29)	(54)	(29)	(83)	(112)
Idaho Power Company	691	(842)	(151)	(73)	87	14	618	(755)	(137)
Montana Power Company	6	43	49	(9)	7	(2)	(3)	50	47
Pacificorp – East	(221)	1,000	779	181	(64)	117	(40)	936	896
Pacificorp – West	(52)	(279)	(331)	(66)	50	(16)	(118)	(229)	(347)
Portland General Electric Company	(109)	108	(1)	35	(193)	(158)	(74)	(85)	(159)
Puget Sound Power & Light Company	45	(29)	16	(9)	(66)	(75)	36	(95)	(59)
Seattle City Light	8	(6)	2	(7)	11	4	1	5	6
Sierra Pacific Power Company	4	(13)	(9)	(72)	202	130	(68)	189	121
Tacoma City Light	(3)	(6)	(9)	(60)	(8)	(68)	(63)	(14)	(77)
TransAlta Utilities Corporation	(33)	(6)	(39)	(571)	(52)	(623)	(604)	(58)	(662)
Washington Water Power Company	1	69	70	(7)	21	14	(6)	90	84
Los Angeles Department of Water & Power	219	117	336	(419)	538	119	(200)	655	455
Pacific Gas & Electric Company	(2,374)	(621)	(2,995)	(1,974)	599	(1,375)	(4,348)	(22)	(4,370)
San Diego Gas & Electric Company	382	(369)	13	(96)	99	3	286	(270)	16
City of Pasadena	(539)	(26)	(565)	490	31	521	(49)	5	(44)
Nevada Power Company	562	(1,797)	(1,235)	161	(832)	(671)	723	(2,629)	(1,906)
Southern California Edison Company	3,084	1,420	4,504	1,670	(1,431)	239	4,754	(11)	4,743
Comision Federal de Electricidad	27	(5)	22	(3)	18	15	24	13	37
Arizona Public Service Company	(625)	891	266	(227)	855	628	(852)	1,746	894
El Paso Electric Company	27	5	32	(21)	42	21	6	47	53
Imperial Irrigation District	(287)	1,354	1,067	1,021	814	1,835	734	2,168	2,902
Public Service Company of New Mexico	108	68	176	255	236	491	363	304	667
Salt River Project	158	80	238	246	146	392	404	226	630
Tucson Electric Power Company	76	(73)	3	(55)	17	(38)	21	(56)	(35)
Western Area Power Administration – LC	(41)	111	70	(41)	114	73	(82)	225	143
Public Service Company of Colorado	659	1,282	1,941	(263)	257	(6)	396	1,539	1,935

Western Area Power Administration - UM	942	240	1,182	1,516	87	1,603	2,458	327	2,785
Western Area Power Administration - CM	(2,867)	(2,267)	(5,134)	(3,674)	686	(2,988)	(6,541)	(1,581)	(8,122)
TOTAL	0	0	0	0	0	0	0	0	0

PACIFICORP – EAST

INADVERTENT INTERCHANGE ACCOUNTING SUMMARY

FEBRUARY 1995 – CENTRAL STANDARD TIME

	ON-PEAK INTERCHANGE			OFF-PEAK INTERCHANGE			TOTAL INTERCHANGE		
	Actual	Scheduled	Inadvertent	Actual	Scheduled	Inadvertent	Actual	Scheduled	Inadvertent
ADJACENT CONTROL AREA	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh
Arizona Public Service Company	62,877	116,239	(53,362)	31,912	40,130	(8,218)	94,789	156,369	(61,580)
Idaho Power Company	138,439	(70,517)	208,956	163,561	3,796	159,765	302,000	(66,721)	368,721
Los Angeles Dept. of Water and Power	89,226	66,248	22,978	38,487	19,511	18,976	127,713	85,759	41,954
Montana Power Company	18,640	7,582	11,058	53,576	36,771	16,805	72,216	44,353	27,863
Nevada Power Company	64,464	32,490	31,974	49,430	24,660	24,770	113,894	57,150	56,744
PacifiCorp – West	(233,626)	(22,214)	(211,412)	(159,770)	36,224	(195,994)	(393,396)	14,010	(407,406)
Sierra Pacific Power Company	23,482	53,827	(30,345)	17,497	37,582	(20,085)	40,979	91,409	(50,430)
Western Area Power Admin. -- CM	(63,300)	(84,453)	21,153	(28,895)	(32,812)	3,917	(92,195)	(117,265)	25,070
TOTAL	100,202	99,202	1,000	165,798	165,862	(64)	266,000	265,064	936

	ON-PEAK	OFF-PEAK	NET
Previous Accumulation	-221	181	-40
Net for Month	1,000	(64)	936
Carried Forward	779	117	896

Prerequisite Approvals and Activities

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this set Balance Resources and Demand standards can be implemented.

As part of this implementation plan, the drafting team is recommending that some Version 0 Balance Resources and Demand requirements be retired because they will be displaced with Version 1 Balance Resources and Demand requirements.

Effective Date

The following table shows the proposed effective dates for the Version 1 Balance Resources and Demand Standards as well as for the conforming modifications to Version 0 Balance Resources and Demand Standards. The effective date is contingent on the approval of the reliability standards by a vote of the ballot pool that is tentatively scheduled for August, 2006. The effective date is also contingent on adoption of these Standards by the NERC Board of Trustees. The Board will approve the final effective date when it adopts the standards for implementation. These standards are scheduled for consideration by the Board on November 2, 2006.

Version 1 Standard	Proposed Effective Date	Reason for Delay in Implementation
BAL-007 Balance of Resources and Demand	9 months after BOT adoption	Entities that didn't participate in the field test need to update system operator tools so that system operators can monitor BAALs and Frequency Limits.
BAL-008 Frequency and Area Control Error	9 months after BOT adoption	Entities that didn't participate in the field test need to update system operator tools so that system operators can monitor BAALs and Frequency Limits.
BAL-009 Actions to Return Frequency to within Frequency Trigger Limits	9 months after BOT adoption	Entities that didn't participate in the field test need to update system operator tools so that system operators can monitor BAALs and Frequency Limits.
BAL-010 Frequency Bias Settings	3 months after BOT adoption	Time needed for entities to update their frequency bias settings.
BAL-011 Frequency Limits	Effective upon BOT adoption	Limits have already been established for each Interconnection
BAL-012 Balancing Authority Area Control Error Limits	6 months after BOT adoption	New frequency bias settings are needed before BAALs can be established.

Following the approval of the BOT, prior to the effective date any BA can begin operating under the Version 1 BRD standards with the approval of the Regional Compliance Manager.

Version 0 Standard	Proposed Effective Date
BAL-001 Real Power Balancing Control Performance	Retire when compliance with BAL-007 becomes effective
BAL-002 Disturbance Control Performance	Retire when compliance with BAL-007 through BAL-009 becomes effective
BAL-003 Frequency Response and Bias	Retire when compliance with BAL-010 becomes effective
BAL-005 Automatic Generation Control	Modifications effective when BAL-007 through BAL-009 become effective

Compliance with Balance Resources and Demand Standards

Once the Version 1 Balance Resources and Demand Standards are effective, the responsible entities identified in each of the standards must comply with the requirements in that standard. The following maps the Balance Resources and Demand requirements to each applicable function. Note that some of the standards in this set are revised Version 0 standards. Entities must continue to comply with all requirements in approved Version 0 Standards until the requirements in the approved Version 0 Standards are replaced or retired.

For example, BAL-001 should be retired when BAL-007 becomes effective. BAL-001 has requirements for Balancing Authorities. The Balancing Authority is responsible for compliance with all requirements in BAL-001 until the requirements in BAL-007 becomes effective.

Recommended Modifications to Version 0 Standards

The following table shows the Balance Resources and Demand standard drafting team's recommendations for modifying or deleting some of the following Version 0 Balance Resources and Demand standards:

- BAL-001 -Real Power Balancing Control Performance
- BAL-002 - Disturbance Control Performance
- BAL-003 - Frequency Response and Bias
- BAL-005 - Automatic Generation Control

Justification for these recommendations is provided in the table.

Version 0 Standard	Recommendation	Reason
BAL-001 -Real Power Balancing Control Performance	Retire entire standard	BAL-001 requires compliance with CPS1 and CPS2; CPS1 is addressed in the new BAL-007; CPS2 is being retired based on stakeholder consensus
BAL-002 - Disturbance Control Performance	Retire entire standard	DCS is being retired based on stakeholder consensus.
BAL-003 - Frequency Response and Bias	Retire entire standard	BAL-003 requires calculation of frequency bias, but the requirements aren't as objective as desired; BAL-010 contains more objective requirements for the calculation of frequency bias.
BAL-005 - Automatic Generation Control	Revise standard to remove references to DCS	BAL-005 contains some language in the compliance elements that require Balancing Authorities to keep or provide data from DCS calculations. Since the requirement to calculate and report DCS is being retired, these data retention requirements should also be retired.

Functions That Must Comply with the Proposed Standards

Standard	Functions That Must Comply With the Requirements
BAL-007 Balance of Resources and Demand	Balancing Authority (All requirements)
BAL-008 Frequency and Area Control Error	Reliability Coordinator (All requirements)
BAL-009 Actions to Return Frequency to within Frequency Trigger Limits	Balancing Authority (All requirements)
BAL-010 Frequency Bias Settings	Balancing Authority (Requirements 1-7) Standards Developer (Requirement 8)
BAL-011 Frequency Limits	Standards Developer (All requirements)
BAL-012 Balancing Authority Area Control Error Limits	Standards Developer (All requirements)

Reference materials will be developed and posted with the Balance Resources and Demand Standard Drafting Team information on the NERC website.

Item 4. NERC Active Resources Subcommittee Projects — Status

Discussion

Carlos Martinez and Terry Bilke will provide a status report and lead a discussion on the following projects related to the Resources Subcommittee.

Item 4.a ACE-Frequency Application Project (Project 2000-3) — Carlos Martinez

The Consortium for Electricity Reliability Technology Solutions (CERTS) has distributed the ACE-Frequency Application version 3.5. Mr. Martinez, CERTS project manager, will report on the status of the project and future enhancements.

Action

Project Review Team: Leader-Terry Bilke, Raymond Vice, Sydney Niemeyer, Robert Rhodes, Bill Herbsleb, John Tolo, Bart McManus, Tom Vandervort
ACE-Frequency Application (NERC Project 2000-03) — A small Resources Subcommittee team will review the issues and address the project parameters. The goal is to recommend expectations, priorities, uses, methodologies, specifications, timelines, and results. Collaboration with Operating Reliability Subcommittee (ORS), Reliability Coordinators Working Group (RCWG), NERC Projects, NERC Training Dept, NERC IT, etc. to be initiated as necessary.

Action

Project Review Team: Leader-Terry Bilke, Robert Rhodes, Tom Vandervort
ACE-Frequency Application (NERC Project 2000-03) — A small Resources Subcommittee team will review the issues and address the project parameters. The goal is to recommend training lessons content, on-line help application, user friendly training tools. Collaboration with ORS, RCWG, NERC Projects, NERC Training Dept, etc. to be initiated as necessary.

Item 4.b–4.e AIE Monitoring, CPS1 & BAAL Monitoring, Frequency-Phasor Monitoring, and Inadvertent Interchange Applications Projects — Terry Bilke and Carlos Martinez

Messrs. Bilke and Martinez will discuss the current status of these projects, the next steps for full deployment, challenges and problems that have arisen, and Resources Subcommittee recommendations to move the projects forward.

Item 4.b AIE Monitoring Application Project (Project 2000-4)

Action

Project Review Team: Leader-Don Badley, Raymond Vice, Bart McManus, John Tolo, Terry Bilke, Don McInnis, Mike Potishnak, Tom Vandervort, Brian Nolan
AIE Monitoring Application (NERC Project 2000-04) – A small Resources Subcommittee team will review the issues and address the project parameters. The goal is to recommend expectations, priorities, uses, methodologies, specifications, timelines, and results. Collaboration with ORS, RCWG, NERC Projects, NERC Training Dept, NERC IT, etc. to be initiated as necessary.

Item 4.c CPS1 & BAAL Monitoring Application (Project 2001-38)

Action

Project Review Team: Leader-Raymond Vice, Doug Hils, Mark Henry, Sydney Niemeyer, Don Badley, John Tolo, Bart McManus, Tom Vandervort
CPS1 & BAAL Monitoring Application (NERC Project 2001-38) – A small Resources Subcommittee team will review the issues and address the project parameters. The goal is to recommend expectations, priorities, uses, methodologies, specifications, timelines, and results. Collaboration with ORS, RCWG, NERC Projects, NERC Training Dept, NERC IT, etc. to be initiated as necessary.

Item 4.d Frequency Phasor Monitoring Application Project (Project 2005-6)

Action

Project Review Team: Leader-Raymond Vice, Frequency Task Force, Tom Vandervort
Frequency-Phasor Monitoring Application (NERC Project 2005-06) – A small Resources Subcommittee team will review the issues and address the project parameters. The goal is to recommend expectations, priorities, uses, methodologies, specifications, timelines, and results. Collaboration with ORS, RCWG, NERC Projects, NERC Training Dept, NERC IT, etc. to be initiated as necessary.

Item 4.e Inadvertent Interchange Application Project (SPP Inadvertent Tool Migration) (Project 2001-37)

Project Review Team: Leader-Don Badley, Inadvertent Task Force, someone from Southwest Power Pool (Robert Rhodes will be the point of contact to identify who this person will be), Tom Vandervort
Inadvertent Interchange Application (NERC Project 2001-37) – A small Resources Subcommittee team will review the issues and address the project parameters. The goal is to recommend expectations, priorities, uses, methodologies, specifications, timelines, and results. Collaboration with ORS, RCWG, NERC Projects, NERC Training Dept, NERC IT, etc. to be initiated as necessary.

Item 4.f DOE Eastern Interconnection Phasor Project — Terry Bilke, Carlos Martinez, Bob Cummings

Messrs. Bilke (who is also the EIPP Real-time Tools Working Group Chairman), Martinez, and Cummings will lead a discussion on the DOE Eastern Interconnection Phasor Project (EIPP) project which contains significant grid monitoring and analysis capabilities. The NERC Reliability Assessment and Performance Analysis Program would like to work in conjunction with the subcommittee to develop a strategy to use the EIPP data and displays for future system monitoring and analysis. Bob Cummings will meet with the subcommittee during this meeting to begin discussions and to gather ideas on using the EIPP for Eastern Interconnection frequency analysis, event analysis, frequency/spectral analysis, situational awareness, etc.

Information on the EIPP can be found at: http://phasors.pnl.gov/EIPP_About.html

Item 5. Frequency Performance

Items 5.a–5.e Western, Eastern, and ERCOT Frequency, CPS1 and CPS2 Data Trends, and DCS Data Trends

Discussion

The subcommittee will discuss the frequency data, surveys, and trends in the Interconnections.

Attachments

To be sent under separate cover.

Item 5.f Inadvertent Interchange Balances — Joe Emde, Don Badley, Terry Bilke

Discussion

The subcommittee will discuss the inadvertent interchange balances. The regional reliability organization subcommittee representatives are requested to show the data to the regions and stress the importance of balancing inadvertent interchange in a timely manner (as soon as reasonably possible).

Each Resources Subcommittee regional representative is requested to contact the balancing authority with bias less than 1% of peak, verify they are aware of BAL-003-0, R5, and ask if they are sure they want to use the bias they reported. The subcommittee is available to assist balancing authorities as necessary.

Standard BAL-003-0, Frequency Response and Bias

> R5. Balancing authorities that serve native load shall have a monthly average Frequency Bias Setting that is at least 1% of the balancing authority's estimated yearly peak demand per 0.1 Hz change.

Attachments

To be sent under separate cover.

Item 5.f Potential Joint Meeting with ORS, RCWG, and IS

Discussion

The subcommittee will use this agenda item as a place-holder for potential joint meeting between the Resources Subcommittee (RS), Operating Reliability Subcommittee (ORS), Reliability Control Working Group (RCWG), and the Interchange Subcommittee (IS).

Item 6. Time Error

Discussion

The subcommittee will discuss the time error correction trends in the Interconnections.

Attachments

Time error reports to be sent under separate cover.

Item 7. Future Meetings

Wednesday, September 20, 2006 Thursday, September 21, 2006 Friday, September 22, 2006	8 a.m.–5 p.m. 8 a.m.–5 p.m. 8 a.m.–noon	Québec City, QU
Wednesday, November 15, 2006 Thursday, November 16, 2006 Friday, November 17, 2006	8 a.m.–5 p.m. 8 a.m.–5 p.m. 8 a.m.–noon	Fort Lauderdale, FL

Notes:

1. Schedule meetings before the Operating Committee and Planning Committee meetings, whenever possible.
2. Avoid scheduling meetings 30 days before NERC Board of Trustees meetings.
3. 2006 Resources Subcommittee meetings are scheduled to coincide with the Interchange Subcommittee, Operating Reliability Subcommittee, and the Reliability Coordinator Working Group. Joint meetings to discuss mutual issues may be arranged.