Appendix 1F – Inadvertent Interchange Dispute Resolution Process, Error Adjustment Procedures, and On- and Off-Peak Periods

Version 1a, Draft 1

For "Immediate Action" ballot following the November 19 – 21, 2002, standing committee meetings.

Revisions:

1. **Title**
2. **Subheadings**
3. **Section C, "On-Peak and Off-Peak Periods"**

Approved by SAC, December 19, 2002. To be presented to NERC BoT in February, 2003, for approval and implementation.

Appendix Subsections

Introduction

Adjacent CONTROL AREAS that cannot mutually agree upon their respective Net Interchange quantities by the 10th calendar day of the following month shall submit a report to their respective Resources Subcommittee representative. The report shall describe the nature and the cause of the dispute as well as a process for correcting the discrepancy. Should the submitted processes not work, the process for resolving the dispute is described herein.

A. Dispute Resolution

1. **Regional Subcommittee Representative reporting requirements.** The Resources Subcommittee representative shall accept the CONTROL AREA'S report describing the disputed values. To comply with the reporting requirements of Policy 1F Standard 5.2.2. that representative shall contact the Resources Subcommittee representative for the opposing CONTROL AREA (if the dispute is between CONTROL AREAS in different Regions). The representative(s) shall determine a set of values, which will be reported to NERC. The report(s) will identify:

1.1. The names of the disputing CONTROL AREAS.

1.2. The reported monthly Net Interchange Schedule (On-Peak and Off-Peak) between the disputing CONTROL AREAS.

1.3. The mutually agreed to monthly Net Interchange Schedule (On-Peak and Off-Peak) between the disputing CONTROL AREAS (used to compute the Regional Inadvertent Interchange).

1.4. The reported monthly Net Actual Interchange (On-Peak and Off-Peak) between the disputing CONTROL AREAS.

1.5. The mutually agreed to monthly Net Actual Interchange (On-Peak and Off-Peak) between the disputing CONTROL AREAS (used to compute the Regional Inadvertent Interchange).

2. **NERC Staff reporting requirements.** The NERC staff representative to the Resources Subcommittee shall receive the Regional reports and, using the mutually agreed to data, compile a balanced INADVERTENT INTERCHANGE SUMMARY report. This report will also include a tabulated list of the CONTROL AREAS that have disputed data, as well as the magnitude of the data in dispute. This report will be distributed to the Operating Committee as well as the Resources Subcommittee by the 1st of the succeeding month.

3. **Dispute Resolution.** All disputes between CONTROL AREAS within a Region shall be referred to the regional process for dispute resolution to resolve the dispute on an informal basis within 30 days of the issuance of the NERC INADVERTENT INTERCHANGE SUMMARY report.

3.1. All disputes between CONTROL AREAS in different Regions shall be referred to the respective Regions' Operating Committee representatives, or other Regional-approved representatives, for resolution on an informal basis within 30 days of the issuance of the NERC INADVERTENT INTERCHANGE SUMMARY report.

3.2. In the event that the informal procedures do not resolve the dispute within 30 days, the dispute shall be submitted to binding arbitration as described below.

4. **Binding Arbitration.** A professional arbitration service will provide each of the parties in the dispute an opportunity to be heard. Within 30 days of those presentations, the arbitrator shall issue a decision. The decision and the rationale for the decision shall be provided in writing to the disputing parties.

B. Error Adjustment Procedure

Periodic Adjustments shall be made to correct for differences between hourly MWh meter totals and the totals derived from register readings of the tie-line meters. Adjacent CONTROL AREAS shall agree upon the difference determined above and assign this correction to the proper on-peak and off-peak period at the same times and in equal quantities in the opposite directions. Any adjustments necessary due to known metering errors, franchised territories, transmission losses or other special circumstances shall be made in the same manner.

Adjustments to schedules shall only be made if an incorrect schedule was used by one CONTROL AREA. Schedules shall not be adjusted after-the-fact due to marketing considerations or adjustments during the billing procedure.

C. On-Peak and Off-Peak Periods

Section C rewritten so that it does not need updating each year.

1. On-Peak and Off-Peak Hours (Monday Through Sunday)

1.1. **On- and off-peak designation.** The hourly inadvertent energy created by a Control Area is classified as either on-peak or off-peak inadvertent. The peak designation assigned is a function of hour of day, day of week, time zone, prevailing time (standard or daylight savings), and special holiday status.

1.2. **Daylight saving time.** The on-peak to off-peak and off-peak to on-peak boundary hours are unaffected by transitions to or from daylight savings time. If a Control Area remains on either standard or daylight savings time throughout the year, their inadvertent accounting practices shall use prevailing time.

1.3. **On-peak hours.** Each Interconnection has a reference time zone and standardized on-peak and off-peak periods. On-peak periods are summarized in the table below for each Interconnection. Sundays and special holidays are designated to be off-peak periods for the entire day. Hours for Monday through Saturday that are not shown in the table below are also designated as off-peak hours.

2. On-Peak Hours For Monday Through Saturday In Hour-Ending Format

Interconnection	*Reference Time Zone*	*Hour Ending*	
		From	*To*
Eastern	Central	0700	2200
ERCOT	Central	0800	2200
Western	Pacific	0700	2200

3. Additional Off-Peak Holidays for the Eastern and Western Interconnections

There are six identified holidays each year:

- New Year's Day
- Memorial Day
- Independence Day
- Labor Day
- Thanksgiving Day
- Christmas Day

ERCOT does not specify holidays as off-peak days.

Based on historic trends, the Resources Subcommittee decided that holidays can be treated consistently.

If any of these holidays fall on a Sunday, the following Monday will be considered an off-peak day. Otherwise, the off-peak day will be the holiday itself.

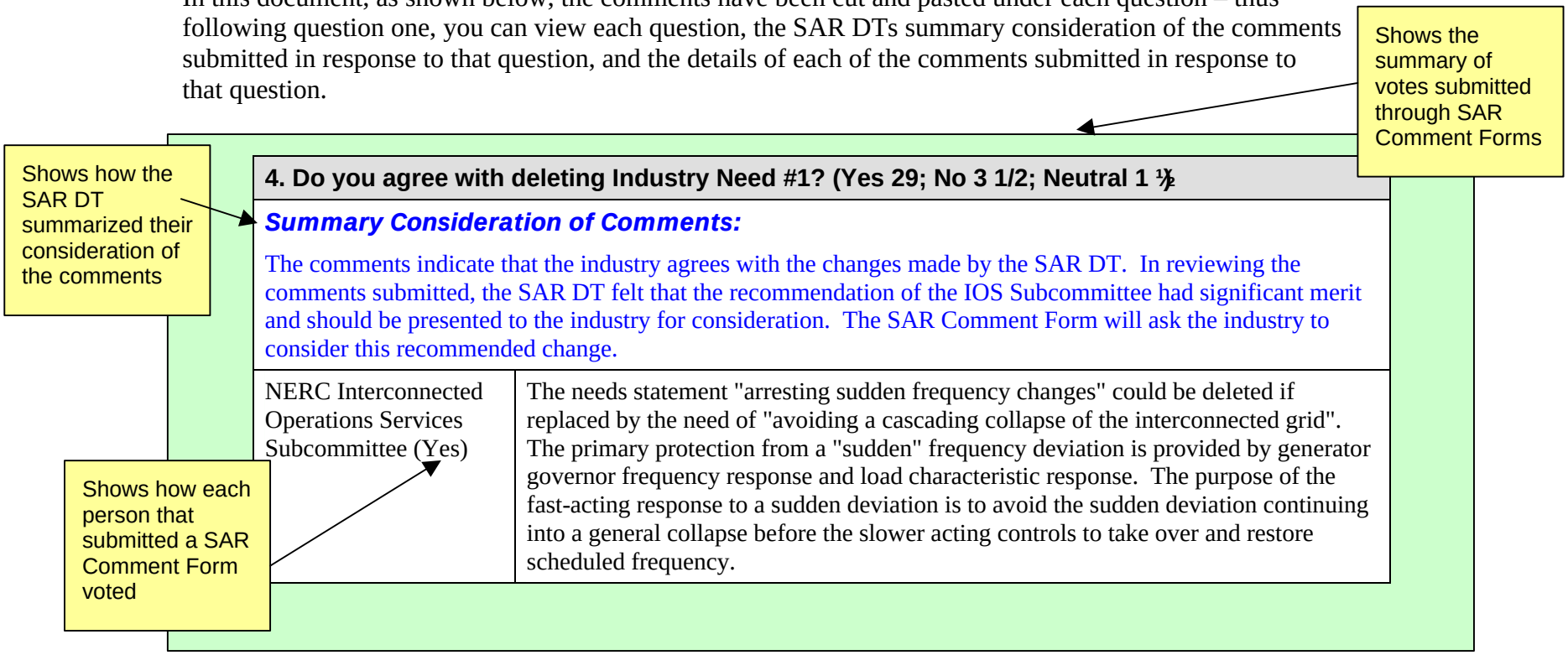
Summary of Comments, Organized By Question Number

Background:

The Balance Resources and Demand SAR was posted for a second public comment period from June 3 through July 12, 2002. The SAR DT asked industry participants to provide feedback on the revisions made to the SAR through a special SAR Comment Form. There were 35 sets of comments submitted via this special SAR Comment Form. The comments can be viewed in their original format at:

ftp://www.nerc.com/pub/sys/all_updl/standards/sar/BalResDemnd_Comments.pdf

In this document, as shown below, the comments have been cut and pasted under each question – thus following question one, you can view each question, the SAR DTs summary consideration of the comments submitted in response to that question, and the details of each of the comments submitted in response to that question.



The Balance Resources and Demand SAR Drafting Team met and considered each of the sets of responses to the questions posed with the SAR Comment Form. The questions were aimed at gathering feedback on the changes made (or proposed to be made) to the SAR. The SAR DT's consideration of comments is

provided in blue text immediately under each question. In most cases, a single response has been provided to show how the comments were considered.

In some cases, the SAR DT provided a short note to indicate how a unique comment was considered

To make it easier to review the comments, the SAR DT has also provided a copy of the SAR (pages 4-10), showing how the SAR has been changed from the 1st to 2nd postings, and also showing how it has been changed from the 2nd posting to the 3rd posting.

- The comments submitted by industry participants and included in this document were addressing the changes made to the SAR from the 1st to the 2nd posting.
- The comments submitted by industry participants and included in this document were used as the basis for making changes to the SAR for the 3rd posting.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give EVERY comment serious consideration in this process! If you feel there has been an error or omission, you can contact Tom Vandervort in the NERC office. Tom can be reached at 609-452-8060 or at tom.vandervort@nerc.com. Or you can contact the Standards Process Manager, Maureen Long at 305-891-5497 or at spm@nerc.com.

Index to Questions, Comments and their Considerations

Changes to the Balance Resources and Demand SAR as a Result of Comments Submitted by Industry Participants

Title	
Original, 2nd Posting and 3rd Posting:	Balance Resources and Demand
Purpose of Standard	
Original	Maintain scheduled frequency within an Interconnection.
2nd Posting	Maintain Interconnection scheduled frequency within a predefined frequency profile under all conditions (i.e. normal and abnormal). The standard requires that Balancing Authorities (BAs) contribute their fair share to maintaining scheduled interconnection frequency
3rd Posting (Combined with Industry Need)	To maintain Interconnection scheduled frequency within a predefined frequency profile under all conditions (i.e. normal and abnormal), to prevent unwarranted load shedding and to prevent cascading collapse of the interconnected grid.
Industry Need for Standard	
Original	Load-resource balance is necessary to: 1. Arrest sudden frequency changes in the Interconnection caused by generation failure or load interruption. 2. Maintain Scheduled Frequency in the Interconnection. Frequency Error creates Time Error in the Interconnection. Operating well below 60 Hz can cause underfrequency load shedding. 3. Minimize unscheduled power flows within the Interconnection that can cause operating limit violations. 4. Minimize Inadvertent Interchange accumulation between the Balancing Authority and the Interconnection.
2nd Posting	– Maintain Interconnection scheduled frequency under all conditions, i.e. normal and abnormal – Prevent unwarranted underfrequency load shedding – Control Time Error in the Interconnection
3rd Posting **(Combined with Purpose)**	To maintain Interconnection scheduled frequency within a predefined frequency profile under all conditions (i.e. normal and abnormal), to prevent unwarranted load shedding and to prevent cascading collapse of the interconnected grid.

Brief Description:	
Original	The Load-Resource Balance Standard requires that each Balancing Authority maintain a close match between its loads and resources in real time. The Standard accomplishes this through four measures that cover various time frames and situations: 1. Frequency Response Measure (FRM) – FRM arrests short-term (0-1 minute) frequency deviation following a sudden mismatch between generation and load. Adherence to the FRM ensures there are sufficient frequency responsive resources that quickly (within seconds) stabilize Interconnection frequency whenever load or generation changes rapidly before operator actions. (Note that FRM does not return the Interconnection to its scheduled frequency, only arrest the frequency change.) 2. Control Performance Measure 1 (CPM1) – CPM1 measures the Balancing Authority's one-minute average Area Control Error with respect to Interconnection frequency. Compliance with CPM1 helps maintain Interconnection frequency on schedule. 3. Control Performance Measure 2 (CPM2) –CPM2 measures the Balancing Authority's 10-minute average Area Control Error. Compliance with CPM2 helps minimize unscheduled power flows that can cause transmission operating limit violations. 4. Disturbance Control Measure (DCM) –DCM ensures that the Interconnection returns to its scheduled frequency within a defined period following a sudden generation or load change (a "disturbance.") This measure requires the responsible Balancing Authority to quickly return its Area Control Error to an acceptable level.Procedural Requirements: Each Balancing Authority shallhave the necessary AGC facilities at its disposal to calculate an area control error (ACE) value (See Standard Technical Reference document). Each Balancing Authority shall maintain its ACE within specific limits as defined by four measures. FRM CPM1 CPM2 DCM
2nd Posting	Maintain Interconnection frequency performance within a targeted frequency profile as demonstrated through control performance measures. This standard will require the use of a technically defensible mathematical method to enable each Interconnection to disburse control responsibility among its entities to achieve its targeted Interconnection frequency profile.
3rd Posting	Maintain Interconnection frequency performance within a targeted frequency profile as demonstrated through control performance measures. This standard will require the use of a technically defensible mathematical method to enable each Interconnection to disburse control responsibility among its entities to achieve its targeted Interconnection frequency profile. This standard will require that the Reliability Authority monitor system frequency and have the authority to direct actions (to control frequency) that include load shedding.

Detailed Description:	
Original	(No Detailed Description Included)
2nd Posting	Detailed Description of New Standard This Standard requires that each Balancing Authority maintain a close match between its resources and demand in real time. The Standard accomplishes this through measures that cover various time frames and situations: Control Performance Measure 1 (CPM1) – CPM1[1] measures the Balancing Authority's one-minute average Area Control Error with respect to Interconnection frequency. Compliance with CPM1 helps maintain Interconnection frequency on schedule. Control Performance Measure 2 (CPM2) – CPM2[1] measures the Balancing Authority's 10-minute average Area Control Error. Compliance with CPM2 helps minimize unscheduled power flows that can cause transmission operating limit violations. Disturbance Control Measure (DCM) – DCM[1] ensures that the Interconnection returns to its scheduled frequency within a defined period following a sudden generation or load change (a "disturbance.") This measure requires the responsible Balancing Authority to quickly return its Area Control Error to an acceptable level.
3rd Posting	This Standard requires that each Balancing Authority maintain a close match between its resources and demand in real time. The Standard requires that the Reliability Authority monitor system frequency and Balancing Authority activities and direct action when the Reliability Authority determines that the interconnected electric system is at risk. The Standard accomplishes this through measures that cover various time frames and situations: Control Performance Measure 1 (CPM1) – CPM1 measures the Balancing Authority's one-minute average Area Control Error with respect to Interconnection frequency. Compliance with CPM1 helps maintain Interconnection frequency on schedule. Control Performance Measure 2 (CPM2) – CPM2 measures the Balancing Authority's 10-minute average Area Control Error. Compliance with CPM2 helps bound net interchange power flows that can cause transmission operating limit violations. Disturbance Control Measure (DCM) – DCM requires that the deficient BA return to an acceptable balance level within a defined period, following a sudden generation or load change. This measure requires the responsible Balancing Authority to quickly return its Area Control Error to an acceptable level. (Note: The proposed CPM1 is equivalent to CPS1, CPM2 is the equivalent of CPS2, and DCM is equivalent to DCS, covering identical time horizons. However, the industry may request changes to these measures, through posted comments on this SAR or the draft standard.)

Note – this is the information that was in the footnote for the 2nd posting of this SAR, slightly modified.

Functions			
Original and 2nd Posting		Reliability Authority	Ensures the reliability of the bulk transmission system within its Security Authority Area. This is the highest reliability authority.
	x	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its metered boundary and supports system frequency in real time
		Interchange Authority	Authorizes valid and balanced Interchange Schedules
		Planning Authority	Plans the bulk electric system
		Transmission Service Provider	Provides transmission services to qualified market participants under applicable transmission service agreements
		Transmission Owner	Owns transmission facilities
		Transmission Operator	Operates and maintains the transmission facilities, and executes switching orders
		Distribution Provider	Provides and operates the “wires” between the transmission system and the customer
		Generator	Owns and operates generation unit(s) or runs a market for generation products that performs the functions of supplying energy and Interconnected Operations Services
		Purchasing-Selling Entity	The function of purchasing or selling energy, capacity and all necessary Interconnected Operations Services as required.
		Load-Serving Entity	Secures energy and transmission (and related generation services) to serve the end user

3rd Posting	x	Reliability Authority	Ensures the reliability of the bulk transmission system within its Security Authority Area. This is the highest reliability authority.
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Principles	
Original & 2nd Posting	
x	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions.
x	2. The frequency of interconnected bulk electric systems shall be controlled within defined limits through the balancing of electric supply and demand
	3. Information necessary for planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably
	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented
	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems
	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified and have the responsibility and authority to implement actions
	7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis
Does the proposed Standard comply with all of the following Market Interface Principles? *(Enter 'yes' or 'no')*	yes
1. Interconnected The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy	
2. An Organization Standard shall not give any market participant an unfair competitive advantage	
3. An Organization Standard shall neither mandate nor prohibit any specific market structure	
4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard	
5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards	

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1. Do you agree with retaining the original title? (Industry Responses: Yes 32; No 1; Neutral 2)	
Summary Consideration of Comments: The consensus is agreement with leaving the title alone.	
NERC Interconnected Operations Services Subcommittee (YES)	The IOS Subcommittee agrees with not revising the title. It is sufficiently simple and fits the intent of the standard. Changing "demand" to "load" is too limiting in scope. Use of "requirements" may be technically safe but is overly broad and loses some meaning in describing the focus of the standard - real power balancing.
CA-ISO 2 (NO)	There are several definitions for “demand” in the NERC glossary of terms. The definition of “instantaneous demand”, which I believe we’re talking about here, is “The rate of energy delivered at a given instant”. So then, demand is the measurement of the load, or the rate at which energy is being consumed, not the actual load itself. Another way to look at it is to ask: are we attempting to balance resources with the rate at which the energy is delivered, or the energy usage itself? I believe the answer is that we’re attempting to balance resources with energy usage itself. **Consideration:** *Demand was meant to be BA load plus BA Net Scheduled Interchange. The SDT will include a definition for “demand” in the proposed standard.*

2. Do you agree with the changes that were made to the Purpose? (Industry Reponses: Yes 24 ; No 11)	
Summary Consideration of Comments: The consensus is agreement with the changes that were made but several suggestions were made to delete or clarify the second sentence. The second sentence has been deleted from the revised SAR. Numerous comments recommended specific purposes or needs. The revised *Purpose/Industry Need* either captures the recommendations or the intent of the comments. The SAR has been revised to show that ERCOT expects to have a Regional Difference for one of the measures in this proposed standard (CPM2). WECC expects to have a Regional Difference defining Operating Reserve requirements.	
Allegheny Energy Supply Company (YES)	I do not understand the why the second sentence on the Balancing Authority is required.
Duke Energy Trading and Marketing (Yes)	the term "fair share" is very subjective and could be removed
ERCOT (Yes)	As long as it is recognized that some interconnections have only one Balancing Authority with those responsibilities (second paragraph).
Nebraska Public Power District (Yes)	I did not see the second sentence (about BAs) in the SAR posted on the NERC website. Is it supposed to be there? *The second sentence should have originally appeared in both the SAR and the SAR Comment Form for the second posting of the SAR – however the comments from the industry indicated that the second sentence was unclear and wasn't needed and it is no longer in the SAR..*
We Energies	Define Fair share
California ISO (No)	Please see Yarek Lehr's edits in the Revision Box above
Cinergy - Control Area Operations	I am neutral to the wording of the revised first sentence. The second sentence should be taken out as the purpose should not contain the requirements. A proposed second sentence would be: To set the acceptable control error bounds within which a Balancing Authority must operate to limit negative impact on the Interconnection frequency.
Dominion Virginia Power 2 (No)	Fair Share is too undefined. If included this needs to be much more specific.
Duke Power	The second paragraph refers to the BAs contributing to scheduled frequency, however the BAs do not own

Company (No)	generation so they can not contribute to frequency. The Generator function should be included in this SAR and a performance measure developed (see comment for question #25) to monitor compliance with their submitted schedule and ultimately their contribution to frequency.
Economist (No)	The purpose should be to "limit deviations" from scheduled frequency to within "error bounds" that are just enough to insure against "interconnection failure". "Fair"ness means "FERC approved" and need not be mentioned. Say "range" instead of "profile".
Energy Mark, Inc. (No)	The purpose should be related to preventing the interconnection from experiencing a frequency error condition that will cause interconnection failure. One way of preventing frequency error from reaching unacceptable levels is to operate at a scheduled value and in addition insure that the deviation error from that scheduled value does not reach values large enough to cause an interconnection failure. The revision would be the better of the two choices if the term "profile" was defined to specify the frequency error conditions that will result in interconnection failure. It is not. It has been left undefined. Therefore, the purpose should not be to maintain scheduled frequency, the purpose should be to limit deviations from scheduled frequency to within frequency error bounds that insure reliable interconnection operation. This misdefinition is causing problems with how later decisions are being made.
FRCC (No)	The FRCC OC does not like the second sentence in the revised purpose. BA's contributing fair share seems to be more applicable to the measurement area rather than as a stated purpose.
Illinois Power Company (No)	Illinois Power believes that the purpose must express the specific relationship to reliability. Building off the first sentence of the proposed Purpose IP suggests the following Purpose statement: "Establish meaningful measures that track the performance of Balancing Authorities in maintaining the balance between Demand and Resources so that frequency is maintained within the frequency profile required for reliable system operation." The second sentence of the proposed Purpose statement should be dropped. IP believes that statement does not reflect the purpose, but rather describes a means to accomplish the purpose.
Manitoba Hydro (No)	Manitoba Hydro's main objection to the changes that were made refer to the second line of the revision. We believe that this statement does not belong in the SAR since it defines requirements which could be included in the Standard. The first line of the revised purpose is acceptable.
NERC Interconnected Operations Services Subcommittee (No)	The IOS Subcommittee finds the first sentence of the revision to be acceptable. The second sentence is not acceptable. First, this statement is a weak attempt at a standard, rather than a purpose. Secondly, "fair share" is not defined. The comments described above do not justify adding a concept of "fair share". The purpose of the standard will not be to achieve a "fair share", it will be to maintain frequency within a scheduled profile.

3. Do you agree with the change that was made to eliminate the opening phrase, "Load-resource balance is necessary to . . . "? (Yes 25; No 6; Neutral 4)	
Summary Consideration of Comments: Note: The comments submitted here address the details of the bulleted items rather than the format change addressed by question 3. The consensus of comments did not object to deleting the lead-in phrase. The other comments were evaluated and the intent of the comments incorporated into the *Purpose/Industry Need* language. The SAR DT could not identify a reliability concern with "Time Error in the Interconnection." The SAR DT will ask the industry to identify a reliability issue or concern related to Time Error correction.	
California ISO (Yes)	The third bullet should read "Minimize Time Error in the Interconnection".
CA-ISO 2 (Yes)	The third bullet should read "Minimize Time Error in the Interconnection".
Economist (No)	Arresting "sudden frequency change" must be specified, and that is the exclusive job of Primary Response. "Restoring frequency" so as to maintain it sufficiently within the error bound, must be specified, and that is the exclusive job of Secondary Control, such as Regulation.
Energy Mark, Inc (No)	Resource Demand balance is required to arrest sudden frequency changes caused by resource or demand interruption. This function is performed only by Primary Frequency Control, Frequency Response. If this function is not performed, the interconnection will not get the opportunity to balance resources with demand using other means such as regulation because it will fail before those actions can be applied to correct the imbalance. The purpose of Secondary Frequency Control is to limit normal frequency errors to values such that a sudden frequency change caused by resource or demand interruption is not sufficient to exceed the frequency error limits that bound reliable operations. Therefore, both Primary and Secondary Frequency Control should be addressed by this SAR.

NERC Interconnected Operations Services Subcommittee (No)	The original version is more correct and complete than the revision, although it too is not correct. This process should not result in the level of detail in this SAR being reduced to be comparable with other SARs. It has been expected that this SAR would have more detail early on, since substantial work has already been done in developing concise standards for control performance and disturbance response as part of the NERC compliance program. Eventually all SARs will need more detail. The need statements omit the most obvious and most basic need being addressed by this standard - to maintain frequency within safe limits for the operation of power system equipment and customer equipment. Frequency is ultimately maintained near 60 Hz for one purpose - so generators and other rotating devices don't vibrate themselves to pieces at harmonic frequencies and other frequency-sensitive customer and power system equipment operates properly. In the revision, the first sentence is a repeat of the purpose. The second sentence, to prevent UF load shedding, is marginally valid, but is really a convolution of logic. UF load shedding is installed to retain energized portions of the grid in the event of a major disturbance resulting in a breakup of parts of the system. The purpose of balancing and good frequency control is not to avoid UF load shedding. That is just one constraint that must be observed. If it really was a need being satisfied, 70 Hz would work just fine. The real reasons for good control are a) to protect power system and customer frequency-sensitive equipment and b) to prevent a cascading collapse of the energized grid. These are also reasons that can be generally understood by a broad ballot pool of reliability stakeholders. Everything else is "how". In addition to the two primary justifications of need described in these comments, others that could be included as secondary justifications are: avoid UF load shedding and control time error.

4. Do you agree with deleting Industry Need #1? (Yes 29; No 3 1/2; Neutral 1 ½)	
Summary Consideration of Comments: The comments indicate that the industry agrees with the changes made by the SAR DT. In reviewing the comments submitted, the SAR DT felt that the recommendation of the IOS Subcommittee had significant merit and should be presented to the industry for consideration. The SAR DT will ask the industry to consider this recommended change.	
NERC Interconnected Operations Services Subcommittee (Yes)	The needs statement "arresting sudden frequency changes" could be deleted if replaced by the need of "avoiding a cascading collapse of the interconnected grid". The primary protection from a "sudden" frequency deviation is provided by generator governor frequency response and load characteristic response. The purpose of the fast-acting response to a sudden deviation is to avoid the sudden deviation continuing into a general collapse before the slower acting controls to take over and restore scheduled frequency.
Economist (No)	Arresting "sudden frequency change" must be specified, and that is the exclusive job of Primary Response. Resource demand balancing requires the use of both Primary and Secondary Control. Both must be included in any SAR to address resource demand balancing.
Energy Mark, Inc. (No)	Resource demand balancing requires the use of both Primary and Secondary Control. Both must be included in any SAR to address resource demand balancing.
WECC (No)	I believe balancing resources and demand is required to arrest sudden frequency changes during abnormal conditions. The standard developed from the SAR should include the "arrest frequency" requirement.

5. Do you agree with the modifications made to Industry Need #2? (Yes 27; No 6; Neutral 2)	
Summary Consideration of Comments: The FERC SMD NOPR identifies inadvertent imbalance as a commercial issue rather than a reliability issue. The responses to this question seem inconclusive and the SAR DT couldn't identify a reliabity-related need for Time Error Correction. Given the new information from the SMD and the mixed comments submitted, the SAR DT will ask the industry to identify any reliability-related need for Time Error Correction.	
Manitoba Hydro (Yes)	The emphasis should be that underfrequency will not occur when resources and demand are in balance. An underfrequency load shedding operation should only occur for severe system disturbances where system collapse would most likely occur without the load shedding. Control of frequency would minimize opportunity for operating security limit violations. Would the Standard apply to a system which was isolated from the Interconnection?
NERC Interconnected Operations Services Subcommittee (Yes)	As stated previously in the response to #3, avoiding UF load shedding is a secondary justification and a boundary condition of balancing resources and demand. The primary justifications are for the safety and proper operation of frequency-sensitive power system and customer equipment, as well as to avoid cascading collapse of the interconnected grid. To get the logic straight - UF load shedding is what you do when balancing does not work, it is not the reason you have balancing in the first place. UF load shedding is the backstop or safety net when the balancing does not work, it is not a boundary for "good" control.
WECC (Yes)	The SAR should make clear the requirement to arrest frequency deviations to prevent unwarranted underfrequency load shedding for underfrequency conditions and to mitigate overfrequency conditions in a sufficient time frame and controlled manner to prevent undesirable results.
Dominion Virginia Power 2 (No)	Why does it say "unwarranted load shedding?" Does this mean there is also warranted load shedding? The reference to unwarranted or warranted should be explained more or eliminated. Warranted load shedding is load shedding that is designed to occur in a controlled manner to preserve the integrity of the interconnected electric systems and can be included in commercial contracts such as with large industrial or commercial customers. Unwarranted load shedding is load shedding that is unintended or uncontrolled and is indicative of a failure to meet reliability requirements.
Economist (No)	Frequency error during normal operations needs to be limited only to the extent that, when disturbances do occur, the disturbances do not cause interconnection failure. "Maintaining" frequency sufficiently within the error bound must be specified, and that is the exclusive job of Secondary Control, such as Regulation. This SAR attempts to limit the interconnection's exposure to underfrequency collapse without trying to identify "How".

Energy Mark, Inc. (No)	The real reason to limit the frequency error during normal operations is to insure that the joint probability of normal and disturbance frequency error does not lead to interconnection failure. The joint probability of a frequency error that exceeds the reliability limits can only be determined by considering joint consequences of Primary and Secondary Frequency Control actions. In other words, the starting frequency error value for a disturbance, as determined by Secondary Control, may have as great an influence on the risk of interconnection failure as the size of the change in frequency caused by the disturbance, as determined by Primary Control.
Illinois Power (No)	The first phrase of the proposed need says, with the exception of two words, exactly the same thing as the proposed Purpose. Preventing unwanted underfrequency load shedding is not a need either. It would be a result of meeting this standard. IP also does not believe controlling time error creates a need for this standard. IP proposes that the true need for this standard is to "Avoid extended operation above or below desired frequency (60Hz), at the limits of reliable operation."
Potomac Electric Power Company (No)	Time Error is not a reliability issue. In fact, the correction of time error forces a compensating frequency offset (error). The industry should determine as a commercial issue whether time error should continue to be corrected.

6. Do you agree the SAR should not specifically address over frequency? (Yes 18; No 12; Neutral 5)	
Summary Consideration of Comments: The comments indicate that both under and over frequency are important considerations in this SAR. Although it appears that there are 12 "no's", many of the comments submitted with a "no" indicate a need for overfrequency – the SAR DT feels that the response was mixed because of the 'double negative' included in the question. Please refer to No. 4, Summary Consideration of Comments (above). The SAR was changed to say: Prevent frequency-related cascading collapse of the interconnected grid.	
Allegheny Energy Supply Company (Yes)	Conrol of Frequency implies both under and over.
CA-ISO 2 (Yes)	Balancing addresses both under and over frequency implicitly.
Midwest ISO (Yes)	To be sure my understanding is correct, the Yes vote assumes you mean that there is no need in the standard to differentiate between low and high frequency. Both extremes have reliability impacts. If what you're stating is that there should be no standard for high frequency, this vote should be changed to No.
NERC Interconnected Operations Services Subcommittee (Yes)	Yes, but only if the focus was on protecting equipment and avoiding a cascading collapse - then both over and under frequency conditions would be addressed. Equipment damage or improper operation and cascading collapse could result from an over or under frequency condition. Reference the IOS Subcommittee response to comment #3.
Dominion Virginia Power 2 (No)	From past experience it is apparent that CPM1 and CPM2 are not controlling frequency well. In fact, occurances of over frequency have greatly increased since the adoption of CPS as opposed to operation under the older A1 and A2 standards. It is not clear if this is because the industry has changed or if CPS does not mandate tight control. Although less likely to cause major problems, it is conceivable that if system frequency is very high and a large load trips the result could be very bad. We believe, therefore, that the standard does need to address this.
Duke Power Company (No)	Overfrequency should be addressed.
Duke Energy Trading and Marketing (No)	Overfrequency is also a condition that should be addressed

ECAR (No)	The SAR should specifically address over frequency. The reason we recommend that the SAR address over frequency is that the Eastern Interconnect has a problem during minimum load periods with high frequency. That is why we continue to see fast time during the off peak periods. We believe the reason that this is happening is that companies are not bringing their units to minimum during the off peak period for various reasons. We feel eliminating high frequency from the SAR would be giving tacit approval to continue to allow high frequency operation during the off peak periods.
Economist (No)	Even if the risk of failure due to overfrequency is smaller than the risk of failure due to underfrequency.
Energy Mark, Inc. (No)	The risk of failure due to overfrequency is smaller than the risk of failure due to underfrequency, but it is the joint risk that is of interest. Decisions on reliability should include both the greater risk of underfrequency failure and the lesser risk of overfrequency failure as part of the total risk that must be managed.
Entergy Nuclear Northeast, Inc. (No)	The SAR revised Need #1 (page 4) addresses "Maintain Interconnection scheduled frequency under all conditions...". Doesn't schedule frequency have an upper as well as lower limit. If we want the SAR to only address underfrequency the Need #1 should make that statement.
Michigan Electric Coordinated Systems (No)	Over frequency does have ramifications and needs to be addressed.
Nova Scotia Power Inc (No)	Over frequency results in thermal damage to transformers and generators and is a long term reliability concern.It should be a consideration in the Org Standard.
We Energies	Frequency outside the specified range should be addressed, both over and under.

7. Do you agree the SAR should not eliminate the reference to time error correction? (Yes 21; No 8; Neutral 6)	
Summary Consideration of Comments: The FERC SMD NOPR identifies inadvertent imbalance as a commercial issue rather than a reliability issue. The responses to this question seem inconclusive and the SAR DT couldn't identify a reliabity-related need for Time Error Correction. Given the new information from the SMD and the mixed comments submitted, the SAR DT will ask the industry to identify any reliability-related need for Time Error Correction.	
CA-ISO 2 (Yes)	However, as mentioned before, "Minimize" is more appropriate than "Control".
Duke Power Company (Yes)	Reference to time error should remain.
Duke Energy Trading and Marketing (Yes)	Time error correction is part of good control and its reference should be kept
Economist (Neutral)	Only some customers need it. It is an optional service to customers.
Energy Mark, Inc. (Neutral)	The answer to this question relates to the ongoing value that interconnection time has to our customers. This becomes solely an economic decision.
Midwest ISO (Yes)	Although time error is a secondary measure of interconnection health, it is worth monitoring. Also, nobody knows for sure exactly what would be impacted by releasing the control of time.
NERC Interconnected Ops Services Subcommittee (Yes)	Time error correction is a benefit of controlling the balance of resources and demand, albeit a secondary benefit.
Cinergy - Control Area Operations (No)	I believe more research is needed to determine if time-error accumulation is detrimental to the industry. If economics drives units to run at night and frequency remains at some acceptable level above 60 Hz, is that a problem? Right now the only problem may be trying to correct for it later.
Manitoba Hydro (No)	Time error correction is not viewed as a reliability issue and if required at all should be developed as a separate Standard from this one.
Nebraska Public Power District (No)	Todays clocks are not dependent on frequency. The esxisting use of time error correction lacks technical justification. If there is another reason for this process it should be identified and included in the process with an appropriate name.

8. Do you agree with deleting Industry Need #3? (Yes 29; No 4; Neutral 2)	
Summary Consideration of Comments: There are two other SARs where unscheduled power flows may be addressed: "Determine Facility Ratings, Operating Limits, and Transfer Capabilities" SAR and "Monitor and Assess Short Term Reliability – Operate Within Limits" may both have some components that address unscheduled power flows – one would establish acceptable limits and the other would require operating within those limits. The industry's responses indicate support to delete the respective Industry Need #3.	
California ISO (Yes)	But Transmission Operator should be added as a monitoring entity along with the Reliability Authority in the justification statement
CA-ISO 2 (Yes)	The Transmission Operator or Reliability Authority should be added as a monitoring entity.
ECAR (Yes)	Load-resource balance or imbalance is not the primary cause of operating limit violations and operating limit violations should be part of a SAR on transmission system operation, not a SAR on load resource balance.
Economist (Yes)	Location and transmission-safety limits are not directly a Balancing Authority issue. They are a constraint on and not an objective of the Balancing Authority's actions. Unscheduled flows can be caused by control balancing, not just by imbalance: they can be caused by the Balancing Authority in the normal pursuit of its objectives. Transmission safety limits place a locational constraint on what resources the Balancing Authority can use to balance the system. Transmission safety is the Transmission Operator's function that constrains the Balancing Authority's actions. The Balancing Authority cannot itself exercise this function, determine its own constraints.
Energy Mark, Inc. (Yes)	It is not a Balancing Authority function.
Manitoba Hydro (Yes)	Manitoba Hydro believes that this "Industry Need" is important and could provide reliability benefits by reducing the occurrence of larger amounts of unscheduled power flow. This function belongs in SAR"Monitor and Assess Short Term Transmission Reliability - Operate Within Limits" since the Balancing Authority will not have the appropriate data to accomplish this need.
NERC Interconnected Operations Services Subcommittee (Neutral)	Unscheduled flows can be caused by many factors, one of which can be control imbalances. Preventing unscheduled flows, however, does not itself justify why we need to balance resources and demand - the reasoning is too stretched in this case.
Duke Energy Trading and Marketing (No)	Inadvertent energy is an issue to be addressed by the SAR.
Midwest ISO (No)	Managing unscheduled power flows the primary reason for such a standard, much more so than time error and much more probable then UF load shedding. System separation and potential damage would likely occur

	well before any UF load shedding.

Nebraska Public Power District (No)	Unscheduled power flows caused by inadvertent energy could lead to large unscheduled power flows on flowgates. Since the inadvertent energy is not tagged, there is no way to get it off the flowgate. The TP or flowgate owners won't know where this flow is coming from. Therefore, the balancing standard or some other standard needs to include a requirement to keep unscheduled flows off flowgates.

9. Do you agree with deleting Industry Need #4? (Yes 28 ; No 6; Neutral 1)	
Summary Consideration of Comments: The industry respons indicated support to delete the respective Industry Need #4. The FERC SMD NOPR identifies imbalance as a commercial issue rather than a reliability issue. The SAR DT infers this to mean inadvertent imbalance. If proper control is maintained, a byproduct may be some inadvertent energy, but this does not appear to be a reliabilty issue. NERC expects to participate with NAESB in the development of standards that involve both commercial and reliability components.	
California ISO (Yes)	However, the CAISO feels that Inadvertent Interchange Accumulation between Balancing Authorities and the Interconnection is an important point that needs to be addressed in the Standards process.
Duke Energy Trading and Marketing (Yes)	The NERC JIITF recommended to the NERC RS and NERC OC that the frequency component of inadvertent be addressed by the SAR. CPM1 may already address the issue.
NERC Interconnected Operations Services Subcommittee (Yes)	Inadvertent is an after-the-fact settlement mechanism and provides the least tangible justification for the standard of the reasons in the original version. Inadvertent may be an indicator or measure of performance, but it is not necessarily a good statement of purpose for balancing resources and demand.
We Energies (Yes)	Replace with " allow for reasonable variations in resource control to achieve scheduled frequency"
Duke Power Company (No)	Inadvertent needs to be addressed in one of the 11 proposed standards and this standard appears to be the one that is most appropriate. The word "manage" should be used instead of "minimize".
ECAR (No)	Industry Need #4 should not be deleated. The reason it should remain in the SAR is that one of the primary reasons for balancing load and generation is to make sure that Control Areas do not rely on the Interconnection by importing unscheduled power during periods of high cost power.
Economist (No)	It presumes that FERC can define "inadvertent interchange" well enough to take care of it appropriately in market designs. That contradicts NERC's claim to be the reliability authority because, if not "defined" properly, the product "inadvertent" cannot be priced properly and becomes a reliability issue. If not NERC, then who can define "inadvertent interchange" such that reliability won't suffer? Furthermore, no designs are being planned by FERC for markets between RTOs, only within RTOs, and inadvertent will occur only between RTOs if the RTO becomes the Balancing Authority. So inadvertent interchange risks falling through the cracks or "seams". Need #4 should address "inadvertent", not just "inadvertent accumulations". If not addressed in the "what", inadvertent must be addressed in the "how" since it is an indicator of Balancing Authority performance and impacts frequency performance.

Energy Mark, Inc. (No)	The choice to delete Inadvertent as a reliability consideration can only be made in consideration of how it is managed within the markets. If the resource demand balance components of Inadvertent are managed correctly within the market, then it does not need to be addressed within this SAR. If the reliability components are not addressed adequately within the market design, then reliability will only be able to be maintained by addressing Inadvertent within the SAR.
Michigan Electric Coordinated Systems (No)	Need to retain Need 4 from original version, since no other SAR is addressing Inadvertent.
Midwest ISO (No)	The wording could be improved. The accumulation of inadvertent over the long term is not as significant a concern as the bounding of hourly control. Assuming something close to the existing CPS is implemented, it is possible to have extremely large hourly inadevertents and still get good CPS (as long as accumulations only happen in under 10% of the hours and the accumulations are random with respect to frequency.

10. Do you agree with the changes that were made in making the Brief Description more general, and moving the details to the Detailed Description? (Yes 30; No 2; Neutral 3)	
Summary Consideration of Comments: The industry's responses indicate support for the change that moved the details to the *Detailed Description*.	
Allegheny Energy Supply Company (Yes)	The standard should cover the details.
Duke Power Company (Yes)	As a part of breaking this out into two sections, the Detailed Description section needs to become more specific. In general, Revision 2 of the SAR became more general. The SAR should be more specific.
Economist (Yes)	Say "range" instead of "profile". In the original definition 2 of CPM1 say "relative to" instead of "with respect to".
ERCOT (Yes)	The brief description only is preferred; however, wording changes are needed. In the second sentence, strike "mathematical" and strike "to disperse control responsibility among its entities".These are "hows" and may not fit in a competitive market or single BA environment. Striking these words do not take away from the standard.
NERC Interconnected Operations Services Subcommittee (Neutral)	Now there is very little difference between the brief description and the purpose or need.
Oncor (Yes)	The brief description is preferred; however, wording changes are needed. In the second sentence, strike "mathematical" and strike "to disperse control responsibility among its entities".These are "hows" and may not fit in a competitive market or single BA environment. Striking these words do not take away from the standard.
Illinois Power Company (No)	Illinois Power believes it would be clearer to just have a "Description" section. The introductory paragraph could provide an overview with the details following.
Wisconsin Public Power Inc.	The word 'disburse,' as used in the brief description, is misapplied, as it implies the distribution of funds. 'Assign,' 'allocate' or simply 'distribute' would be more appropriate.

11. Do you think the Brief Description should be revised to include the following: "Balancing Authorities are expected to maintain sufficient resources (i.e., regulation, AGC, Contingency Reserve, DSM, etc.) to stabilize the system following an unexpected event." (or similar language) (Yes 15; No 18; Neutral 2)	
Summary Consideration of Comments: There is no consensus on whether to add these elements to the Brief Description. Half the comments indicated that these elements addressed the "How" not the "What" and the SAR DT agrees with this assessment. Therefore, the suggested change was not made to the SAR.	
CA-ISO 2 (Yes)	Yes, as this is the responsibility of the Balancing authority
Economist (Yes)	Include Frequency Response in the list. Only Frequency Response "stabilizes" the system. The resources listed "restore" the system to normal frequency range after a disturbance, but only once Frequency Response has stabilized the system by containing and ending the disturbance.
Energy Mark, Inc. (Yes)	The resources listed are insufficient to stabilize the system following an unexpected event without Frequency Response.
We Energies (Yes)	Change "unexpected event" to disturbance and define same.
Duke Power Company (Neutral)	AGC does not belong.
Midwest ISO (Neutral)	As long as the description is not too prescriptive, it is fine.
Dominion Virginia Power 2 (No)	It should be revised but with several modifications. We believe the requirement should be more forceful, saying the BA "shall" maintain sufficient resources. Also, we believe the phrase "to stabilize the system following an unexpected event" should be rephrased to stress that the requirement is to prevent the system from slowly progressing into a position where it is easier for an unexpected event to cause problems.
Duke Energy Trading and Marketing (No)	The requirement may be difficult for all BA's to implement given the current structure of the industry.
Entergy Nuclear Northeast, Inc. (No)	This should be incorporated into the Detailed Description.
ERCOT (No)	This is a "How". Keep standards to "What".
FRCC (No)	The FRCC does not believe this belongs in the brief description however, believes this statement should be added as the second sentence introducing the detailed description.
Illinois Power Company (No)	This directly addresses the how, which should not be included in the SAR or the standard.

Manitoba Hydro (No)	The above statement deals with specific details related to a specific operating time increment and does not belong in the "Brief Description" of the SAR.
Mirant Americas Energy Marketing (No)	Don't think this is necessary. The detailed description covers this (referenced measures).
NERC Interconnected Operations Services Subcommittee (No)	This may be stepping into how compliance with the standard is achieved, rather than the standard itself. The desired outcomes are measured by CPM1 and 2 and DCM, not the availability of the resources listed.
Nova Scotia Power Inc (No)	These comments may belong in the Org Std, but are not required in the SAR.
Oncor (No)	This is a "How". Keep standards to "What".
Potomac Electric Power Company (No)	This suggestions is a "How," not a "What."
WECC (No)	Specific requirements should be included in the Detailed Description.

12. Do you agree with the changes that were made in deleting FRM? (26 Yes; 5 No; 4 Neutral)	
Summary Consideration of Comments: The industry's responses affirm the previous posting's support to remove FRM from the SAR. Note: The NERC Resources Subcommittee will assess the technical need for Frequency Response Measure (FRM). If a technical need for this measure exists, a separate SAR addressing FRM may be initiated.	
California ISO (Yes)	At this point in time, the CAISO has very strong concerns regarding the ability to measure FRM in the interconnection.
CA-ISO 2 (Yes)	Measuring FRM and enforcing compliance would be difficult.
WECC (Yes)	It is not clear what FRM is intended to measure or how it is to be measured. It seems somewhat duplicative of CPM1.
WE Energies (Yes)	only as long as "generator goveners and under-frequency load shedding type equipment" requirements are established in the "physical interconnection requirements" standard.
ERCOT (Neutral)	FRM may be an appropriate measure in some cases, but more work needs to be done in its definition.
Duke Energy Trading and Marketing (No)	The recent frequency excursions in the Eastern interconnect demonstrate the need for a frequency response measurement. The SAR committee may want to revisit the effectiveness of the current standard.
Economist (No)	FRM is the most important standard. Without FRM the other standards are ineffective and NERC can close up shop.
Energy Mark, Inc. (No)	The deletion of the FRM Standard demonstrates a significant misunderstanding of how frequency is controlled on an interconnection. Unlimited Secondary Frequency Control resources cannot assure interconnection reliability if there is insufficient Frequency Response to provide the Secondary Control resources the opportunity to respond before interconnection failure. Secondary Control cannot assure reliability without Primary Control.
Midwest ISO (No)	The frequency response of the Interconnections is declining. At some point there will be a reliability problem. The standard does not have to be onerous, but should start to benchmark performance and flag those entities not carrying something close to a reasonable share of their responsibility. It is easy to calculate this performance from the same raw data as the CPM1.
NERC Interconnected Operations Services Subcommittee (No)	Frequency response capability and the measure of frequency response performance is an absolute must for reliability and must be included in a NERC reliability standard. Going back to the underlying basis for balancing, protecting equipment and avoiding a system collapse, frequency response capability is the ability to arrest a sudden, large frequency deviation to prevent a collapse, while slower acting controls can respond. Even if one argues that interconnections are so large that frequency response capability has a diminished value, that is certainly not the case in an islanding condition. Frequency responsiveness has been demonstrated in historical events to enable an islanded system to remain energized during a major disturbance condition.

13. Do you agree with leaving the description of CPM1 intact? (Yes 27; No 6; Neutral 2)	
Summary Consideration of Comments: The last version of the SAR provided clarifying information in a footnote. Based on comments received, the SAR DT refined the footnote and moved the information from the footnote to the body of the text. The industry's comments indicate that most entities want a measure that is the same as or similar to CPS1 (CPM1). The current version of the SAR provides the Standards Drafting Team flexibility to modify the existing CPS1, CPS2 and DCS measures. If the industry wants changes to these existing measures, the changes can be suggested and addressed when the draft standard is posted for public comment.	
FRCC (Yes)	This is part of the new detailed description, not the brief description.
NERC Interconnected Operations Services Subcommittee (Yes)	There is a need to retain the method used in calculating CPM1, but review the expected performance level (e.g. epsilon) for each interconnection based on reliability need.
WECC (Yes)	It should be left as is unless and until someone develops a better measure.
Midwest ISO (Neutral)	Could not see the footnote in the document.
Dominion Virginia Power 2 (No)	A comment on this and the following sections. CPS, CPM, DCS and other measures do not accomplish control in themselves. They simply measure what has happened after the fact. The tools to really match resources to demand are things such as AGC. Currently Policy 1 states that "all units of consequential size shall be equipped for AGC". We believe that this requirement needs to be clearly stated in the detailed description section of the SAR, as well as detailing other mechanisms available to control system frequency. This SAR has received significant indsutry comments indicating that the SAR should address "What", not "How".
Duke Power Company (No)	The last sentence, "Compliance with CPM1…." should be deleted. The measure (e.g. CPM1) is how well the BAs comply with a STANDARD of maintaining the one-minute ACE with respect to interconnection frequency. The intent of CPM1 is to measure how well a BA helps maintain interconnected frequency on schedule.
Economist (No)	The CPM1 frequency range should be based on more than history. It should be derived from some agreed definition of measurable reliability.

Energy Mark, Inc. (No)	The current CPS1 is based upon historic frequency experience. It is not enough to do things the way they have always been done in the past. This opportunity should be taken to consider whether the standard can be directly linked to physical reliability limits that are not based solely on historical experience, or the standard continues to be based on the way things were done in the past. This is a unique opportunity to demonstrate that NERC is a dynamic and changing institution willing to consider new approaches to reliability. The Standards Development Process ensures that all industry participants have an opportunity to identify and present alternate methods for consideration by the industry as a whole. If you are aware of an alternate method for accomplishing what is achieved through CPM1, the SAR DT encourage you to submit this for consideration by the industry during the Standard Drafting stages of this process.
Manitoba Hydro (No)	The proposal to include reference to CPM1 should not be included in item #2 of "Brief Description" because it pre determines that CPM1 will be a measure in the new Standard. The Standard drafting team should be provided the opportunity to investigate alternative methods of defining control performance.
WE Energies (No)	As the industry evolves, the control area will be redifined and managing the balance of resources and load may be done by other means, this measure should not be prescribed based on the historical methods used, doing so now is beyond the scope of this SAR process.

14. Do you agree with leaving the description of CPM2 intact? (Yes 25; No 8; Neutral 1)	
Summary Consideration of Comments: The last version of the SAR provided clarifying information in a footnote. Based on comments received, the SAR DT moved the information from the footnote to the body of the text. The industry's comments indicated that most entities want a measure that is the same as or similar to CPS2 (CPM2). The current version of the SAR provides the Standards Drafting Team flexibility to modify the existing CPS1, CPS2 and DCS measures. If the industry wants changes to these existing measures, the changes can be suggested and addressed when the draft standard is posted for public comment. The revised SAR clearly indicates that ERCOT has a proposed Regional Difference with CMP2 and this has been included in the revised SAR	
FRCC (Yes)	This is part of the new detailed description, not the brief description.
Midwest ISO (Yes)	This assumes the CPM2 remains intact. CPS2 was a safety valve to prevent large flows which could occur within the CPS1 envelope. The standard, if developed, should state whether it applies to single control area interconnections (it would appear moot).
NERC Interconnected Operations Services Subcommittee (Yes)	There is a need to retain the method used in calculating CPM2, but review the expected performance level (e.g. epsilon) for each interconnection based on reliability need.
WECC (Yes)	It should be left as is unless and until someone develops a better measure.
ERCOT (Neutral)	CPM2 would not apply to a single BA Interconnection.
Oncor (No vote completed)	CPM2 would not apply to a single BA Interconnection.
California ISO (No)	As written, the description of CPM2 concentrates on USF and ignores the fact and impact of unintended power flows. The CAISO feels that the description would be more accurate were it to read **"**Control Performance Measure 2 (CPM2) – CPM2[1] measures the Balancing Authority's 10-minute average Area Control Error. Compliance with CPM2 helps minimize unscheduled and/or unintended power exchange between Balancing Authority and Interconnection."
Cinergy (No)	The CPS2/CPM2 limits the number of times a Balancing Authority can impact transmission operating limits with unscheduled power flows, but does nothing to restrict the magnitude of those flows. A Balancing Authority with a 50 MW CPM2 limit, can have an ACE average of -1000 MW for <10% of the measured periods and meet the CPM2. The BA can also score well on CPM1 if frequency averages positive during those times. A new measure should be looked into that will address imbalance when it is detrimental to the scheduled frequency beyond an allowable threshold no matter if it is related to a unit outage, loss of resource, or any other factor.

Duke Power Company (No)	The last sentence, "Compliance with CPM2…." should be deleted. The measure (e.g. CPM2) is how well the BAs comply with a STANDARD of maintaining the ten-minute average ACE.
Exelon	Eliminate “minimize unscheduled power flows” and replace with “control or bound” net interchange (as expressed in the ACE calculation) Use “bound net interchange” in the revised SAR Unscheduled power flows are not a part of this SAR but should be included in the SAR that addresses Operating Limits.
Economist (No)	The CPM2 measure is superseded by the SAR "Monitor and Assess Short-Term Transmission Reliability--Operate within Limits" per question 8 above and the deletion of Need #3. Deleted Need #3 was the justification for CPM2. Furthermore, CPM2 has been scientifically proven [Sasaki & Enomoto, IEEE Transactions on Power Systems, Oct. 2001, pp. 476-81; Sasaki & Enomoto, IEEE Transactions on Power Systems, 2002] to be no better than controlling to ACE alone which has already been replaced by CPS1.
Energy Mark, Inc. (No)	The CPM2 measure is based on the concept of maintaining a historic frequency profile without specifically linking that profile to any reliability objective. It does nothing but maintain history.
Manitoba Hydro (No)	Same comment as in 13 (The proposal to include reference to CPM1 should not be included in item #2 of "Brief Description" because it pre determines that CPM1 will be a measure in the new Standard. The Standard drafting team should be provided the opportunity to investigate alternative methods of defining control performance.)
WE Energies (No)	As the industry evolves, the control area will be redefined and managing the balance of resources and load may be done by other means, this measure should not be prescribed based on historical methods used, doing so now is beyond the scope of this SAR process.

15. Do you think that CPM2 should be changed to be a 60-minute average rather than a 10-minute average? (Yes 2; No 31; Neutral 1)	
Summary Consideration of Comments: The industry comments indicate that the measure should remain at 10 minutes. However, the current version of the SAR provides the Standards Drafting Team flexibility to modify the existing CPS1, CPS2 and DCS measures. If the industry wants changes to these existing measures, the changes can be suggested and addressed when the draft standard is posted for public comment. ERCOT has requested a Regional Difference to the CMP2 measure. The SAR DT endorses the ERCOT request and included ERCOT's exemption from CPM2 in the *Regional Differences* section of the revised SAR..	
Cinergy (Yes)	Possibly. During the development of CPS1, a CPS60 was discussed that would consider both frequency and ACE (unlike the current CPS2) and help achieve the desired frequency performance by having both a 1 minute and 1 hour criteria. I believe this should be looked into further.
Allegheny Energy Supply Company (No)	10 min. allows corrective actions to be taken sooner.
Duke Energy Trading and Marketing (No)	The recent frequency excursions observed in the Eastern Interconnect indicate that CPM2 should not be measured with a longer interval.
Economist (No)	All failures are the consequence of much shorter-interval duration. Only economic/cost advantages have proven [Jaleeli & VanSlyck, Report to EPRI on CPS and IO Procedures, RP-3555-10, Aug. 1996] to derive from a 60-minute measure (of CPS1) because it randomizes control behavior over time and between Control Areas. Economic motives alone are sufficient to prompt participants to control to a 60-minute average within a tighter range than the short-interval average. So NERC need not implement a 60-minute average, even for CPM1. Promoting economic efficiency is not NERC's job but FERC's job, and FERC is supposed to leave economically efficient choices as much as possible to the market participants themselves rather than make them mandatory or build them into market rules, let alone reliability rules.
Energy Mark, Inc. (No)	Before the CPM2 measure is changed to a 60-minute average, it should be demonstrated that there is a reliability risk associated with a 60-minute average frequency control error. There has been no linkage even closely related to interconnection failures resulting from such long-term averages deviations in frequency control. All failures are the consequence of much shorter interval deviations.
Entergy Nuclear Northeast, Inc. (No)	We should identify and correct frequency problems as timely as possible. Large frequency transients which last seconds, which may squew the average, should be addressed as a special case.
ERCOT (No)	CPM2 would not apply to a single BA Interconnection.
Manitoba Hydro (No)	Same comment as in 13 (The proposal to include reference to CPM1 should not be included in item #2 of "Brief Description" because it pre determines that CPM1 will be a measure in the new Standard. The Standard drafting team should be provided the opportunity to investigate alternative methods of defining

	control performance)
Midwest ISO (No)	The No vote assumes you mean to take the average of the 60 one-minute ACE values. Extremely poor performance in the first 30 minutes of an hour could be negated by extremely poor performance in the opposite direction the last 30 minutes. However, if you mean that an hourly CPS1-based metric were used, it could be acceptible.
Michigan Electric Coordinated Systems (No)	The original requirement is a better measure of real time performance.
NERC Interconnected Operations Services Subcommittee (No)	This proposal might be considered in a future revision, but has not been substantiated. Much work has gone into developing the approach using a 10-minute average. Any alternative should be subject to substantial research first.
Nebraska Public Power District (No)	Ten minutes seems more appropriate for monitoring frequency.
Oncor (No Vote Provided)	CPM2 would not apply to a single BA Interconnection.
WECC (No)	In terms of frequency control and inadvertent interchange control, 60 minutes is far too long a period to have any meaning.

16. Do you agree with leaving the description of DCM intact? (Yes 24; No 8; Neutral 2)	
Summary Consideration of Comments: The consensus of the industry responses was to keep DCM. The next posted SAR Comment Form asks the industry for feedback on the unresolved issue of whether there is a need for a standard that fills the time gap between CPS1 (CPM1) and CPS2 (CPM2).	
WECC (Yes)	It should be left as is unless and until someone develops a better measure.
Cinergy (No)	The DCM (if similar to DCS) does not ensure that the Interconnection returns to its scheduled frequency, it ensures that a Balancing Authority's impact on scheduled frequency will be limited to some prefined period (15 minutes) when in a disturbance condition related to a loss of generation or loss of load.
Duke Power Company (No)	The last sentence, "Compliance with DCM…." should be deleted. The measure (e.g. DCM) is how well the BAs comply with a STANDARD of maintaining the ten-minute average ACE.
Economist (No)	Redundant with CPM1. Overkill. The CPM1 Standard already measures disturbance recovery.
Energy Mark, Inc. (No)	The CPM1 Standard also measures disturbance recovery.
Entergy Nuclear Northeast, Inc. (No)	See agree with items 17 and 18 recommendations.
Manitoba Hydro (No)	Same comment as in 13. The present DCM performance measure is insensitive to sytem impact on Interconnection performance which is not ideal. The Standard drafting team should be given free rein to review these criteria and develop what is most appropriate to ensure Interconnection Reliability.
Michigan Electric Coordinated Systems (No)	Adopt language from Question 18.
NERC Interconnected Operations Services Subcommittee (No)	See our comments in 18.
Midwest ISO (Neutral)	There is a need for a standard that fills the time gap between CPS1 and CPS2. The problem is the DCM and DCS are too narrow in scope. The current policy 1 gives about 7 reasons for carrying reserves. They all equate to restoring ACE following an unplanned event. The present DCS just measures a subset of these. There is evidence that some control areas are operating for extended periods with ACE well beyond their reserve requirement but take no immediate action because the deficiciency does not fit the definition of a "reportable event". The way the DCS is crafted, it is acceptible to have a -500 ACE due to failure to commit sufficient resources and wait for a reserve call before deploying 100 Mw of reserves, get back to -400 and pass the standard. ACE is ACE and should be brought back into balance no matter what the cause.

17. Do you think the description of DCM should be changed to include the language, "DCM ensures that the Interconnection helps minimize unscheduled power flows and return its Area Control Error to an acceptable level? (Yes 6; No 27; Neutral 2)	
Summary Consideration of Comments: The consensus of the industry's comments is to leave this language out of the DCM description.	
Cinergy (Yes)	With the addition "..unscheduled power flows due to the sudden unplanned loss of load or generation and . . . ."
California ISO (No)	USF, associated with DCM, would be a secondary consideration and should be addressed in a SAR relating to Transmission Operators.
CA-ISO 2 (No)	DCM is to insure that the Balancing Authority maintains reliability above reducing USF or inadvertent.
Dominion Virginia Power 2 (No)	As stated above, these measures do not ensure power flows will be balanced. They are simply measures of other system controls which may or may not result in correct actions.
Economist (No)	Unscheduled power flows are not "minimized". They are "optimized" according to a pricing mechanism that incents participants to keep frequency on average within a NERC-established reliability range. Move the word "help" from "helps minimize" to "helps ensure" so that the proposed change reads: "DCM helps ensure that the Interconnection minimizes unscheduled power flows and returns its Area Control Error to an acceptable level"
Energy Mark, Inc. (No)	Before including the minimization of unscheduled power flows as a reliability instead of an economic problem, it must be demonstrated that unscheduled power flows are a reliability problem and the Balancing Authority is the proper participant to address the problem.
Midwest ISO (No)	Is the proposed wording correct? How would a DCM cause an INTERCONNECTION to help minimimize its ACE and unscheduled flow? Do you mean Control Area, if so, the vote can be changed to yes.
NERC Interconnected Operations Services Subcommittee (No)	See our comments in 18.
Nova Scotia Power Inc (No)	Wording in the posting is ok.
Oncor (No)	CPM2 would not apply to a single BA Interconnection.
Potomac Electric Power Company (No)	The "Interconnection" does not have an Area Control Error.
WECC (No)	DCM is not about what the Interconnection can do, but what the Balancing Authority must do.

WE Energies (No)	The "minimize unscheduled power flows" implies a schedule??? We don't know what that is yet!! and is beyond the stated industry need.

18. Do you think the description of DCM should be changed to include the language: "DCM ensures that the deficient system returns to an acceptable balance level within a defined period, following a sudden generation or load change. " (Yes 16; No 13; Neutral 6)	
Summary Consideration of Comments: The industry's responses did not indicate consensus on the need for this change. The SAR DT discussed the various recommendations and drafted language to be more technically specific. This revised DCM language included in the latest version of the SAR states: DCM requires that the deficient BA return to an acceptable balance level within a defined period, following a sudden generation or load change. This measure requires the responsible Balancing Authority to quickly return its Area Control Error to an acceptable level.	
Cinergy (Yes)	With the wording change "..following a sudden unplanned loss of generation or load. . ." I believe the wording should also reflect that the DCM ensures that a Balancing Authority's impact on scheduled frequency will be limited to some window (15 minutes) when in a disturbance condition related to a loss of generation or loss of load.
Duke Power Company (Yes)	The first sentence "DCM ensures that the Interconnection…." should be replaced with the sentence from above "DCM ensures that the deficient system…."
NERC Interconnected Operations Services Subcommittee (Yes)	This description is the most accurate, except that DCM does not "ensure" anything - it tells someone how well they performed. DCS measures the effectiveness of a deficient system in returning to an acceptable balance within a defined period. This statement is preferable to 16, 17 or 19.
Midwest ISO (Neutral)	See the earlier comments that this definition appears to be too narrow. There are other things that cause a large ACE value that should be corrected.
Nova Scotia Power Inc (No)	Wording in the posting is ok.
Oncor (No)	CPM2 would not apply to a single BA Interconnection.
WECC (Yes)	This description more clearly indicates who is responsible.
WE Energies (No)	Already stated in the 2nd sentence of the origional.

19. Do you think that DCM should be dropped because it isn't linked to a frequency profile and can't be easily measured? (Yes 4; No 31)	
Summary Consideration of Comments: The industry's responses indicate that DCM should not be dropped from this SAR. However, the current version of the SAR provides the Standards Drafting Team flexibility to modify the existing CPS1, CPS2 and DCS measures. If the industry wants changes to these existing measures, the changes can be suggested and addressed when the draft standard is posted for public comment.	
Allegheny Energy Supply Company (No)	DCM is needed to protect generation equipment from damage during a disturbance.
Cinergy (No)	I stated "NO" only because I believe we need a standard that will drive a Balancing Authority to take corrective action in real time, whenever its operations are impacting the scheduled frequency beyond some pre-defined bounds in consideration of ACE and frequency. The DCM is the closest criteria we have for requiring corrective action when imbalance is impacting the Interconnection.
Entergy Nuclear Northeast, Inc. (No)	Agree with items 17 and 18.
Manitoba Hydro (Yes)	DCM is not an analytical measure of performance and not sensitive to the impact that the disturbance has on the Interconnection. An attempt should be made to develop a DCM which accounts for the impact of the disturbance on the Interconnection frequency performance. It is possible that CPM1 and CPM2 could be modified in such a way to eliminate the need for DCM altogether.
Midwest ISO (No)	Your premise is incorrect. A large ACE does impact the frequency profile and is not that difficult to measure via an hourly CPS metric.
NERC Interconnected Operations Services Subcommittee (No)	DCM is an important element of bounding the balancing of resources and demand.
WECC (No)	DCS is "easily measured." There is no reason to think DCM will be any more difficult.

20. Do you agree this SAR should only have functions for the Balancing Authority? If you think other functions should have performance measures, please identify those measures and their associated functions in the comments. (Yes 24; No 7; Neutral 4)	
Summary Consideration of Comments: This SAR, as originally written, addressed functions that apply just to the BA. Based on the industry's comments, the description has been revised to include the Reliability Authority's (RA) oversight of this function. The following additions were made to support the addition of the RA function: – Added to the Brief Description: The RA needs to have the authority to direct actions (to control frequency) that include load shedding. – Added to the Detailed Description: The Standard requires that the RA monitor system frequency and BA activities and direct action when the RA determines that the interconnected electric system is at risk. For all other functions, the SAR DT are unsure if there will be measures and compliance elements beyond those identified for the BA and the RA. Additional functions may be identified as the standard is developed.	
Duke Energy Trading and Marketing (Yes)	Frequency and AGC effectiveness should also be measured. The functions in this section of the SAR are the functions defined in the Functional Model. (Reliability Authority, Balancing Authority, Interchange Authority, Planning Authority, Transmission Service Provider, Transmission Owner, Transmission Operator, Load Serving Entity, Distribution Provider, Purchasing Selling Entity and Generator)
Economist (Yes)	Other SARs should address the means to provide the Balancing Authority with the necessary resources to meet the requirements of this SAR.
Energy Mark, Inc. (Yes)	Other SARs should address the requirements to provide the Balancing Authority with the necessary resources to meet the requirements of this SAR.
ERCOT (Yes)	Better to keep this focused at this level for now. However it is important to develop additional standards involving provision of ancillary services, as these may be provided by generators, scheduling entities, and marketers not part of the balancing authorities organization.
Nebraska Public Power District (Yes)	It is th BA's responsibility to have the appropriate arrangements in place to satisfy the requirements of this SAR.
WE Energies (Yes)	Need to recognize interdependency of other functions. This gets to the heart of Who has the obligations and responsibilities for the "energy adequacy" of the system. I do not believe this is agreed upon in the industry. The Provider of Last Resort for serving load shall be ultimately responsible although may deligete to a service entity to carry out, or must be able to perform the function itself.

Midwest ISO (Neutral)	We agree that the BA has the primary responsibility and should be held to some standard. Since CPM and the other standards are the ultimate desired outcome, generators (or loads) self-providing or selling ancillary services (or IOS) should be held to similar standards.
California ISO (No)	The Balancing Authority plays an integral role in responding to the requests of and working in cooperation with the Transmission Operators, Reliability Authority, and Interchange Authority and as such, reference or linkage to these cannot be eliminated.
CA-ISO 2 (No)	The Balancing Authority plays an integral role in responding to the requests of and working in cooperation with the Transmission Operators, Reliability Authority, and Interchange Authority and as such, reference or linkage to these cannot be eliminated.
Duke Power Company (No)	Apply to Generator, LSE, PSE functions. These functions need to have a requirement to meet the schedules given to the BAs, either in this standard or another. The performance measures- for compliance with the standard- for these functions would need to be developed and clearly defined. These performance measures should be stated in this or the applicable standard.
Manitoba Hydro (No)	This SAR should have functions for the Reliability Authority as well as the Balancing Authority since the Reliability is the highest level Authority and has responsibility for implementing transmission loading relief procedures which may impact Balancing Authority function. The Reliability Authority should be aware of any network balancing issues in the Balancing Authorities within its footprint of responsibility so if problems arise in one Balancing Authority another Balancing Authority can help the one in trouble if required for interconnection reliability. An example of this type of function is the Reserve Sharing Pool where several balancing Authorities share their operating and spinning reserves.

Michigan Electric Coordinated Systems (No)	In Michigan SAR would apply to IA, Generators and PSE. CPS1, CPS2 and DCS sanctions/penalties would be allocated to the entities performing these functions. Michigan structure needs to be allowed for in SAR. The Functional Model assigns tasks to specific "functions". The functional titles used in the Functional Model may or may not match the titles used by any single entity. At some time in the future, there will be a process whereby each entity will register with NERC and identify the "functions" it wants to be recognized as performing. From NERC's perspective, the "functions" in the Functional Model are the functions for which the industry ist developing standards. Thus, whatever an entity's structure, if that entity registers to perform the "balancing authority " tasks, that entity will be considered the Balancing Authority and will be expected to comply with all sections of all standards that are developed for the BA. Note that an entity may perform more than one function. While this SAR currently indicates that there needs to be measures such as CPM1, CPM2 and DCM, the industry has an opportunity to review and comment on the appropriateness of these measures. The determination of appropriate compliance for each measure will be accomplished during the Standard Drafting stage of this process. All compliance elements will be publicly posted and will be revised so they represent what the industry wants. There is, therefore, no guarantee that the compliance currently in effect for CPS1, CPS2 and DCS will be the compliance elements associated with the proposed standard.
NERC Interconnected Operations Services Subcommittee (No)	Omitting the requirement that all generators, loads, and transmission facilities must be metered into one and only one balancing area results in a standard that is incomplete and doomed to failure. As a simple case, generators could serve loads, while synchonized to the grid, without being part of a balancing area. The functional model breaks down if all energized facilities are not part of a balancing area. This most basic requirement cannot be left to regulations, contracts, or other forms of rules for generators and loads. This statement is in the current Operating Policy 1, and along with the BA's obligation to balance resources and demand to meet CPM1, CPM2, DCM, and FRM, this statement is a cornerstone of the proposed new standard: "All load, generation, and transmission operating in an Interconnection must be included within the metered boundaries of a Control Area". This comment was submitted in the first posting of the SAR and appears to be lost in the analysis provided above. Furthermore, the IOS Subcommittee, as documented in the IOS Reference Document, believes that IOS Supplies have specific obligations associated with real-time balancing. To the extent that balancing obligations apply to IOS Suppliers, the applicable functions should be checked. For example, the definitions shown in the table indicate that generators and PSEs may have IOS responsibilities. Certification requirements for the BA are expected to contain language that includes requirements for metered boundaries and authority within those bounaries.

WECC (No)	Reliability Coordinator should have oversight authority. Planning authority should have responsibility to plan the system to comply with the resource/demand balancing requirements. The other functions (generator, load serving entity, transmission provider, etc.) have a secondary responsibility to help ensure that compliance with the resource/demand balancing requirements is achieved.

21. Do you agree with leaving the Reliability Principles as originally identified? (Yes 18; No 10; Neutral 5)	
Summary Consideration of Comments: There is no consensus on whether to change the Reliability Principles. The reliability principles can be interpreted broadly or narrowly and no single interpretation seems to have more technical merit than another. The SAR DT added all recommended principles to the revised SAR.	
NERC Interconnected Operations Services Subcommittee (Yes)	Yes, only one box is required and # 2 works the best.
Duke Energy Trading and Marketing (No Vote Provided)	Our version of the SAR had no boxes checked and therefore we agree or disagree.
California ISO (No)	Please see response to Question #22, below.
CA-ISO 2 (No)	Please see response to Question #22, below.
Manitoba Hydro (No)	Manitoba Hydro believes that Reliability Principle #7 should be added to the applicable Principles because resource and demand balance can have a significant impact on the reliability of the Interconnection.
Nova Scotia Power Inc (No)	# 3 should be added
WE Energies (No)	I believe all 7 Reliability Principles apply to the function of a BA and are needed to meet this standard as the primary role of the BA.

22. Do you agree Reliability Principles #3 and #5 should be added to this SAR? (Yes 14; No 13; Neutral 7)	
Summary Consideration of Comments: There is no consensus on whether to change the Reliability Principles. The reliability principles can be interpreted broadly or narrowly and no single interpretation seems to have more technical merit than another. The SAR DT added all recommended principles to the revised SAR.	
California ISO (Yes)	The CAISO also feels that Reliability Principles #' 4 & 6 are applicable in this SAR.
CA-ISO 2 (Yes)	Reliability Principles #' 4 & 6 are applicable in this SAR.
Duke Power Company (Yes)	Reliability Principle #6 should be added also.
Duke Energy Trading and Marketing (No vote provided)	Our response depends on the application of the SAR. If the SAR is to apply to both RA and BA, would agree.
Entergy Nuclear Northeast, Inc. (No)	Agree with item 21.
ERCOT (No)	These belong in other SAR's, but they are still important. Hopefully we will develop some means to link or at least cross-reference these situations.
Michigan Electric Coordinated Systems (Yes)	Also add Principle 6
Nova Scotia Power Inc (No)	add #3 only
WECC (Yes)	I believe all the reliability principles apply.

23. Do you agree the SAR should be revised to incorporate these objectives? {Yes 7 and 3 yes votes for the first half of this question; No 18 and three no votes for the second half of this question; Neutral 7)	
Summary Consideration of Comments: There is not industry consensus to change the SAR to include this language.	
Allegheny Energy Supply Company (Yes)	In addition, limit dip to insure generation equipment is protected from damage.
WECC (Yes)	If UFS is underfrequency load shedding, I agree to the extent that it should not cause unwarranted underfrequency load shedding. I am not sure of the intent of the second comment, but it should be covered by DCM if it's referring to the period following a disturbance.
Economist (Yes/No)	Yes to the first. No to the second.
Energy Mark, Inc. (Yes/No)	I agree with the first, I do not agree with the second.
National Grid USA (Neutral)	IF no other industry standard explicitly states frequency limits where ALL balancing authorities will initiate some form of corrective action, then we believe that industry limits should be include in this document for they are essential in returning the interconnection to normal.
Duke Power Company (No)	Should not be revised.
Duke Energy Trading and Marketing (No)	Underfrequency is addressed in the Industry Need for standard issue. See comment for 25.
Manitoba Hydro (No)	There are many systems where it would be impossible to implement performance requirements related to item 1. In many systems underfrequency load shedding is implemented as the least cost solution to ensure that the underfrequency is minimized to a level where a system blackout does not occur. The second bullet is a desirable objective which all systems should try to get to within the practical limits of money and resources.
Midwest ISO (No)	The No vote is because two different objectives were bundled. The UF load shedding is may already be included depending on the votes to earlier questions. We agree that this is important, but again, two objectives were bundled. The"specied time" assumes a DCS-like standard.

24. Do you agree the SAR should be revised to include checking control error? (Yes 9; No 21; Neutral 6)	
Summary Consideration of Comments: There is not industry consensus to include this change in the SAR.	
Cinergy (Yes)	As long as the components of each can be compared to determine if the error between real-time and ATF was due to metering, scheduling, control, and so on.
Economist (Yes)	This can eliminate inadvertent resulting from incorrect metering.
Energy Mark, Inc. (Yes)	The above should end ….inadvertent developed due to incorrect metering.
Midwest ISO (Yes)	The standard is meaningless if ACE is misstated.
Wisconsin Public Power Inc. (Yes)	In addition, the standard should be expanded so as to prevent individual Balancing Authorities from 'leaning on the interconnection' by operating with significant positive values of Area Control Error during periods of when this poses difficulty for neighboring Balancing Authorities. This is a matter of reliability, and the existing Control Performance Standards are not adequate to achieve this result.
WE Energies (Neutral)	Need to account for adequate metering and communication ckts in the interconnection standard, this standard may or yet another new SAR may establish the "maintenance" requirements. This should be addressed in the Certification Requirements for these Functions.
Duke Power Company (No)	Should not be revised.
Duke Energy Trading and Marketing (No)	Should already be reflected in the CPM standards.
ERCOT (No)	This may belong in another SAR that covers control and data collection systems
Manitoba Hydro (No)	It was unclear what this comment was intended to address.
NERC Interconnected Operations Services Subcommittee (No)	Some would argue inadvertent is a reliability issue and others would say it's a settlement issue if you have the other performance measures in place. There should be an explicit justification of why checking control error is necessary for reliability if it is to be included. The JIITF had a good concept - what is really needed for reliability is a continuous feedback loop to incent good performance in real time, not an after-the-fact settlment method.
Potomac Electric Power Company (No)	Inadvertent interchange, while a measure of control performance, is a commercial issue.

WECC (No)	I believe "checking" of control error is inherent in CPM 1 & 2. Details such as checking average interchange against metered interchange are a matter of self-interest on the part of the BA because inadvertent must be tracked and repaid to the Interconnection.

25. Do you agree the standard should include a more quantifiable definition of the term, "disturbance?" (Yes 13; No 18; Neutral 4)	
Summary Consideration of Comments: There is no consensus to modify the SAR to include this definition. The Standards Drafting Team will have responsibility for defining terms used in the proposed standard.	
Nebraska Public Power District (Yes)	The standard should include a definition of a disturbance for reporting purposes. The SAR does not need this definition.
WECC (Yes)	It could include a specific magnitude of frequency deviation that may necessarily be specific to each Interconnection.
Midwest ISO (Neutral)	If you have a DCS-like standard, there would have to be some objective way of knowing what constitues a measureable event. As noted earlier, ACE should be maintained within some general bounds, no matter what the cause.
Mirant Americas Energy Marketing (Neutral)	The term "disturbance" should be better defined (more specific). However, this need not be done in this standard. Could be part of NERC standards glossary.
Duke Energy Trading and Marketing (No)	Disturbance may be difficult to quantify – but the operator ought to recognize one when it occurs. That is why we support having trained professionals operate the system.
FRCC (No)	However, the FRCC OC believes the standard drafting team will need to be clear when DCM applies when they are drafting the words for the standard itself.
Illinois Power (No)	The SAR should not include detailed definitions. This should be left to the development of the standard
NERC Interconnected Operations Services Subcommittee (No)	There exists today in the NERC vernacular no less than three definitions of "disturbance". Adding another is not going to help. What should be done is a SAR should be submitted to form a single NERC Glossary that goes through the consensus process and is maintained to support the other standards.
WE Energies (No)	Develop a Glossary of Terms applicable to all standards.

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**B**HE 2400 AST Monday through Saturday to HE 0800**B**HE 2300 AST Monday through Saturday. Similarly, the off-peak hours change from HE 0100**B**HE 0800 AST Monday through Saturday to HE 2400**B**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**B**HE 2300 EST Monday through Saturday to HE 0700**B**HE 2200 EST Monday through Saturday. Similarly, the off-peak hours change from HE 2400**B**HE 0700 EST Monday through Saturday to HE 2300**B**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**B**HE 2200 CST Monday through Saturday to HE 0600**B**HE 2100 CST Monday through Saturday. Similarly, the off-peak hours change from HE 2300**B**HE 0600 CST Monday through Saturday to HE 2200**B**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**B**HE 2400 CST Monday through Saturday to HE 0800**B**HE 2300 CST Monday through Saturday. Similarly, the off-peak hours change from HE 0100**B**HE 0800 CST Monday through Saturday to HE 2400**B**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**B**HE 2300 MST Monday through Saturday to HE 0700**B**HE 2200 MST Monday through Saturday. Similarly, the off-peak hours change from HE 2400**B**HE 0700 MST Monday through Saturday to HE 2300**B**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**B**HE 2200 PST Monday through Saturday to HE 0600**B**HE 2100 PST Monday through Saturday. Similarly, the off-peak hours change from HE 2300**B**HE 0600 PST Monday through Saturday to HE 2200**B**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 B The Area Control Error Equation, Section B 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	

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

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

Recommendations for the Wholesale Electric Industry of North America:

Inadvertent Interchange

Draft 5d

May 10, 2002

A White Paper Prepared by the

Joint Inadvertent Interchange Task Force

For Consideration by the:

Resources Subcommittee

Market Interface Committee

Compliance Committee

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

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

May 10, 2002

Carl A. Monroe
Chairman, Resources Subcommittee
Southwest Power Pool
415 North McKinley
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Little Rock, Arkansas 72205

Joint Inadvertent Interchange Task Force (JIITF) White Paper, Recommendations for the Wholesale Electric Industry of North America: *Inadvertent Interchange*, Draft 5d

Dear Carl:

The Joint Inadvertent Interchange Task Force has almost completed it assignments, and would now like to present its conclusions and recommendations to the Resources Subcommittee and Operating Committee.

The JIITF has formalized its Conclusions to the Operating Committee as follows:

JIITF Recommendation for Action

The JIITF broke down the current NERC definition of Inadvertent Interchange into three "Unscheduled Energy" components: a Frequency Component; a Line Loading Component; and an Energy Component. The Task Force recommends the Frequency Component and the Line Loading Components be addressed in NERC Organization Standards. The JIITF believes the Energy Component is actually a business practice and should be handled by some other organization.

The JIITF composed the following statements addressing each of the three unscheduled energy components and the future of the JIITF:

Frequency Component: The frequency component of unscheduled energy interacts with the "Balancing Resources and Demand" SAR. The JIITF will contribute its White Paper, "Recommendations for the Wholesale Electric Industry of North America: *Inadvertent Interchange*" to the Resources Subcommittee. The Resources Subcommittee can then provide the white paper as a reference document to aid the SAR drafting team and future standard drafting team efforts.

Line Loading Component: The Transmission Loading Component of unscheduled energy interacts with the "Monitor and Assess Short-term Transmission Reliability – Operate Within Limits" SAR. The JIITF believes any congestion management standard developed under this SAR must apply to both scheduled and unscheduled energy into or out of Balancing Authorities. The JIITF will convey this belief to the Requestor of this SAR.

Energy Component: The settlement of the "energy component" of unscheduled energy is considered a business practice and should be addressed by an organization developing business practice standards.

"Allow for reasonable variations in generation control" and "Encourage minimizing imbalances due to poor control"

The JIITF believes properly addressing the "Frequency Component" of unscheduled energy the "Balancing Resources and Demand" SAR will incorporate allowances for reasonable variations in

generation control and encourage minimizing imbalances due to poor control. This depends, of course, on proper treatment of the Energy and Line Loading components in their respective processes.

JIITF Future: The JIITF has addressed the issues and concerns of the OC regarding Inadvertent Interchange. The future of the JIITF is at the pleasure of the OC (i.e. disband, assign additional Inadvertent Interchange issues and concerns, etc.). The recommendation of the JIITF is to disband. The members of the JIITF are from the Resources Subcommittee, the Market Interface Practices Subcommittee, the Compliance Subcommittee and the Electric Energy Industry. These individuals are available to participate, on an individual basis, in the development of the NERC Organizational Standards. The Task Force membership is listed in Attachment A.

The JIITF concepts were presented to the Operating Committee, the Market Interface Committee and the Planning Committee at their March 19–21, 2002 meetings. Based on the Committees' responses as well as industry comments, the JIITF re-evaluated the JIITF concepts in determining the above conclusion statements. The JIITF will not spend time reworking the White Paper, since it will remain in "Draft" form and be used as a reference document. (See Frequency Component Conclusion, above.)

The JIITF White Paper, Draft 5c, dated March 7, 2002, will remain intact as it was on that date. However, this letter will be inserted in front of the Executive Summary, creating Draft 5d, dated April 18, 2002.

Conclusion

Given the changed environment for standards development, the JIITF recommends each of the three elements of "Unscheduled Energy" be addressed by other groups within the new process. The JIITF

reiterates its position that comprehensive treatment of the issue must include addressing all three components: Frequency, Line Loading, and Energy. The JIITF offers its draft white-paper, as a reference document, to the Resources Subcommittee for consideration in the SAR development process.

Sincerely,

Paul Spicer

Paul Spicer
Chairman, Joint Inadvertent Interchange Task Force

PS:TJV:mjh

cc: Joint Inadvertent Interchange Task Force
Resources Subcommittee
Market Interface Practices Subcommittee
Compliance Subcommittee

Attachment A

Joint Inadvertent Interchange Task Force Membership		
Name	**Representation**	**Company**
Paul Spicer, JIITF Chairman	Resources Subcommittee	Wisconsin Public Service
Carl Monroe	Resources Subcommittee	South West Power Pool
Mike Potishnak	Resources Subcommittee	ISO New England
Terry Bilke	Resources Subcommittee	MISO
Don Badley	Resources Subcommittee	WSCC
Tony Jankowski	Market Interface Practices Subcommittee (MIPS)	Wisconsin Electric Power
Jon Puckett	MIPS	Duke Energy North America
Dean Ulch	MIPS	Southern Company Services
Shirley Buckmier	MIPS	BPA
Peg Appadini	MIPS	Central Illinois Light Co.
Chris Jones	MIPS	Reliant Energy HL&P
Gary Rudder	Compliance Subcommittee	Tennessee Valley Authority
Joe Wilson	Compliance Subcommittee	PJM
Howard Illian	Electrical Industry Participant	Energy Mark Inc.
Warren McReynolds	Electrical Industry Participant	WSCC
Robert Blohm	Electrical Industry Participant	Economist
Tom Vandervort	JIITF Facilitator	NERC

Inadvertent Interchange

Joint Inadvertent Interchange Task Force

Executive Summary

The Joint Inadvertent Interchange Task Force (JIITF) is a joint effort of the OC Resources Subcommittee, MIC Market Interface Practices Subcommittee, the Compliance Subcommittee and commercial power industry experts to address and develop recommendations for Inadvertent Interchange Operating Standards.

This paper addresses Inadvertent Interchange as it relates to interconnection reliability. The JIITF realizes Inadvertent is the result of good and poor control practices, built-in accounting anomalies, and is a necessary result of Interconnected operation in a synchronous multi-Balancing Authority network. The proposed solutions attempt to appropriately hold accountable those Balancing Authorities exhibiting poor control practices and recognize those exhibiting good control practices.

Transmission Control aspects of reliability are discussed and remain to be addressed locally, while Interconnection frequency aspects of reliability are addressed specifically. Inadvertent, the difference between a Balancing Authority's scheduled and actual hourly Net Interchange, is defined in Policy 1.

The proposed JIITF solution to the OC charge is three-fold: 1) A transmission use component of existing Inadvertent Interchange is recommended to be included in any congestion management standard developed to be consistent with local transmission market designs; 2) A frequency control component of existing Inadvertent Interchange is recommended to be a stand-alone standard, treated as an obligatory reliability service; and 3) An energy component of existing inadvertent Interchange is recommended to be a stand-alone standard, treated as a commodity. The markets will value Inadvertent energy pay-back and influence settlement practices.

The Reliability Principles, Market Interface Principles, and the JIITF Inadvertent Interchange Principles are found in Attachment 1. The JIITF used these principles for guidance to follow and as defining parameters to stay within in order to meet the requirements of the NERC Standards Authorization Process Manual.

While a Balancing Authority's hourly Inadvertent Interchange is desired to average to zero, it is unrealistic to expect it to be zero at all points in time. The JIITF identified five major causes of Inadvertent Interchange: 1) Scheduling Error, 2) Meter Error, 3) Unintentional Control Error, 4) Ramping Representation Error and 5) Intentional Control Adjustment. An expanded list is found in Attachment 2.

The JIITF proposed "Transmission Loading/Obligatory Reliability Service Local Standard" is discussed in Attachment 3.

The JIITF proposed "Frequency Control/Obligatory Reliability Service Operating Standard" is found in Attachment 4.

The JIITF proposed "Inadvertent Interchange Operating Standard" is found in Attachment 5.

An option to control (in the short run) existing Inadvertent Interchange accumulation using "100 times L60" is found in Attachment 6

The impact of the Proposed JIITF Solutions on Time Error Correction is found in Attachment 7.

Data Validation and Dispute Resolution process for the Inadvertent Interchange Operating Standard is summarized in Attachment 8.

Operating Committee Action

The Operating Committee approved the following Control Area Criteria Task Force (CACTF) recommendation:

> The Resources Subcommittee, along with the Compliance Subcommittee, and a Subcommittee to be named by the MIC, develop Control Area (and Balancing Authority) Inadvertent Interchange Operating Standards including market incentives and penalties that provide for the following two requirements:
>
> - Allow for reasonable variations in generation control, and
>
> - Encourage minimizing imbalances due to poor control.

Commercial Advantages

The emergence of regional power markets in recent years has created new challenges for the operation of the interconnected power system not anticipated in current NERC Policies and Standards. The CACTF identified a practice in the NERC Operating Policies that appears to afford a Balancing Authority's affiliated generators and marketers a commercial advantage over their independent counterparts. This practice is the use of Inadvertent Interchange by Balancing Authorities vs. Energy Imbalance compensation by non-control areas.

Inadvertent Interchange versus Energy Imbalance

The commercial advantage a "traditional" Balancing Authority with affiliated generation has over an independent generator is the method for settling energy imbalances. Specifically, the Balancing Authority satisfies NERC inadvertent rules by repaying with in-kind energy (On- or Off-Peak) at its discretion, while an independent generator (non-Control Area) repays imbalance in accordance with the host Balancing Authority's contract; possibly at market prices.

Inadvertent interchange is the difference between a Balancing Authority's Net Actual Interchange and Net Scheduled Interchange each hour. It includes moment-to-moment control action to continuously support frequency and adjust its real-time generation-to-load balance (Net Actual interchange) with its intent to import/export energy to meet its contractual obligations (Net Scheduled Interchange). The resulting "Inadvertent Interchange" at the end of the hour is owed to or from other Balancing Authorities in the Interconnection. NERC Operating Policies (Policy 1, "Generation Control and Performance") require that Balancing Authorities settle within the Interconnection for this imbalance; generally, with energy or, if permitted by the Interconnection, in financial terms. While NERC requires that Balancing Authorities meet specific Control Performance Standards, there are no requirements on how much Inadvertent Interchange can be accumulated, when it must be settled, or how that settlement must be priced.

Before market-based energy rates were allowed, reconciliation of Inadvertent Interchange with energy only was considered to be an equitable one-for-one settlement methodology. Cost-based energy prices, allowed at the time, were not volatile. Ten years ago the marketplace did not see energy prices in the $100+ range. Also, there was a general understanding that Balancing Authorities were on both sides of the inadvertent balance, sometimes long, sometimes short. Today, when energy prices become very high, a Balancing Authority can "lean" on the Interconnection and accrue an inadvertent balance. The respective Balancing Authority can hen repay that balance with energy days, months, or years later when energy prices are lower.

Energy imbalance charges. Energy Imbalance Service is the difference between the intended delivery and the actual averaged delivery of energy, by an independent generator, to a load located within a "host" Balancing Authority each hour. The host Balancing Authority must continuously adjust its generation on a moment-to-moment basis to make up the imbalance to meet NERC's Control Performance Standards obligations. Balancing Authorities' connection tariffs usually require that this Energy Imbalance be financially settled at market rates.

Comparison Arguments. By definition, Balancing Authorities' Inadvertent Interchange cannot be equally compared to Independent Generators' Energy Imbalance. However, the settlement of the Inadvertent energy component and the Energy Imbalance could be made to be comparable.

Balancing Authorities are required to continuously balance generation against schedules, taking into account generation-to-load ramping, constantly changing demand, generation variation, Interconnection frequency deviations, and NERC Control Performance Standards obligations. Independent generators, on the other hand, usually follow an energy profile that may or may not change hourly. Some independent generators sell load-following or control services, that result in fluctuations of their generators' output.

The Energy Imbalance Service (Schedule 4 in the *pro forma* Tariff) meets the objectives by applying penalties and credits for energy imbalance. It allows for a "deviation band" of ± 1.5% and sets standards for repayment via energy (within the deviation band) within 30 days. If repayment in energy has not occurred in a "reasonable" time, then repayment is in financial terms, which could be at market rates. This both discourages large imbalances and compensates the host Balancing Authority for providing the energy to mitigate the imbalance energy.

Creating 3 Inadvertent Interchange Standards, one addressing the transmission component, one addressing the frequency component and one addressing the energy component, will allow the Inadvertent energy to be settled in a manner comparable to settlement of Energy Imbalance. The actual Inadvertent energy settlement methodology will be determined by the markets, in compliance with Market Interface Principles 3 and 4. The JIITF recommends the Inadvertent energy standards (1) contain settlement options that allow the markets to financially settle Inadvertent energy on an hourly basis, thus eliminating the accumulation problem, or (2) implement additional rules that enforce appropriate management of accumulations.

Inadvertent Interchange Balance

Some amount of inadvertent is reasonable and inevitable. A Balancing Authority's Inadvertent accumulation, will increase, decrease or fluctuate, over time. The short-term goal is to keep good CPS scores. Inadvertent energy is a component of AIE whose instantaneously measured equivalent is ACE, which is included in CPS1. Inadvertent is zero when the Net Actual Interchange is equal to the Net Scheduled Interchange each hour. The long-term goal is to appropriately manage Inadvertent accumulation. This goal requires Balancing Authorities incorporate settlement policies within their Interconnection, in a timely manner.

Existing NERC Policy 1F supports the short-term and long-term goals by stating: "Each Control Area [Balancing Authority] shall be active in preventing unintentional Inadvertent Interchange accumulation. Each Balancing Authority shall also be diligent in reducing accumulated inadvertent balances in accordance with Operating Policies." This Policy sets no limits on the amount of Inadvertent that can be accumulated or when it must be paid back. Compensation is only required through payback of the inadvertent energy in MWh. The "settlement" energy may not reflect the market value when the Inadvertent was created by Balancing Authorities' frequency support. The ERCOT Interconnection requires Inadvertent payment in financial terms and the Western Interconnection allows Inadvertent payment in financial terms. The Western Interconnection also has Balancing Authority Inadvertent accumulation limits and allows energy bilateral pay-back transactions without transmission charges.

Addressing the Operating Committee Requirements

The Operating Committee (OC) charged the JIITF with developing Inadvertent Interchange Operating Standards that include market incentives and penalties that provide for the following two requirements:

- Allow for reasonable variations in generation control, and
- Encourage minimizing imbalances due to poor control.

When the Control Area Criteria Task Force made the above recommendation to the OC, it was feasible for a NERC Subcommittee to craft such a standard. Since that time the NERC Board of Trustees implemented The Standards Authorization Process Manual. This manual defines the characteristics of a NERC Organization Standard and establishes the process for development of consensus for approval, revision, reaffirmation, and withdrawal of such standards. All Organizational Standards shall be consistent with all Market Interface Principles.

Two Market Interface Principles limit the JIITF in recommending incentives, penalties, and the Inadvertent Interchange energy component settlement/pay-back methodology. These are: Market Interface Principle 3, *An Organization Standard shall neither mandate nor prohibit any specific market structure*; and Market Interface Principle 4, *An Organization Standard shall not preclude market solutions to achieving compliance with that standard*.

The JIITF also notes that NERC already has Control Performance Standards in place that set the target for frequency and tie-line error to be enforced by NERC. The JIITF cannot apply CPS1 directly in the OC's charge because CPS1 does not measure Inadvertent Interchange. Accordingly JIITF is recommending standards that complement and assist CPS but do not replace or supersede CPS.

The JIITF recommends local standards for Inadvertent transmission use, one standard for Inadvertent frequency control and one standard for the Inadvertent energy component, thus satisfying the two OC criteria.

Allow for reasonable variations in generation control.

The proposed standard addressing frequency control contribution will not preclude a Balancing Authority from experiencing reasonable variations in generation control.

The proposed standard addressing the Inadvertent energy component will not restrict variation in generation control. In fact some Inadvertent is inevitable and expected.

Encourage minimizing imbalances due to poor control.

The proposed standard addressing frequency control contribution will have incentives and penalties that will reward good control and penalize poor control. The incentives and penalties need to be sufficient to promote good performance.

The proposed standard addressing the Inadvertent energy component will define what Inadvertent energy is, allow alternate methods for settlement/pay-back (i.e. energy in-kind or financial settlement), and state that the energy markets will determine the incentives, penalties and methodologies.

JIITF Proposed Inadvertent Solutions

The JIITF considered a number of Inadvertent proposals. The Task Force reached a major milestone when it decided by general consensus to separate the reliability components (transmission loading and frequency control) from the commodity component (energy). The results are:

1. The JIITF recommends that the conventional Inadvertent Interchange calculation and methodology be separated into: 1) a reliability (transmission loading) component, 2) a reliability (frequency control) component, and 3) an energy component.

    a. The Transmission Loading component is viewed by the JIITF, to be a reliability service. The JIITF recommends a Transmission Loading Standard be developed for each region that is consistent with the transmission market design used in that region. In line with other control obligation services, Transmission Loading is recommended by the JIITF to be treated as an Interconnected Operations (ancillary) Service. This proposed Transmission Loading service should be addressed, controlled and priced in a manner similar to other ancillary services. See Attachment 3 for a discussion indicating why a general interconnection wide standard cannot be developed at this time.

    b. The Inadvertent Frequency Control Component is viewed by the JIITF to be an obligatory reliability service. The JIITF recommends a Frequency Control Contribution Standard. In line with other control obligation services, frequency control is recommended by the JIITF to be treated as an Interconnected Operations (ancillary) Service. This proposed frequency control service should be addressed, controlled and priced in a manner similar to other ancillary services. See Attachment 4.

        i. A "Frequency Control Contribution" (FCC) metric was developed by Howard Illian, a member of the JIITF, as a response to the Inadvertent Interchange challenge. The Illian metric is a statistical measurement of frequency response contained within unscheduled energy. Absent a market to determine the FCC unit price, JIITF member Robert Blohm proposed a price formula to be monetized by NERC. The JIITF recommends the Illian frequency control metric for the obligatory reliability service, priced for now by the Blohm formula. See Attachment 4.

    c. The Inadvertent energy component is considered a market commodity that has reliability implications. The JIITF recommends an Inadvertent Standard that defines Inadvertent, determines the Inadvertent calculation, and allows for alternate Inadvertent settlement mechanisms (i.e. energy in-kind or financial settlement). See Attachment 5.

i. In accordance with Market Principles 3 and 4, the markets will determine the Inadvertent energy pay-back/settlement/cash-out (including pricing, penalties and incentives). If necessary the markets will assign a value to the Inadvertent energy component. Market Principles are found in Attachment 1.

2. Existing Inadvertent balances, accumulated under the existing policy, must be eliminated or minimized in a fair manner. One option is to freeze the existing balances when the new Inadvertent Standard is implemented, then eliminate the frozen balances through bilateral schedules over a fixed period of time (e.g. the following 12 months).

    a. In order to minimize the impact of the "frozen balance" payback recommendation above, the JIITF recommends the Resources Subcommittee target Balancing Authorities with current accumulation of AIE in excess of "100 times L_{60}" and require these Balancing Authorities to develop an Inadvertent management plan to reduce or eliminate this balance. The respective Inadvertent management plans are required to be submitted to the Resources Subcommittee for approval. Definition and justification of the "100 times L_{60}" proposal is included in Attachment 6.

3. The JIITF recommends the proposed standards methodologies and calculations be proven feasible and accurate to a high degree by being subjected to field tests to acquire satisfactory data before wide industry application. This is in accordance with the Organization Standards Process Manual and is important in preparation for future compliance penalties and sanctions.

4. The JIITF recommends all three Standards be based on hourly time periods. Data validation and dispute resolution are essential to ensure successful implementation. If Inadvertent is cashed out through a market process or if there are cash penalties/rewards for extreme hourly values of FCC, an independent clearinghouse that expeditiously "balances the books" for each Interconnection is highly recommended. An expanded discussion on data validation and dispute resolution is in Attachment 8.

These JIITF Proposed Inadvertent Solutions give direction to develop Transmission Loading Contribution, Frequency Control Contribution, and Inadvertent Interchange Standards that meet the requirements of the OC charge.

ATTACHMENT 1

Organization Standard Principles

The Inadvertent Interchange principles, methodologies, and proposed standards must comply with the requirements of the NERC Organization Standards.

Reliability Principles

NERC Organization Standards are based on certain Reliability Principles that define the foundation of reliability for North American bulk electric systems. Each Organization Standard shall enable or support one or more of the following Reliability Principles, thereby ensuring that each standard serves a purpose in support of reliability of the North American bulk electric systems. Each Organization Standard shall also be consistent with all of these Reliability Principles, thereby ensuring that no standard undermines reliability through an unintended consequence.

Reliability Principle 1 – Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and prescribed abnormal conditions.

{JIITF believes the proposed transmission loading service and Inadvertent Standards support Principle #1.}

Reliability Principle 2 – The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

{JIITF believes the proposed frequency control services supports Principle #2.}

Reliability Principle 3 – Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.

Reliability Principle 4 – Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.

Reliability Principle 5 – Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk electric systems.

Reliability Principle 6 – Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified, and have the responsibility and authority to implement actions.

Reliability Principle 7 – The security of the interconnected bulk electric systems shall be assessed, monitored, and maintained on a wide-area basis.

Market Interface Principles

Recognizing that bulk electric system reliability and electricity markets are inseparable and mutually interdependent, all Organization Standards shall be consistent with these Market Interface Principles. Consideration of these Market Interface Principles is intended to assure Organization Standards are written such that they achieve their reliability objective without causing undue restrictions or adverse impacts on competitive electricity markets.

Market Interface Principle 1 – The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy.

> *{The proposed frequency control service realizes that some amount of frequency error is inevitable. However, frequency control is a reliability obligation and whoever uses this service should compensate the entity that supplied it as Inadvertent. The difference between scheduled and actual energy needs to be controlled in order to avoid undesirable reliability degradation.}*

Market Interface Principle 2 – An Organization Standard shall not give any market participant an unfair competitive advantage.

> *{This the heart of the comparability issue. By separating the reliability component (frequency) from the commodity component (energy), the JIITF proposal has leveled the playing field.}*

Market Interface Principle 3 – An Organization Standard shall neither mandate nor prohibit any specific market structure.

{The JIITF's goal is to provide the market with a performance measure that has reliability attributes built into it. This principle precludes the JIITF from recommending how the markets will structure the Inadvertent pay-back/settlement/cash-out (including pricing, penalties and incentives).}

Market Interface Principle 4 – An Organization Standard shall not preclude market solutions to achieving compliance with that standard.

{Each market may have unique solutions. This principle precludes the JIITF from recommending market solutions and is similar to Principle 3 (see above).}

Market Interface Principle 5 – An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.

{The JIITF is sensitive to the proposed measures requiring hourly net schedule and actual Interchange values.}

JIITF Inadvertent Interchange Principles

Inadvertent Principle 1 – Inadvertent Interchange across an interconnection always equals zero (the system's energy is necessarily balanced regardless of frequency control and the overall health of the interconnection).

Inadvertent Principle 2 – Locational price models do not guarantee zero sum financial systems for Inadvertent Payback.

Inadvertent Principle 3 – Inadvertent Interchange is sometimes the symptom of a reliability problem. Inadvertent resulting from "bad" control is the cause and inadvertent resulting from "good" control is the response."

Inadvertent Principle 4 – Inadvertent Interchange is unavoidable for the reliable operation of an Interconnected system.

Inadvertent Principle 5 – Incorrectly aligned Inadvertent economic incentives create uncertainty and risk. Ultimately, reliability and economic efficiency are compromised.

Inadvertent Principle 6 – Inadvertent as a result of "good" control should receive an incentive. Inadvertent as the result of "bad" control should receive a penalty.

Inadvertent Principle 7 – The Inadvertent methodology must equitably share the benefits of Inadvertent Interchange among all participants, satisfying the comparability requirement.

Inadvertent Principle 8 – Inadvertent Balance should be "bounded" by a limit consistent with economical operation of the system without compromising reliability.

Inadvertent Principle 9 – Inadvertent Interchange Standard must adhere to Reliability and Market Interface Principles.

ATTACHMENT 2

Sources of Inadvertent Interchange

If scheduled energy matches the metered values at the interconnection point, for a given time period, there is no actual Inadvertent Interchange created. The variation of generation to load on a real time basis will cause a certain amount of Inadvertent Interchange. Due to the nature of electricity, a zero Inadvertent Balance for any single entity is a coincidence rather than an expectation. It is economically unrealistic to expect to eliminate Inadvertent Interchange completely. Imbalance, frequency error, frequency control, and inadvertent are inextricably linked. Frequency error is permitted due to a long-standing understanding that the cost of reducing frequency error can exceed the benefit of error reduction.

The JIITF identified five general sources of Inadvertent Interchange, these are:

1. Scheduling Error
    a. Improper entry of data (time, amount, direction, duration, etc.)
    b. Improper update in real-time (TLR miscommunication etc.)
2. Meter Error
    a. Loss of telemetry
    b. Difference between real-time and MWh integrated values
3. Unintentional Control Error
    a. Regulation Inadequacy
        i. Insufficient regulating resources committed
        ii. Poor control algorithm
    b. Load volatility and unpredictability
    c. Generation outages
    d. Generation deviations
4. Ramping Representation Error
    a. Practice of using contract Net Interchange Schedules instead of integrated Net Interchange Schedules (the ramping effect)

5. Intentional Control Adjustment

    a. Bias contribution (including time correction)

    b. Unilateral payback (beyond corrections for primary Inadvertent)

ATTACHMENT 3

JIITF Proposal

Transmission Loading/Obligatory Reliability Service Local Standard

Brief Description: Control Methodology to Support Transmission Loading Limits.

Principle to Which Standard Applies: **Reliability Principle 1** – Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and prescribed abnormal conditions.

Entity(s) to Which Proposed or Revised Standard Applies: Entities performing the Transmission Service Provider function.

Purpose of Standard (Should Provide Reliability Basis for the Standard): Regarding Transmission Loading Contribution as an Obligatory Reliability Service reinforces the importance of Transmission Limits to the overall reliability aspects of the Bulk Electric System. It also insures that the Inadvertent settlement mechanism does not become a means to bypass charges and penalties for unscheduled transmission use including use of constrained transmission and TLR bypass.

The differences in market designs and implementation across North America prevent the development of a single Reliability Service to represent the contribution of Inadvertent to Transmission Congestion or Load Management. In an ideal world, the Transmission Loading Contribution of Inadvertent would be one of three observable independent components of the final Value of Inadvertent. The other two are the Frequency Control Contribution and the Market Value of Energy. Some markets have chosen to combine the Transmission Loading Contribution of Inadvertent with the Market Value of Energy, thus preventing the development of a Reliability Service whose Value isn't based on Energy. Other markets have chosen to keep the Transmission Loading Contribution of Inadvertent separate from the Market Value of Energy, allowing the future development of a Reliability Service whose price isn't based on Energy. The Transmission Loading Contribution must be defined in a manner that is compatible with local methods of determining congestion in different transmission and/or energy market designs. Therefore, the Transmission Loading Contribution of Inadvertent must be defined as a local requirement.

ATTACHMENT 4

JIITF Proposal

Frequency Control / Obligatory Reliability Service Operating Standard

Brief Description: Control Methodology to Support Interconnected Frequency, 60 Hz

Principle to Which Standard Applies: **Reliability Principle 2** – The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

Entity(s) to Which Proposed or Revised Standard Applies: Entities performing Balancing Authority functions

Purpose of Standard (Should Provide Reliability Basis for the Standard): The Frequency Control Contribution Standard determines how much compensation Balancing Authorities must receive or pay for Obligatory Reliability Service in the form of Frequency Response that they provided to or extracted from the Interconnection. Supply or use of Frequency Response is contained within a Balancing Authority's Inadvertent.

The Frequency Control Contribution (***FCC*$_{BA}$**) for each Balancing Authority shall be calculated on the basis of hourly average data as follows:

$$FCC_{BA} = \frac{Sum\left(Inadvertent_{BA} \times Frequency\_Error_{Int}\right)}{Sum\left(Frequency\_Error_{Int} \times Frequency\_Error_{Int}\right)} \times Hours\_in\_Period \quad \textbf{(1)}$$

where ***Inadvertent*$_{BA}$** : Inadvertent for a Balancing Authority for the hour, in MW.

***Frequency_Error*$_{Int}$** : Interconnection Frequency Error for the hour, in Hz.

Hours_in_Period : Hours in the settlement period, i.e. a Month.

Sum( ) : Sum of hourly measurements over the period.

The above calculation simply determines (by the "least squares" estimation technique) how much of the hourly frequency error was due to the inadvertent energy incurred by the Balancing Authority and, therefore, how much Frequency Response, as measured with hourly average data, was supplied or demanded with the Inadvertent energy incurred. This "Frequency Response" is a valid measure of how much frequency control service (Frequency Response, Regulation, Reserves, and Load Following) was supplied or used by the Balancing Authority along with the Inadvertent energy.

The payment $FCC\$_{BA}$ that should be exchanged between the Balancing Authorities for the use/provision of frequency control services is then determined by multiplying the result from equation (1) by a settlement price $Price_{Int}$, the Frequency Response Price.

$$FCC\$_{BA} = FCC_{BA} \times Price_{Int} \quad \textbf{(2)}$$

where $FCC\$_{BA}$: Frequency Response Settlement for settlement period, e.g. a Month.

$Price_{Int}$: Frequency Response Price, $ for each MW per Hz.

Until there is a market price, price will be determined as follows:

$$Price_{Int} = m\$_{NERC} \times Avg\left(Frequency\_Error_{Int} \times Frequency\_Error_{Int}\right) \quad \textbf{(3)}$$

where $m\$_{NERC}$: Monetary Basis--a fixed amount m in dollars--set by NERC.

$Avg(\ )$: = Average hourly measurement over the period.

Since $Sum(\ ) = Avg(\ )$ **x** $Hours\_in\_Period$ equation (2) reduces to:

$$FCC\$_{BA} = Sum\left(Inadvertent_{BA} \times Frequency\_Error_{Int}\right) \times m\$_{NERC} \quad \textbf{(4)}$$

The Monetary Basis will be set by NERC, or other appropriate organization, at a level just sufficient to assure minimum acceptable frequency control until an appropriate market in frequency control services has been established to set the price. The dependence of price on the average square of hourly frequency error experienced over the period reasonably mimics the expected effect that the quality of frequency control provided would have on a market price. As experienced frequency control (measured as the period average "variance" of frequency, or "square" of frequency error) improves, the price is reduced-and, as experienced frequency control

degrades, the price increases. Using this price formula also has the practical benefit of collapsing the $\boldsymbol{FCC\$_{BA}}$ standard to the extremely simple final equation (4). Once a market in frequency control services is established, a market settlement price will take over from the set $\boldsymbol{Price_{Int}}$ for this service and the formula in effect for $\boldsymbol{FCC\$_{BA}}$ will revert back to equation **(2)** from equation (4).

ATTACHMENT 5

JIITF Proposal

Inadvertent Energy Operating Standard

Brief Description: Inadvertent Energy is the difference in energy between a Balancing Authority's Net Actual and Net Scheduled Interchange and is considered a market commodity. Control is necessary for reliability of the Bulk Electric System.

Principle to Which Standard Applies: **Reliability Principle 1 – Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and prescribed abnormal conditions.**

Entity(s) to Which Proposed or Revised Standard Applies: Entities performing Balancing Authority functions

Purpose of Standard (Should Provide Reliability Basis for the Standard): **This standard requires the Balancing Authorities have Inadvertent Interchange policies.** The energy component of the existing Inadvertent Interchange calculation, if not controlled, can cause imbalances that can lead to degradation of the Interconnection. To avert this negative condition, the Inadvertent energy component must be defined, managed and settled. However, in accordance with Market Principles 3 and 4, the markets will determine the Inadvertent energy pay-back/settlement/cash-out (including pricing, penalties and incentives).

Inadvertent Interchange energy component shall be calculated as follows:

Inadvertent Energy Formula

$$I_i = (NI_A - NI_S)$$

where I_i is Inadvertent Energy of Balancing Authority i

NI_A is Actual Net Interchange

NI_S is Scheduled Net Interchange

Note: The Inadvertent Energy Standard, Attachment #5, including the Inadvertent Energy Formula, is in development and receives constructive criticism after each adjustment. The JIITF

is using this opportunity to incorporate a high degree of accuracy into the Inadvertent Energy Formula and is considering the inclusion of additional Interchange components such as ramping and Scheduled Inadvertent Payback.

ATTACHMENT 6

"100 times L_{60} Proposal"

Transitional Limit on Inadvertent Accumulations

Transitional Inadvertent accumulation for purposes of this paper means the accumulated Inadvertent balances that are currently on record or will be accumulated during the time it takes the proposed Frequency Control Contribution and Inadvertent Energy Standards to be developed and implemented.

Balancing Authorities currently accumulate on-peak and off-peak inadvertent energy accounts. NERC Policy 1F encourages Balancing Authorities to keep these accounts small. However, there is no limit on the magnitude of the accumulated balances. In the West, a "20xBias" limit has been successfully applied. The JIITF recommends a technically justifiable Inadvertent accumulation limit.

While one of the Balancing Authority's goals is to maintain a zero ACE on average over a long period of time, the measure of inadvertent accumulation must be annually accumulated AIE. Placing a strict enough limit on annually accumulated AIE prevents perverse pay-back incentives and catches the entities causing long term frequency error soon enough. The JIITF propose a limit that provides for 90% confidence in not holding entities to be excessively accumulating AIE because of a bias in control. The following is a short derivation of the proposed limit.

> Consider a hypothetical limiting Balancing Authority that has an ACE distribution that is normal and unbiased, and has historical performance equal to the observed performance of the interconnection as a whole (maximum allowed performance). Any Balancing Authority's long run (annual) accumulation should be no larger than the worst likely accumulation over a year of random drawings made once each hour from the limiting Balancing Authority's ACE distribution.
>
> We have to begin the derivation by dividing a Balancing Authority's unbiased ACE distribution's variance s^2, or average squared deviation from zero, by the number of hours of the year, to get a measure of the allowed average over a year of hourly AIE. [We don't divide an unbiased ACE's average deviation from zero which is zero by definition of "unbiased" because the deviations occur in opposite directions and cancel out.] We then take the positive square root ("standard" deviation) of the result to get the measure of the allowed average over a year of hourly AIE:

$$Avg(AIE)_{year} = \sqrt{\frac{s^2}{N_{60-\min ute\_periods\_in\_year}}} \qquad \textbf{(1)}$$

where s is the standard deviation of a balancing Authority's unbiased normally distributed ACE.

We call $s_{allowed}$ the maximum allowed such standard deviation, that of the hypothetical limiting Balancing Authority, with

$$s_{allowed} = e_{60} \times \sqrt{B_I \times B_{CA}} \qquad \textbf{3(2)}$$

where e_{60} is the historical and observed standard deviation of frequency (~0.008 Hz for the Eastern Interconnection)

$\boldsymbol{B_{CA}}$ is 10 times the Balancing Authority's bias (MW/.1Hz)

$\boldsymbol{B_I}$ is 10 times the sum of all the Balancing Authorities' biases (MW/.1Hz).

Setting the limit on a Balancing Authority's $Avg(AIE)_{year}$ such that, allowing for statistical bias, there is 90 % confidence that any hour's ACE sample is within or at $1.65 \times s_{allowed}$, we get

$$Avg(AIE)_{year} \le 1.65 \times \frac{s_{allowed}}{\sqrt{N_{60-\min ute\_periods\_in\_year}}} \qquad \textbf{(3)}$$

where 1.65 is the statistical conversion factor from a 68.3 % confidence limit (1 standard deviation) to a 90 % confidence limit.

Substituting ($\boldsymbol{L_{60}}$/1.65) for $s_{allowed}$, we get

$$Avg(AIE)_{year} \le \frac{L_{60}}{\sqrt{8760}} \qquad \textbf{(4)},$$

where L_{60} is the maximum allowed biased standard deviation of any Balancing Authority's ACE--a maximum likely to exceed or equal with 90 % confidence any hour's sample of that ACE due to statistical bias,

We multiply back the right-hand side of equation (4) by the 8760 hours in the year to get the annual energy accumulation limit

$$AIE_{accumulation\_limit} = L_{60} \times \sqrt{8760}\ . \qquad \textbf{(5)}$$

Rounding up $\sqrt{8760}(=93.6)$ to 100 yields the proposed inadvertent accumulation limit, to wit

$$AIE_{accumulation} \leq 100 \times L_{60}\ . \qquad \textbf{(6)}$$

The "one hundred times $\boldsymbol{L_{60}}$" limit on accumulated AIE allows annual accumulations no bigger than 100 times the maximum allowed biased standard deviation of a Balancing Authority's ACE--a maximum that is set to exceed or equal with 90 % confidence any Balancing Authority's ACE due to statistical bias. This places a technically justified limit on accumulations of inadvertent without creating perverse payback incentives. It allows for reasonable generation and load variation, but not excessive use of inadvertent accounts.

ATTACHMENT 7

Time Error Correction

Time Error Correction

Traditional methods of managing Inadvertent (accumulated Inadvertent accounts and payback-in-kind) demonstrate that Time Error is manageable. Time Error Correction allows the unintentional Inadvertent, in the opposite direction, to be paid back to the Interconnection unilaterally. This unilateral payback of Inadvertent corrects the inadvertent accounts of Balancing Authorities that took or supplied Inadvertent in the opposite direction and corrects Time Error at the same time. Unilateral Time Error Corrections performed interconnection-wide that happen to be in the same direction as the Balancing Authorities' Inadvertent account have the effect of stranding Inadvertent on the interconnection. This condition reduces the effectiveness of the payback process.

Historically, these considerations have not significantly influenced the North American Interconnections with respect to Time Error Correction procedures. Until recently, interconnection-wide, Time Error Corrections have been performed as needed stranding Inadvertent, and little attempt has been made to identify unintentional inadvertent for unilateral payback. The exception to this is the recently implemented time error corrections procedures implemented on the Western Interconnection. The procedures identify “Primary Inadvertent” and implements only “Primary Inadvertent” payback.

Effect of JIITF Recommendations on Time Error Correction

The recommendations of the JIITF will not adversely affect the above Inadvertent payback-in-kind process. It will, however, cause those choosing to perform unilateral Inadvertent payback, to be more sensitive about the effect that the unilateral payback will have on interconnection frequency. Unilateral payback will be more likely to occur when it will help restore frequency to schedule, and less likely to occur when it will contribute to additional frequency error. Both of these effects are likely to improve reliability.

If Inadvertent is settled with a cash out process, the automatic Time Error correction effect of unilateral Inadvertent payback will be eliminated. Reductions in this automatic Time Error correction can easily be compensated for with interconnection wide Time Error Corrections. The interconnection wide Time Error Corrections will have no effect on the settlement of either the Inadvertent or the Frequency Control Contribution since pure Time Error Corrections do not create either Inadvertent or Frequency Error from schedule. Only the failure to provide effective control during the Time Error Correction process will cause additional inadvertent, and that inadvertent will also create associated Transmission Loading Components and Frequency Control Components incenting effective control. Therefore, interconnection Time Error

Corrections will not affect the energy, Transmission Loading Contribution or Frequency Control Contribution settlement process.

The results of the JIITF proposed solutions are changes that result in Inadvertent Management decisions and Time Error Correction decisions that are independent of each other.

ATTACHMENT 8

Data Validation and Dispute Resolution

Data Validation

The Inadvertent Interchange Operating Standard end-state will depend on due process and ultimately actual experience. The JIITF highly recommends an independent clearinghouse that expeditiously "balances the books" for each Interconnection, especially if Inadvertent energy is cashed out through a market process or if there are severe penalties for extreme hourly values in FCC.

Potential for abuse exists if the books are not balanced with validated data. Without a central clearinghouse, Balancing Authorities can sell energy "off the ties." In addition, excessive FCC that exposes a Balancing Authority to a penalty in an hour can be "moved" into other hours by editing tie-line data.

Validated data is essential for any standard where money is at stake (either through compliance or financial settlement).

Dispute Resolution

Disputes will be more frequent and more spirited if Inadvertent energy is settled on an hourly basis and/or settlement involves financial transactions. The process must be able to move forward even if one or more parties have disputes.

To expeditiously balance hourly books (each day), on an Interconnection level, the JIITF recommends a streamlined process be developed, approved and implemented. The process includes an independent clearinghouse that, in effect, is a large matrix that accepts Balancing Authorities' actual and scheduled data. The "Interconnection Books" cannot close until all differences are resolved between "partners." However, when values for either scheduled or actual Interchange are contested, the independent clearinghouse would implement a procedure to balance the Interconnection Books, on an interim basis.

Ultimately, if the "partners" cannot come to an agreement on the contested Inadvertent Interchange, a dispute resolution process would be implemented to determine a final resolution.

Policy 1 – Generation Control and Performance

Version 2

Policy Subsections

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

Introduction

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

A. Control Performance Standard

[Appendix 1A, "Area Control Error (ACE) Equation"]
["Performance Standard Training Document"]

Introduction

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

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

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

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

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

specific limit. This limit $\in_1^2$ is a constant derived from a targeted frequency bound (separately calculated for each INTERCONNECTION) reviewed and set as necessary by the NERC Resources Subcommittee. [See the "**Performance Standard Training Document"** for application for variable frequency bias.]

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

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

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,

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

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

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

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

B. Disturbance Control Standard

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

Introduction

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

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

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

Standards

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

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

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

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

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

2.2. **Disturbance Control Standard Compliance.** When a CONTROL AREA or RESERVE SHARING GROUP experiences a REPORTABLE DISTURBANCE (SEE 2.4), it is compliant

with the Disturbance Control Standard when the DISTURBANCE RECOVERY CRITERION is met within the DISTURBANCE RECOVERY PERIOD. Each CONTROL AREA or RESERVE SHARING GROUP shall meet the Disturbance Control Standard (DCS) 100% of the time for REPORTABLE DISTURBANCES.

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

2.2.2. DISTURBANCE RECOVERY PERIOD. The default DISTURBANCE RECOVERY PERIOD is 15 minutes after the start of a REPORTABLE DISTURBANCE. This period may be adjusted to better suit the needs of an INTERCONNECTION based on analysis approved by the NERC Resources Subcommittee and the NERC Operating Committee.

2.3. RESERVE SHARING GROUP. Each RESERVE SHARING GROUP shall comply with the Disturbance Control Standard. A RESERVE SHARING GROUP shall be considered in a DISTURBANCE condition whenever a group member has experienced a REPORTABLE DISTURBANCE and calls for the activation of CONTINGENCY RESERVES from one or more other group members. (If a group member has experienced a REPORTABLE DISTURBANCE condition but does not call for reserve activation from other members of the RESERVE SHARING GROUP, then that member shall report as a single CONTROL AREA.) Compliance may be demonstrated by either of the following two methods:

2.3.1. Group compliance to Disturbance Control Standard. The RESERVE SHARING GROUP reviews group ACE (or equivalent) and demonstrates compliance to the DCS. To be in compliance, the group ACE (or its equivalent) must meet the DISTURBANCE RECOVERY CRITERION after the schedule change(s) related to reserve sharing have been fully implemented, and within the DISTURBANCE RECOVERY PERIOD.

2.3.2. Group member compliance to Disturbance Control Standard. The RESERVE SHARING GROUP reviews each member's ACE in response to the activation of reserves. To be in compliance, a member's ACE (or its equivalent) must meet the DISTURBANCE RECOVERY CRITERION after the schedule change(s) related to reserve sharing have been fully implemented, and within the DISTURBANCE RECOVERY PERIOD. [See Requirement 2.2.2 above.]

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

2.5. Treatment of Multiple Contingencies.

2.5.1. Simultaneous Contingencies. Multiple contingencies occurring within one minute or less of each other shall be treated as a single contingency. If the combined magnitude of the multiple contingencies exceeds the MOST SEVERE

SINGLE CONTINGENCY, the loss shall be reported, but excluded from compliance evaluation.

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

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

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

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

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

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

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

C. Frequency Response and Bias

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

Requirements

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

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

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

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

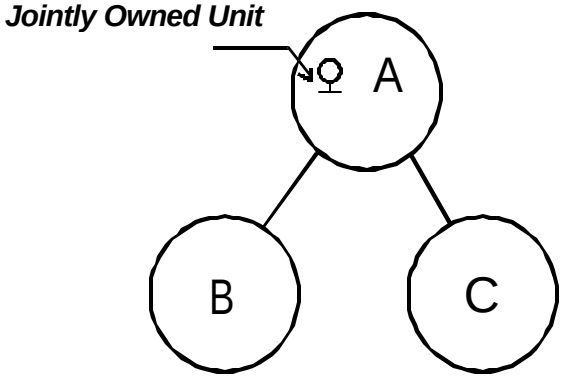
Standards

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

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

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

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



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

OWNED UNIT should *not* include their share of the governor droop response in their FREQUENCY BIAS SETTING.

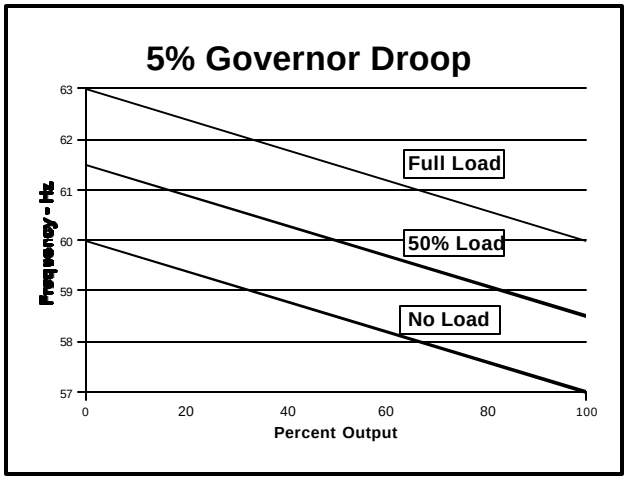
1.1.4. Minimum bias setting for CONTROL AREAS that serve native LOAD. The CONTROL AREA'S monthly average FREQUENCY BIAS SETTING must be at least 1% of the CONTROL AREA'S estimated yearly peak demand per 0.1 Hz change as described in the Frequency Response Characteristic Survey Training Document.

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

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

Guides

1. **Governor installation.** Generating units with nameplate ratings of 10 MW or greater should be equipped with governors operational for frequency response unless restricted by regulatory mandates
2. **Governors free to respond.** Turbine governors and HVDC controls, where applicable, should be allowed to respond to system frequency deviation, unless there is a temporary operating problem.
3. **Governor droop.** All turbine generators equipped with governors should be capable of providing immediate and sustained response to abnormal frequency excursions. Governors should provide a 5% droop characteristic. Governors should, as a minimum, be fully responsive to frequency deviations exceeding ± 0.036 Hz (± 36 mHZ).
4. **Governor limits.** Turbine control systems that provide adjustable limits to governor valve movement (valve position limit or equivalent) should not restrict travel more than necessary to coordinate boiler and turbine response characteristics



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

D. Time Control Standard

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

Introduction

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

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

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

Standard

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

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

Requirements

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

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

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

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

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

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

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

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

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

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

E. Automatic Generation Control Standard

[Appendix 1A – The Area Control Error (ACE) Equation]
[Performance Standard Training Document]

Introduction

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

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

2. Resource Requirements

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

2.2. Regulation Service.

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

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

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

3. AUTOMATIC GENERATION CONTROL (AGC).

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

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

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

4. Data Requirements.

4.1. Data scan rates for ACE. The Control Area shall ensure that data-acquisition for and calculation of ACE occur at least every six seconds.

4.2. Frequency. Each CONTROL AREA shall provide redundant and independent frequency metering equipment that shall automatically activate upon detection of failure of the primary source. This overall installation shall provide a minimum availability of 99.95%.

4.3. NET SCHEDULED INTERCHANGE.[1]

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

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

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

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

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

4.4. Actual Net Interchange.[2]

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

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

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

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

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

[2] Actual Interchange is always measured between PHYSICALLY ADJACENT CONTROL AREAS as explained in the "Interchange Reference Document."

4.5. Verification of Tie Flows

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

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

4.6. Data Recording and Display.

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

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

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

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

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

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

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

Device	*Accuracy*	*Units*
Digital frequency transducer	≤ 0.001	Hz
MW, MVAR, and voltage transducer	≤ 0.25	% of full scale
Remote terminal unit	≤ 0.25	
Potential transformer	≤ 0.30	
Current transformer	≤ 0.50	

4.8. Data Retention.

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

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

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

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

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

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

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

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

F. Inadvertent Interchange Standard

[Appendix 1F, "Inadvertent Interchange Dispute Resolution Process and Error Adjustment Procedures"]
["Inadvertent Interchange Accounting Training Document"]
[Policy 3, "Introduction"]

Introduction

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

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

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

Standards

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

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

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

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

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

4.1.1. The hourly values of NET INTERCHANGE SCHEDULE.

4.1.2. The hourly integrated MWh values of NET ACTUAL INTERCHANGE

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

4.3. After-the-Fact Corrections. After-the-fact corrections to the agreed-to Daily and Monthly accounting data shall only be made to reflect actual operating conditions (e.g. a meter being used for control was sending bad data). Changes or corrections based on non-reliability considerations shall not be reflected in the CONTROL AREA's INADVERTENT INTERCHANGE. After-the-fact corrections to scheduled or actual values will not be accepted without agreement of the ADJACENT CONTROL AREA(s).

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

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

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

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

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

5.1.2. Unilateral payback. INADVERTENT INTERCHANGE accumulations may be paid back unilaterally controlling to a target of non-zero ACE. Controlling to a non-zero ACE ensures that the unilateral payback is accounted for in the CPS calculations. The unilateral payback control offset is limited to the CONTROL AREA's L_{10} limit and shall not burden the INTERCONNECTION**.**

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

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

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

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

6.2.1. Failure to Report. A CONTROL AREA that neither submits a report nor supplies a reason for not submitting the required data by the 20th calendar day of the following month shall be considered non-compliant.

6.2.2. Dispute Resolution. Adjacent CONTROL AREAS that cannot mutually agree upon their respective NET ACTUAL INTERCHANGE or NET SCHEDULED INTERCHANGE quantities by the 15th calendar day of the following month shall, for the purposes of dispute resolution, submit a report to their respective Resources Subcommittee Survey Contact. The report shall describe the nature and the cause of the dispute as well as a process for correcting the discrepancy. The Dispute Resolution Process is described in **Appendix 1F, "Inadvertent Interchange Dispute Resolution Process and Error Adjustment Procedures."**

G. Surveys Standard

[Area Interchange Error Survey Training Document]
[Frequency Response Characteristic Survey Training Document]
[Performance Standard Training Document]

Introduction

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

Requirements

1. **On-request Surveys.** Each CONTROL AREA shall perform each of the following surveys, as described in the Performance Standard Training Document, when called for by the Resources Subcommittee:

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

1.2. **FRC survey.** Frequency Response Characteristic survey to determine the CONTROL AREAS' response to INTERCONNECTION FREQUENCY DEVIATIONS.

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

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

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

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

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

Section 2.1.3 is contingent upon approval of Section C, Version 2.

2.2. Inadvertent Interchange Summaries (surveys). Each Region shall prepare an Inadvertent Interchange summary monthly to monitor the CONTROL AREAS' monthly Inadvertent Interchange and all-time accumulated Inadvertent Interchange. Each Region shall submit a monthly accounting to NERC by the 22nd day following the end of the month being summarized.

Policy 3 – Interchange

Version 5

[See also, "Interchange Reference Document"]

Policy Subsections

Introduction

This Policy addresses the following issues:

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

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

A. Interchange Transaction Implementation

[Policy 2A, "Transmission—Transmission Operations"]
[Appendix 3A1, "Tag Submission and Response Timetables"]
[Appendix 3A2, "Tagging Across Interconnection Boundaries]
["E-Tag Reference Document"]
["Transaction Tagging Process within ERCOT Reference Document"]

Introduction

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

Requirements

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

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

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

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

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

2. **INTERCHANGE TRANSACTION tagging.** Each INTERCHANGE TRANSACTION shall be tagged before implementation as required by each INTERCONNECTION as specified in the **"E-Tag Reference Document," or "Transaction Tagging Process within ERCOT Reference Document."** In addition to providing necessary operating information, the INTERCHANGE

TRANSACTION tag is the official request from the PURCHASING-SELLING ENTITY to the CONTROL AREAS to implement the INTERCHANGE TRANSACTION. The information that must be provided on the tag is listed in **Appendix 3A4**.

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

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

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

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

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

[2] This includes all "grandfathered" and other "non-888" Point-to-Point Transmission Service

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

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

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

2.5. Confirmation of tag receipt. Confirmation of tag receipt shall be provided to the PURCHASING-SELLING ENTITY who submitted the tag in accordance with INTERCONNECTION tagging practices. **["E-Tag Reference Document"]**

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

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

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

NERC expects that Approval Entities have the proper resources to perform these assessments. Lack of these tools is not a reason to deny an Interchange Transaction. Resources include personnel and tools.

The CONTROL AREA assesses:

- TRANSACTION start and end time
- Energy profile (ability of generation maneuverability to accommodate)
- SCHEDULING PATH (proper connectivity of ADJACENT CONTROL AREAS)

The TRANSMISSION PROVIDER assesses:

- Valid OASIS reservation number or transmission contract identifier
- Proper transmission priority
- Energy profile accommodation (does energy profile fit OASIS reservation?)

- OASIS reservation accommodation of all INTERCHANGE TRANSACTIONS
- Loss accounting

The Generation Providing Entity and LOAD-SERVING ENTITY assess:

- TRANSACTION is valid representation of contractually agreed upon energy delivery

4.1. **Tag corrections**. During the CONTROL AREAS' and TRANSMISSION PROVIDERS' Assessment Time, the PURCHASING-SELLING ENTITY who submitted the tag may elect to submit a tag correction. Tag corrections are changes to an existing tag that do not affect the reliability impacts of the INTERCHANGE TRANSACTION; therefore, tag corrections do not require the complete re-assessment of the tag by all CONTROL AREAS and TRANSMISSION PROVIDERS on the SCHEDULING PATH, or the completion and submission of a new tag by the PURCHASING-SELLING ENTITY. The SINK CONTROL AREA shall notify all CONTROL AREAS and TRANSMISSION PROVIDERS on the SCHEDULING PATH of the correction, and specifically alert those entities for which a correction has impact. Entities who are impacted by the correction will have an opportunity to reevaluate the tag status. The timing requirements for corrections are found in **Appendix 3A1, "Tag Submission and Response Timetable**." Tag items that may be corrected are found in **Appendix 3A4, "Required Tag Data."** A description of those entities who may correct an INTERCHANGE TRANSACTION tag is found in **Appendix 3D, "Transaction Tag Actions." [See Appendix 3A1 Subsection C, Interchange Transaction Corrections]**

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

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

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

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

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

- Have been tagged in accordance with Requirement 2 above, or,

- Are exempt from tagging in accordance with Requirement 2.1 above.

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

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

B. Interchange Schedule Implementation

[Policy 2A, "Transmission—Transmission Operations"]

Introduction

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

Requirements

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

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

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

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

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

- INTERCHANGE SCHEDULE start and end time
- Ramp start time and rate
- Energy profile

This agreement shall be made before either the SENDING CONTROL AREA or RECEIVING CONTROL AREA makes any generation changes to implement the INTERCHANGE SCHEDULE.

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

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

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

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

5.1. **Total capacity of facilities.** The total capacity of both the owned and arranged-for transmission facilities in service between the two CONTROL AREAS, or

5.2. **Total Transfer Capability.** The established network Total Transfer Capability (TTC) between the CONTROL AREAS, which considers other transmission facilities available to them under specific arrangements, and the overall physical constraints of the transmission network. Total Transfer Capability is defined in *Available Transfer Capability Definitions and Determination,* NERC, June 1996.

C. Interchange Schedule Standards

Standards

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

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

3. **Ramp duration.** CONTROL AREAS shall use the ramp duration established by their INTERCONNECTION as follows unless they agree otherwise:

3.1. **INTERCHANGE SCHEDULES within the Eastern and ERCOT INTERCONNECTIONS.** ten-minute ramp duration.

3.2. **INTERCHANGE SCHEDULES within the Western INTERCONNECTION.** 20-minute ramp duration.

3.3. **INTERCHANGE SCHEDULES that cross an INTERCONNECTION boundary.** The CONTROL AREAS that implement INTERCHANGE SCHEDULES that cross an INTERCONNECTION boundary must use the same start time and ramp durations.

3.4. **Exceptions for Compliance with Disturbance Control Standard and Line Load Relief.** Ramp durations for INTERCHANGE SCHEDULES implemented for compliance with NERC's Disturbance Control Standard (recovery from a disturbance condition) and INTERCHANGE TRANSACTION curtailment in response to line loading relief procedures may be shorter, but must be identical for the SENDING CONTROL AREA and RECEIVING CONTROL AREA **[See also Policy1E2, "Generation Control Performance – Performance Standard."]**

4. **INTERCHANGE SCHEDULE accounting.** Block accounting shall be used.

D. Interchange Transaction Modification

Introduction

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

Requirements

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

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

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

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

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

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

- Generation Providing Entity
- Generation CONTROL AREA
- Transmission Providers
- TRANSMISSION CUSTOMERS
- Scheduling Entities (intermediate CONTROL AREAS)
- Intermediate PURCHASING-SELLING ENTITIES (Title-holders)
- Load CONTROL AREA
- LOAD-SERVING ENTITY
- Market Redispatch Notification Entities (if specified)

- Security Analysis Services

1.6. INTERCHANGE TRANSACTION modification confirmation. Depending on the type of change, certain entities must evaluate and approve or deny the INTERCHANGE TRANSACTION modification. The following tables illustrate the entities required to evaluate the modification and the criteria they should use in their evaluation. All other entities will be notified of the request.

Until the next revision of E-Tag 1.7.1 all entities will be required to approve or deny market initiated profile changes. Table 1.6 indicates the behaviors for E-Tag 1.7.1.

FERC Orders 888, 889, 638, and a provider's OATT guide transmission requests. Tagging policy shall not supersede OASIS requirements.

Table 1.6 – Interchange Transaction Modification

Until further notice, requirements and responsibilities listed below for "DC Tie Operating Transmission Providers" should be assigned to "DC Tie Operating Control Areas associated with a POR or POD that has been registered as a DC Tie Facility."

Type of Change	Evaluation Required of	Evaluation Criteria
Net Increases in Committed Transmission Reservations or changes in Loss Provision	Transmission Provider(s)	All requirements under the provider's OATT must be satisfied
	DC Tie Operating Transmission Provider(s)	DC tie can accommodate the requested capacity
Net Decreases in Committed Transmission Reservations	Transmission Provider(s) if energy flow exceeds Committed Transmission Reservations; otherwise no approval is necessary	All requirements under the provider's OATT must be satisfied
	DC Tie Operating Transmission Provider(s) if energy flow exceeds Committed Transmission Reservations; otherwise no approval is necessary	DC tie can accommodate the requested capacity
Increases in Energy Flow	Generation Control Area	Ability of generation maneuverability to accommodate the indicated energy profile (i.e., verify ramping capability, availability)
	Transmission Provider(s) if energy flow exceeds available capacity; otherwise no approval is necessary	All requirements under the provider's OATT must be satisfied
	DC Tie Operating Transmission Provider(s)	DC tie can accommodate the requested flow
	Load Control Area	Ability of generation and/or load maneuverability to accommodate the indicated demand profile (i.e., verify ramping capability, availability)

Decreases in Energy Flow	Generation Control Area	Ability of generation maneuverability to accommodate the indicated energy profile (i.e., verify ramping capability, availability)
	DC Tie Operating Transmission Provider(s)	DC tie can accommodate the requested flow
	Load Control Area	Ability of generation and/or load maneuverability to accommodate the indicated demand profile (i.e., verify ramping capability, availability)
The above requirements are cumulative; an increase in energy flow also requires a corresponding increase in capacity, then the requirements for both must be met (i.e., evaluators would be generation Control Area, load Control Area, Intermediate Control Areas, TRANSMISSION PROVIDERS, DC tie operating TRANSMISSION PROVIDER(S), generation providing entity*, LOAD-SERVING ENTITY*). In all the above cases, all previously defined viewing entities for the transaction will have rights to view the above requested changes. *GPEs and LSEs may provide their own approval service. The HOST CONTROL AREA is the default provider for approval services.		

1.7. **INTERCHANGE TRANSACTION modification and evaluation time.** To provide adequate time for INTERCHANGE SCHEDULE implementation, INTERCHANGE TRANSACTION modifications shall be requested and evaluated as specified in Section D of **Appendix 3A1, "Tag Submission and Evaluation Timetable."**

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

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

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

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

2.2. **Assignment of coordination responsibilities during a loss of generation.** At such times when a loss of generation necessitates curtailing INTERCHANGE TRANSACTIONS,

the Generation CONTROL AREA is responsible for coordinating the modifications to the appropriate INTERCHANGE TRANSACTION tags.

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

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

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

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

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

2.4. Coordination responsibilities of the requesting CONTROL AREA. The modification must be provided by the Requesting CONTROL AREA to the following INTERCHANGE TRANSACTION participants:

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

2.5. INTERCHANGE TRANSACTION modification confirmation. Reliability-based modifications must be evaluated and confirmed prior to implementation. The following table illustrates the entities required to evaluate and the criteria they should use in their evaluation. All other entities will be notified of the request.

Until further notice, requirements and responsibilities listed below for "DC Tie Operating Transmission Providers" should be assigned to "DC Tie Operating Control Areas associated with a POR or POD that has been registered as a DC Tie Facility."

Reliability-Based Modification Evaluation	
Generation Control Area	• Energy profile (ability of generation to accommodate)
DC Tie Operating Transmission Providers or Control Areas	• Energy profile (ability of tie to accommodate)
Load Control Area	• Energy profile (ability of load to accommodate)

2.6. INTERCHANGE TRANSACTION modification and evaluation time. To provide adequate time for INTERCHANGE SCHEDULE implementation, INTERCHANGE TRANSACTION modifications shall be requested and evaluated as specified in **Appendix 3A1, "Tag Submission and Evaluation Timetable."**