Summary of Comments, Organized By Question Number

Background

The Balance Resources and Demand SAR was posted for a third public comment period from August 20 through September 23, 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 32 sets of comments submitted via this special SAR Comment Form. The comments can be viewed in their original format at :

http://www.nerc.com/~filez/sar-approved.html

In this document, the comments have been cut and pasted under each question – thus following question one, you can view each question, the SAR DT's 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 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.

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 at 609-452-8060 or at tom.vandervort@nerc.com. You can also contact either theDirector of Standards, Tim Gallagher at 609-452-8060 or at tim.gallagher@nerc.com, or Maureen Long at 305-891-5497 or at spm@nerc.com .

Questions, Comments and their Considerations
& Latest Version of Balance Resources and Demand SAR

Comment (submitted by an industry participant):

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.

1. Do you think that CPM1, CPM2 and DCM are comprehensive enough to address the problem identified above?

Alabama Municipal Electric Authority Allegheny Power City Water, Light & Power (Springfield, IL) Duke Energy Duke Energy North America ECAR (Representing 16 companies) Entergy Nuclear Northeast Exelon FRCC Illinois Power Company Nebraska Public Power District National Grid USA PG&E Seminole Electric Cooperative, Inc. SRP	**Yes**
AEP California ISO Cinergy Corp Economist Energy Mark, Inc. ERCOT MAAC Manitoba Hydro MAPP MECS Midwest ISO Oncor Potomac Electric Power Company Southern Company Services, Inc. We Energies	**No**
Mirant Americas Energy Marketing NPCC	**Neutral**

2. If you answered "No" to Question One above, please identify specifically what changes are needed.	
Summary Consideration of Comments: Most of the comments submitted address details of how CPM1, CMP2 and DCM are calculated. In drafting this SAR, we recognized that it may be possible to improve upon the existing formulas used as the basis for these measures. The language included in the detailed description section of the SAR indicates that the Standards Drafting Team may modify the existing formulas used to calculate CMP1, CPM2 and DCM. There were also several comments indicating that this standard should include a measure for primary frequency response. This issue was posed earlier in this SAR's development, and there was no industry consensus on including a primary frequency response measure in this standard. Most of the opponents to a frequency response measure did not give a reason why it was not desired. Those who provided the reasoning for their opposition, indicated that measuring frequency response would be difficult if not impossible. We are asking the NERC Resources Subcommittee to identify ways of measuring and controlling primary frequency response. If they can identify objective measures for frequency response, they will be encouraged to submit a SAR that requires conformance with a frequency response measure.	
AEP	ACE must be brought back to zero instead of the pre-disturbance level
California ISO	An hourly measurement should be added, PROVIDING that a Standard is NOT, or will not be, adopted governing Inadvertent Flows.
Cinergy Corp	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. As stated above, 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. It would be similar to establishing a criteria today to define under what circumstances a Reliability Coordinator can require the Control Area to take action to balance. I believe also that the measures should be based upon the services being provided. The historic average frequency error was created predominantly by variable loads and the generation following that, with a much smaller contribution coming from forced outages and generation meeting fixed sales. Given that, why does it make sense to split the frequency error down the middle between a generation-only Control Area meeting 500 MW of block schedules and a Control Area providing load following /regulation services for 500 MW of load (assuming the same bias)? If the goal is to maintain an acceptable average frequency error, then the criteria should not continue to allocate the error disproportionate to the services being provided.
Duke Energy North America	The metrics themselves are sufficient. The Standards Drafting Team may consider examining the applications of the metrics (such as the setting of limits, scoring and enforcement) to ensure that the expressed concern is adequately addressed.

Economist	Setting a Frequency Response standard is more important than improving the DCS standard because primary response is more urgent than secondary response . What DCS does is to is to enforce a recovery period by assigning a "recovery obligation" for secondary response that is like the "response obligation" or bias involved in primary response. While primary response is an obligation to "share" in providing the Interconnection's response to every disturbance, the DCS "recovery obligation" is an obligation not to "share" in providing the recovery from every disturbance but rather to provide the entire recovery from just the disturbances you caused and within 15 minutes. The result is that average frequency recovery from disturbances is somewhere between five and ten minutes. Because DCS is not a "shared" obligation, "recovery obligation" is not as crucial to the Interconnection as frequency "response obligation". Moreover, it has never been scientifically explained how much DCS affects average frequency-recovery time, nor how recovery time affects CPS, nor how or even whether a DCS standard is contributing to reliability anything beyond what just CPS alone is contributing. Accordingly, because there already is a DCS standard, it is all the more absurd that there is no Frequency Response standard to enforce frequency "response obligation". Clearly deterioration in frequency response does directly affect reliability by affecting the magnitude of disturbances. Moreover CPS alone does not enforce your obligation to provide your share of primary response should you be providing excess secondary response to make up for a shortfall in performing your primary response obligation fully. The claim above that DCS fills a need to measure changes that occur over periods between one minute and ten minutes is meaningless. The claim is based on a fundamental misunderstanding of time-averages of data-samples. The purpose of a CPS2 10-minute average is not to capture data changes that occur over ten munites while CPS1 captures data changes over only 1 minute. Any changes the 10-minute sample-average detects, the 1-minute sample-average detects. Moreover, any 10-minute average in CPS1 would "slide" at one-minute increments, while the one-minute average "jumps" at one-minute increments and the 10-minute average in CPS2 "jumps" at 10-minute increments. The originator of the longer-term averages, Nasser Jaleeli, clearly stated that their purpose is ECONOMIC AND EQUITY, namely to reduce the cost of one and the same level of control by controlling to a moving-average that varies less than instantaneous changes. When enough people do that, instantaneous control actions becomes randomized relative to each other, and control cost becomes distributed equitably. That's all there is to longer-term averages. They have nothing to do with actual measurement of changes of long duration. However short the term-average you use to sample the data, you measure everything that happens over the ASSESSMENT PERIOD of CPS, which is monthly! The averaging period of each data sample must not be confused with the assessment period.

Energy Mark, Inc.	See Comment A at end of document
ERCOT	ERCOT believes a Frequency Profile standard is appropriate, especially for an Interconnection with a single Balancing Authority. However this may be an issue that needs to be addressed in a separate SAR.
ISO New England	See Comment B at end of document
MAAC	CPM2 should be replaced with a CPM60. At a minimum, this replacement would give proper acknowledgement that measures addressing transmission overloads will be addressed as part of the 'Operate within Limits' SAR. The 60 minute measure will provide a more effective standard in that a 60 minute standard can serve both the frequency-related reliability needs, and serve the need of calibraiting metered measurements with billing measurements.
Manitoba Hydro	Manitoba Hydro believes that the Standards Drafting Team should have the opportunity to investigate alternative methods of defining Control Performance to address the problems identified above. There is a definitive need to have a Frequency Response Standard to enforce frequency response obligations which affects reliability.
MAPP	DCM not should only address incidents of certain magnitude (as is the case now) but should only concern itself with recovery statistically, that is, require recovery to a certain degree but not to a "bright line" standard. If an entity has ten reportable events in given period, and they adequately resposnd to nine, this should be taken as a clear representation that they are responding to disturbances and deploying reserves. CPM MUST look at the large deviation events for non - disturbance violations of large magnitude. These events should be detected and the offending entity held to account for them. Relying on a 12-month running average (CPM1) or a monthly measurement (CPM2) is insufficient to prevent gaming (such as having 150% running average CPM1 and allowing ACE to go negative in a high-cost environment, knowing the running average will still be in compliance) in the present industry structure. This is stated realizing that market rules will likely be developed to eliminate gaming, however we should be developing standards that will ensure reliability in absense of market rules.

MECS	The existing CPS2 standard should not be rubber stamped into the new CPM2 standard. The existing allocation of Lsub10 is done using the square root of system size based on the assumption of the independence (no correlation) of ACE in different areas in spite of the obvious correlations including time of day, weather and frequency bias obligations. Our experience of operating a single NERC Control Area with sub areas has resulted in some periods of reported noncompliance to the existing CPS2 standard even though the sub areas, if allowed to report their individual CPS2 performance, would have been easily compliant. If future industry trends produce larger Control Areas this phenomenon would affect more systems. DCM "defined period" needs to be specifically stated (i.e. 15 minutes from the start of the event). This is necessary to assure consistency and eliminate open interpretation as to what "quickly returns" truly means.
Midwest ISO	There have been a few alternatives discussed in the NERC JIITF and the NERC Resources Subcommittee that would work. An hourly average CPS1 metric would be superior to the combination of CPM2 and DCM. The other JIITF options would work, however, it would still be possible to have wide variation + and – during the hour as long as the net is small and compliance would be met. An hourly CPS1 would capture intra-hour extremes. However, without a way to easily validate data, any standard is deficient.
Oncor	A frequency profile standard should be added for single BA Interconnections
Potomac Electric Power Company	There should be a 60 minute standard that encourages balanced ACE within the normal billing cycles, There is a linkage between ACE as a reliability measure and the cost of energy and ancillary services needed to correct it that cannot be overlooked.
Southern Company Services	There is a need for at least one and perhaps two measurements to capture short term behavior of ACE. The behaviors that need to be captured are 1) short term ACE variations that are not captured by DCM (i.e., that are smaller than reportable) or L10 (i.e., that occur less than ten percent of the time) and 2) frequency response, including both load frequency response and turbine governor response. A short term calculation similar to CPS1, but performed over a shorter time frame (such as the hourly CPS proposed by Terry Bilke of MISO) would cover the short term ACE variations. A frequency response standard (FRS) such as that proposed by the Resources Subcommittee is needed to cover frequency response. It is difficult for me to see how we can get by without some form of frequency response standard (although the proposed standard is obviously not the only one possible).
SRP	If CPM1 and CPM2 are reported as "compliant" during the problem scenarios listed above, the CPM1 and CPM2 reporting for the responsible entities must be in error.

We Energies	This Standard will apply to the Balancing Authority, not to the existing Control Areas, The BA will likely be the RTO/ITP which will encompass many existing control areas and there will likely be few BA's to achieve the diversity of control with. Key thoughts here is that ACE equation remains as we know it today and the responsibility for interconnection frequency response moves to the ITP's. CPM1 measurement (calculation)is fine but the time frame needs to be shortened and allowable performance needs to be higher to achieve the same frequency profile. CPM2 is probably o.k. as the BA's get larger the requirement naturally gets more stringent. DCM will likely not need to exist, as long as there is a "trigger" in NERC Standards that would establish an "Operating Reserve" requirement and CPM1 & 2 cover the control requirements. The local imbalance markets and rules within the ITP should generate the commercial arrangements to meet the Reserve and Control requirements.

3. Is there a reliability-related reason for including Time Error Correction in this SAR?	
City Water, Light & Power (Springfield, IL) Duke Energy Economist Exelon ISO New England MECS Midwest ISO SRP WE Energies	**Yes**
AEP Alabama Municipal Electric Authority Allegheny Power California ISO Cinergy Corp Duke Energy North America ECAR (Representing 16 companies) Energy Mark Inc ERCOT FRCC Illinois Power Company MAAC Manitoba Hydro MAPP Nebraska Public Power District Mirant Americas Energy Marketing National Grid USA Oncor PG&E Potomac Electric Power Company Seminole Electric Cooperative, Inc. Southern Company Services NPCC	**No**
Entergy Nuclear Northeast	**Neutral**

4. If you answered "Yes" to Queston 3 above, identify specifically what the reliability-related reason for time error correction is.	
Summary Consideration of Comments: Although several entities indicated they would like to continue with time error correction, most of the reasons provided indicated that time error is a measure of performance, rather than a performance goal. We will forward these comments to the Standards Drafting Team assigned to work on the details of this standard.	
City Water, Light & Power	It is the only long-term way of verifying that generation and frequency are in balance.
Duke Energy	Customers have an expectation that frequency be maintained within a narrow tolerance of scheduled frequency. In use customer processes have been impacted by significant time errors. Therefore, the ability to monitor and correct time error is a reliability issue. We recognize that the correction of the accumulated time error may be accomplished thorough a commercial product.
Duke Energy North America	Time Error correction itself is not a reliability related issue that needs to be specifically addressed in the SAR. However, time error could be a symptom of poor performance of entities in maintaining the required frequency profile.
Economist	See Comment C at the end of this document
Exelon	Exelon believes it necessary to maintain some control of time error, however we believe the limits should be "loosened" (up to 1 minute) from current standards.
ISO New England	Accuracy of frequency control performance and consistency of time throughout the Interconnection.
MECS	Although TEC is not a reliability issue in itself, it can have reliability impacts if not administered properly. A slow TEC during a period with depressed frequency can further compound the problem with potentially serious effects. This standard should include the reference to TEC negative impacts with guidelines for suspension, if actively in effect, and cancellation if not currently in effect but scheduled to begin prior to the expected recovery of a depressed frequency.

Midwest ISO	The priority for a TEC standard is not has high as for other control. Any penalties should be minimal (just paper sanctions). However, I believe there still is a need. One thing we have to realize is that without the requirement for saving common data at each control area so that performance can be verified, there is almost no way to validate that performance is as stated. The error could be innocent. Time is a solid and easy to understand indicator of the general "health" of the interconnection. Repeated time corrections are an indication to look deeper. Start-stop trigger bands could be widened to minimize artificial intervention into the frequency profile. Many people say that there would be no impact to industry should time control be eliminated. But the reality is nobody knows for sure what would happen. There almost surely would be no major impacts, but what is the need or benefit from completely eliminating time control? *Consideration:* We will forward this comment to the Director of Compliance and recommend that he add the elimination of Time Error Correction to the list of elements to be included in field testing. This should provide us with some measure of the impact of the elimination of time error correction.
SRP	The frequency of interconnected bulk electric systems shall be controlled within defined limits through the balancing of electric supply and demand. Time Error is a measure of interconnection balance. Instantaneous time error and inadvertant (or instantaneous NSI deviation) are reliability issues although it is reasonable to view end of hour accumulations as commercial issues as the FERC SMD NOPR has done. As far as a Balancing Authority is concerned, operating off frequency or off schedule results in unscheduled power flows that can be a significant issue on some transmission paths.
We Energies	This standard will require a scheduled frequency for the interconnection, this scheduled frequency should reflect a frequency profile that will maintain average system frequency at design specifications over time. In order to accomplish this frequency diviations will move the scheduled frequency to correct for such deviations.

5. Should the SAR DT allow the Standards Drafting Team to define "frequency profile" during the next phase in the standard development process?	
AEP Alabama Municipal Electric Authority Allegheny Power City Water, Light & Power (Springfield, IL) Duke Energy ECAR (Representing 16 companies) Economist Entergy Nuclear Northeast ERCOT FRCC Illinois Power Company ISO New England MAAC Manitoba Hydro MAPP MECS Mirant Americas Energy Marketing Nebraska Public Power District Oncor Potomac Electric Power Company Seminole Electric Cooperative, Inc. Southern Company Services We Energies	**Yes**
California ISO Exelon National Grid USA PG&E SRP	**No**
Cinergy Corp Energy Mark Inc Duke Energy North America Midwest ISO NPCC	**Neutral**

6. If you think the SAR DT should define "frequency profile," please recommended definition or the parameters to include in the definition.	
Summary Consideration of Comments: The consensus of comments support the Standards Drafting Team defining "frequency profile." This definition should not preclude each interconnection from establishing the boundaries of that profile. Several commenters presented parameters for the Standards DT to consider and these comments will be forwarded to the Standards DT.	
AEP	The frequency profile should have two boundaries. The first should bound real-time frequency to a short-term threshold which is considered to be safe for a short period of time (like a spike which occurs with a unit trip). The second bound should be a safe, longer-term operating frequency, where the grid could withstand a first contingency situation. Also, cover the time error as part of the frequency profile.
California ISO	The "frequency Profiles" have already been defined in each interconnection during the establishment of CPS criteria.
Cinergy Corp	I believe in either case that the "frequency profile" should be agreed upon by the industry.
City Water, Light & Power	Since it is undefined and it is unclear what it means, it needs to be defined. The duration of the time period being considered needs to be included.
ECAR (Representing 16 companies)	The SAR drafting team should define "frequency profile" but the definition should not be automatically approved. The definition should be posted for comments and should go through due process before being approved.
Economist	Targeted/allowed frequency range [epsilon in the CPS1 equation]
Energy Mark Inc	It does not matter which group defines "frequency profile" as long a the definition is developed properly. The term "frequency profile" exists because some past decisions concerning reliability limits for frequency were based on historic frequency performance as defined by a historic frequency profile. This path was chosen because it was assumed that historic reliability performance was adequate and that if historic frequency performance was maintained then historic reliability performance would also be maintained. This is akin to saying we have always done it this way. The correct way to develop a "frequency profile" is to determine the specific failure modes for the interconnection resulting from off-schedule frequency operation. This is the only way to insure that the "frequency profile" used for reliability purposes is actually based on reliability requirements and not some past practice that is not related to reliability.
Exelon	The "frequency profile" should be consistent with its current use for CPS. The limiting frequency profile should be the RMS of one minute average frequency error values.

Manitoba Hydro	The frequency profile of the interconnected transmission system should be defined to minimize the system frequency deviation by ensuring that each Control Area operates to keep its generation and load balanced with minimal " +" or "-" error at all time. When the FERC SMD environment is implemented, the ITP/RTO will be responsible to ensure that adequate resources are in place to minimize this hourly imbalance. This should eliminate the requirement for Time Error Correction. Until then the Time Error Correction should be maintained.
MAPP	Ideally, a frequency profile should define a deviation from schedule over a short term and a long term. MAPP would recommend a 1 minute interval and a 1 hour interval. Suggested criteria for these intervals could be 18 mHz for the 1 minute interval and 6 mHz for the hour interval.MAPP recognizes that different intervals and/or criteria may be developed, however an interval less than one minute would not be meaningful.
Midwest ISO	The RMS value of the one-minute (or other time period) averages of frequency deviation from 60 Hz
Potomac Electric Power Company	The Control Performance Standards support an agreed upon frequency profile measured by mean and standard deviation. The process should start with those measures from current (historic) periods.
Seminole Electric Cooperative, Inc.	Should be based on historical performance in all 3 interconnections. An objective should be elimination of necessary waivers the Interconnections.
SRP	It should be stated (in the SAR) that each interconnection shall determine the frequency profile.

7. To ensure relevant "Regional Differences" to the "Balancing Resources and Demand" SAR are identified, please note the "Regional Differences" (beyond ERCOT and WECC) that you are aware of:	
Summary Consideration of Comments: **The SAR DT requested specific "Regional Differences" in order to identify and include them in the initial SAR. The specific regional differences that have been noted have been included in the SAR. If other regional differences are noted as the standard is developed, these should be submitted to the Standards Drafting Team assigned to work on this standard. Interested industry participants have the right to submit comments to indicate whether or not a standard should include a specific regional difference. Only Regional Differences that receive industry consensus will be included in the standard.**	
Regional Differences	
AEP	The SAR Drafting Team or the Standards Drafting Team should coordinate with NERC to have studies performed to identify and justify relevant differences
Alabama Municipal Electric Authority	Time zones differences and customer load shapes (municipal vs cooperative) result in differing demand peaks and can cause none optimal use of resources. There is no Control Area to Control Area planning for resources and demand.
Cinergy	The Midwest region such as ECAR is abundant in non-conforming loads. Though it could be argued that the criteria should not be "relaxed" for Balancing Authorities responsible for meeting the load following requirements of such loads, it can be argued that the frequency error will get progressively worse if the criteria is not changed to recognize differences in the services being provided by generation. ***Consideration:*** Non-conforming loads in ECAR will be added to the list of Regional Differences highlighted in this SAR.
Duke Energy	There are no needs for Regional Differences within the Eastern Interconnection. Reserve groups rely on other Control Areas through bilateral contract obligations to meet DCM that are consistent with the existing requirements in the Eastern Interconnection. These bilateral relations are important and needed to meet reserve obligations. Duke believes that these bilateral obligations will continue to be used under the requirements of the new Balance and Resource Demand SAR. The **measure** should be developed in such a manner to allow these obligations to be used for meeting the requirements of the **standard**.
Duke Energy North America	ERCOT is a single control area within its own interconnection. ***Consideration:*** In the "Regional Differences" section of this SAR, there is a note indicating that CPM2 would not apply to ERCOT..

ECAR (Representing 16 companies)	Many of the ECAR companies serve 'non-conforming loads', which have large cyclical swinging loads. The CPS1 and CPS2 performance criteria should be modified for those Control Areas in ECAR with large cyclical swinging loads. These Control Areas should not be required to meet the same CPS1 and CPS2 performance criteria as those Control Areas that have little or no 'non-conforming loads'. ***Consideration:*** Non-conforming loads in ECAR will be added to the list of Regional Differences highlighted in this SAR..
MAAC	The fact that two major regions covering more than one half of NERC require waivers, begs the question whether or not the Standard being requested is truly a core reliability standard. The SAR DT would do well to respond to the question, can the proposed standard be redrafted to cover the frequency-related issues common to all regions and interconnections? The original concept of the SAR was to respect the profile of frequencies 'experienced' on each interconnection. Both ERCOT and WECC have some frequency history. We should be able to agree that the history should at least be maintained (if not improved). If the proposed measuements are insufficient then we should agree on the profile concept and allow the Standards Drafting Team develop measures to reflect the level of performance desired (i.e. the profile mandated by this SAR).
Midwest ISO	The Maritimes sometimes operates separately from the Eastern Interconnection.
Oncor	ERCOT is both Region and Interconnection
Southern Company Services	Reserve Sharing Groups (RSGs) are currently common in many regions, but do not function exactly the same in all regions. It is difficult to say if this is a regional difference or just a lack of standardization, but it does need to be addressed. In addition, dynamic scheduling and pseudo ties (dynamic transfers) are handled differently in different regions (or at least in different implementations). There is a group looking at these dynamic transfers currently. This effort should be adopted into the SAR process. ***Consideration:*** You can submit a specific request to have a Regional Difference added to the standard. While it is best to do this during the SAR development process, comments can be submitted, requesting the addition of Regional Differences during the standard development process.
NPCC	NPCC also requires compliance with Operating Reserve Requirements. The NPCC A-06 Document, "Operating Reserve Criteria," which indicates a Regional Difference is attached. ***Consideration:*** Operating Reserve requirements in NPCC will be added to the list of Regional Differences highlighted in this SAR..

8. To ensure relevant "Interconnection Differences" to the "Balancing Resources and Demand" SAR are identified, please note the "Interconnection Differences" that you are aware of:	
Summary Consideration of Comments: The SAR DT requested specific "Interconnection Differences" in order to identify and include them in the initial SAR. An Interconnection Difference noted was for ERCOT.	
AEP	The SAR Drafting Team or the Standards Drafting Team should coordinate with NERC to have studies performed to identify and justify relevant differences
Alabama Municipal Electric Authority	There are no standards or uniformity in how transmission capacity is calculated by each interface. There may be capacity available on one side of an interface but not on the other side of the same interface.
Duke Energy	Although the equations are the same for CPS1 and CPS2 for all interconnections, the epsilon constants used in the equations are different for the interconnections. ***Consideration:*** Epsilon 1 will be added to each Interconnection Difference.
Duke Energy North America	ERCOT consists of only one control area. ***Consideration:*** CPM2 would not apply to ERCOT will be added as an Interconnection Difference.
ERCOT	Single Balancing Authority vs Multiple.
Oncor	This is an ERCOT Interconnection Difference
MAPP	Only epsilon 1 (i.e. freq profile) ***Consideration:*** Epsilon 1 will be added to each Interconnection Difference.
Midwest ISO	CPS2 (Now CPM2) does not apply to a single control area interconnection such as ERCOT. ***Consideration:*** CPM2 would not apply to ERCOT is currently a Regional Difference and will be added as an Interconnection Diffference.
We Energies	Each interconnection should determine it's own frequency profile.

Other Comments on SAR	
Cinergy	In addition, I believe it is necessary to make sure that the Balancing Authorities are held to the correct implementation of the information that makes up the ACE. Maintaining accurate metering and implementing scheduled interchange correctly are two examples where the ACE can look good when the frequency is still impacted. Likewise the SAR needs to better define reporting requirements across entities that can potentially "swap" ACE through dynamic schedules and pseudo-ties to meet DCS compliance for example. Consideration: We will forward your comment to the Standards Drafting Team. They will need to develop effective tools to measure the performance objectives.
PSE&G	The question "Does the proposed Standards comply with all the Market Interface Principles" cannot be answered until the Standard has been written. The actual content of the standard could violate Market Interface Principles # 2 and # 4. Remove the 'Yes" to this question and replace it with TBD. Consideration: The standards development process requires that the Market Interface Principles be reviewed and considered before the Standards Authorization Committee (SAC) approves the initial posting of a SAR. This is intended to prohibit the development of standards that will have an unnecessary adverse impact on markets. If, during the standards development process, a SAR or draft standard looks as though it were going to have an unnecessary adverse impact on markets, you should submit a specific comment highlighting why you feel this way. During each of its meetings, the SAC asks if there have been any challenges to the integrity of the standards development process, and such a comment would be brought forward to the SAC for their consideration. If the SAC reviewed the comment and felt that it were justified, the SAC has the authority to take corrective action by directing that the SAR be revised, withdrawn or by rejecting the SAR. If the actions of the SAC don't reslove the conflict, there is an appeals process that can be used to highlight the conflict and bring the conflict to resolution. The appeals process is described in the Standards Process Manual, page 23.
NPCC	NPCC A-06 defines the amount of operating reserve to be carried, the timeframe in which the reserve needs to e replenished and provides the timeframe in which this is to be accomplished. Consideration: NPCC's request for a Regional Difference has been noted and is listed in the Regional Differences section of the SAR.

Comment A (Response to Question 2 from Energy Mark, Inc.)

The comment as submitted by an industry participant is based on an incorrect interpretation of the functions of CPS1, CPS2 and DCS. As one who helped NERC develop the CPS control criteria, I will address individually in the following paragraphs a number of issues raised by the comment.

"There is a need for a standard that fills the time gap between CPS1 and CPS2." There is no time gap between CPS1 and CPS2 measurements. There is no gap because CPS1 and CPS2 measure different reliability contributions.

CPS1 samples ACE over consecutive one-minute intervals and multiplies the average ACE times the average frequency error of the interconnection sampled over the same one-minute interval in order to weight the individual ACE by the interconnection's frequency error. This weighted ACE (CPS1 measure) indicates the individual Balancing Authorities contribution to the total interconnection frequency error. The CPS1 measure weights, over a long assessment period of consecutive one-minute intervals, each Balancing Authority's contribution to interconnection frequency error. This weighted contribution is then compared to the Balancing Authority's "bias" share of the square of the frequency error limit for the interconnection, epsilon. If the Balancing Authority's frequency-error-weighted contribution is less than the Balancing Authority's "bias" share of epsilon squared, it passes CPS1.

CPS2 samples ACE over consecutive ten-minute intervals but does not weight it by interconnection frequency error. CPS2 measures the possible contribution of an ACE error to transmission flows that could harm transmission reliability. In other words, CPS2 imposes an historic limit on the size (L10) and duration (10-minutes) of unscheduled transmission flows due to ACE error All of the data on frequency error, and resource and demand imbalance sampled in the CPS2 measure has been sampled in the CPS1 measure. Therefore,

"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." The objective of DCS is not to restore ACE to zero. The objective of DCS is to determine whether or not a Balancing Authority is meeting its Secondary Control Operating Reserve obligations. DCS is not intended to provide any measure of resource and demand balance as measured by ACE. DCS only assures that a Balancing Authority carries sufficient reserve to manage ACE in compliance with CPS1, not how well or badly the Balancing Authority is actually using the reserve to manage ACE in compliance with CPS1. The restoration of ACE for a subset of the DCS measurements is simply a logical consequence of recovery from the respective disturbances.

Could the gap result from the fact that DCS measures only sufficient reserve availability for Secondary Frequency Control, rather than sufficient control action to restore frequency to schedule following a disturbance? The adequacy of these reserves for secondary frequency control is already measured on average by CPS1. But before these reserves can be applied, other balancing resources must be applied automatically to limit the frequency error resulting from the disturbance imbalance. If these other balancing resources (known as governor and load frequency response) are insufficient to limit the frequency error to a reliable operating range, the interconnection will fail before the Operating Reserves measured by DCS can be applied. That's how there's a disconnect between DCS and CPS. These "primary-response" resources are not measured under the current Policy 1 or by any suggested measure in the SAR, while whatever DCS can measure is already captured in CPS1.

The gap needing to be filled is the failure of current policies and of the SAR to insure that not only are there sufficient reserves available to recover from a disturbance, but also that those reserves are

carried and operated in such a manner that a disturbance will not be allowed to grow so rapidly that the interconnection fails before there is an opportunity to use the reserves. This was and continues to be the reason why a Frequency Response Measure was included in the original SAR. Ignoring this part of the problem fails to reduce the scope of the SAR because a measure of Frequency Response is already included in the ACE equation anyway and for any measure that includes ACE to truly be effective, it must also measure and assign responsibility for Frequency Response. This is truly a question of pay now or pay later. The issue cannot be avoided in the SAR because that inevitably sets the SAR up for failure to achieve its purpose.

"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 deficiency does not fit the definition of a "reportable event"." Both CPS1 and CPS2 are designed to catch this manner of operation. CPS1 indicates the frequency-error weighted contribution by this method of operation to interconnection frequency error and CPS1 limits the damage the Balancing Authority does to reliability/frequency by off-schedule operation. CPS2 is intended to limit the number of 10-minute intervals during which a Balancing Authority operates with ACE beyond its L10 flow limit. However, CPS2 does not restrict CPS2 violations from occurring adjacent to each other in time; it limits only the total number of CPS2 violations allowed over a monthly interval.

"The way the DCS is crafted, it is acceptable 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." It is impossible to determine where the commenter thinks the gap is in the current measures. If the commenter is requesting that ACE be returned to zero every ten minutes, then the problem is associated with the CPS2 requirement and relates to the flows on the transmission system. Methods have already been developed to manage unscheduled transmission flows by redispatch that is proving to be a better method to manage those flows than the use of a limit like CPS2. Redispatch is a better method because resources have to be expended only when the unscheduled flow is in the constrained direction, or only about one half of the time. This allows redispatch to accomplish the same reliability at a much lower cost. As redispatch is applied to limit these unscheduled flows, the need for CPS2 as a measure will decline and eventually be eliminated altogether. If the comment is intended to address the problem of time-adjacent CPS2 violations, still the gap cannot be filled efficiently with additional restrictions on the limits associated with balancing resources and demand, but must be addressed in other SARs associated with limiting transmission flows.

Summary Conclusions:

There are only two possible gaps in the measurements.

The first possible gap is that there may be requirements for reliability that occur in less than the one-minute measurement interval defined for the CPS1 measure. This gap occurs because DCS does not effectively measure all of the reserves required for reliable interconnection operation, specifically frequency responsive reserves. DCS measures only reserves deployed in Secondary Frequency Control. There are no gaps in frequency measurements greater than 1-minute because the longer interval data consists of the same 1-minute data used for interconnection frequency control, and resource and demand balance. Filling any gap here requires rather that the SAR include a Frequency Response Measure.

There is a possible gap in the CPS2 measurement because it does not limit failures from occurring in adjacent time-intervals. This gap can be better filled with other SARs that address unscheduled transmission flows directly through redispatch. The balancing required by the CPS2 measure can be more effectively included in other SARs.

This would result in a SAR with the following:

- CPM1
- DCS that includes the equivalent of FRM
- CPM2 that would decline in importance as other SARs assume flow-control responsibilities.

Comment B (Response to Question 2 from ISO New England)

Simply renaming CPS1, CPS2, and DCS will not serve the industry well. A systematic review of the shortcomings of each measure by the NERC Resources Subcommittee would serve as a very useful input to the SAR process. A review of the more obvious shortcomings in the three existing standards is included herein.

CPS 1

1. There is an inherent and not well-advertised problem with CPS 1. If the frequency target is set to the value that is desired, and that desire is in fact achieved, about half of the members of an Interconnection will be deemed non-compliant (CPS 1 <100%). But if the target (Є1) is set higher than the historical value (as has been done for the Eastern Interconnection), the short term "happy" result of universal compliance (as was achieved for the Eastern Interconnection) will ultimately result (after control areas detune their AGC systems directly or indirectly) in a frequency profile that is not what is desired (as we have seen on the Eastern Interconnection). What we have observed is CPS 1 scores in the 160's become 140's over time, but very few control areas ever become non-compliant in the present implementation, and the loss of frequency performance is not explained plausibly by the behavior of those found to be non-compliant. The change in the median CPS 1 score over time only indicates an uncalibrated trend in frequency performance degradation.

2. The one year running average used by CPS 1 is far too long to effectively diagnose compliance problems.

3. CPS 1 does not recognize time of day dependencies, and an hourly version of it needs to be considered. Good performance in the hours of easy control mask deficiencies in the transitional hours, which have shown up glaringly in recent times due to coincident market forces. Coincidence in time of day effects challenges the much-overstated theoretical purity of CPS 1.

4. The need for a CPS 1 – 10 minute (or longer period) needs to be addressed to keep the n minute frequency deviation averages closer to the theoretical Jaleeli curve (to bound the one-minute vs. the ten-minute averages).

CPS 2

1. The L10 limits were developed based on frequency needs and applied to a transmission-related issue. Resultant L10 values are typically 50 to 100% greater than the Ld limits used with the defunct criterion A2. More through good fortune than careful planning, the expansion of the limit on ten minute integrated ACE values has not resulted in significant problems for the Eastern Interconnection. CPS 2 is the effective constraint on most control area's detuning of their AGC performance, and probably a significant reduction in regulation costs has been achieved industry wide without any obvious loss of reliability. An alternative methodology to limit large unscheduled net flows out of a control area, however, will probably be very difficult to develop theoretically.

2. While CPS 2's compliance horizon of one month is far better than CPS 1's annual horizon, it too could use some time of day constraints to address the coincidence among control areas that is being observed on a daily basis.

3. The pass/fail nature of CPS 2 assigns equal weight to the violation of L10 by 1 MW or 300 MW, for example. As a result, when CPS 2 is coupled with the high reporting threshold of the DCS, a control area can drag for extended periods for "medium sized" contingencies below its DCS reporting threshold with impunity as long as the monthly CPS 2 score stays above 90%. An adjusted CPS 2 scoring mechanism whose penalty is proportional to the magnitude of the violation above L10 could plug the gap between CPS 2 and DCS.

4. Currently, the penalty imposed by NERC for CPS 2 compliance failure is inadequate. The pragmatic deterrents in place to avoid ignoring CPS 2 compliance are operator and control area pride in a job well done, and self-imposed corporate goals.

DCS

1. A fifteen minute recovery has shown to be desirable on a theoretical basis and achievable on an empirical basis.

2. Over time, as the NERC Resources Subcommittee has removed compounding of penalties, the DCS penalties on their own seem to be ineffective. Examples can be developed which demonstrate the economic benefit of covering only the second largest contingency when the first contingency loss is much larger than the second contingency loss. The pragmatic deterrents in place to avoid ignoring DCS compliance are operator and control area pride in a job well done, and self-imposed corporate goals.

3. The 80% of first contingency loss reporting threshold needs careful review, given the several years of operating experience we have with the DCS. See CPS 2 comment 3 above. Some control areas often have consecutive quarters with 0 or 1 reportable event per quarter.

Comment C (Response to Question 4 from Economist)

A Standard to define & measure Inadvertent Interchange needs to be included, extending beyond just a Time Error correction of accumulated inadvertent imbalances. Time Error correction by itself is not a reliability issue but just a commercial service. Inadvertent Interchange is a reliability issue because Inadvertent Interchange occurs whenever a control area's ACE is a greater share of the Interconnection's ACE than the control area's obligation share of the Interconnection's frequency response to the Interconnection's ACE. Inadvertent Interchange is the result of one control area's sharing in providing the frequency response to another control area's ACE. Since controlling ACE is a reliability issue, defining and measuring Inadvertent Interchange is a reliability issue. In fact it is only when Inadvertent Interchange is non-existent that ACE itself is not an Interconnection reliability issue because each control area is fully responding to its own ACE.

What the FERC NOPR defines as Inadvertent Imbalance is the energy and transmission component of Inadvertent Interchange, but not the frequency component. The FERC NOPR is a Notice, not a Ruling; emphasize the "N", not the "R". FERC takes reliability guidance from NERC. NERC does not take reliability guidance from FERC. Accordingly, NERC is not bound by FERC decisions on what does or does not constitute a reliability issue, nor is NERC constrained by FERC's failure to properly define a reliability product. That is a sole prerogative of NERC and FERC rulings or notices must ultimately comply with reliability standards, definitions and measures that NERC develops regardless of uninformed declarations by FERC.

A reliability issue may also be a commercial issue coming under FERC's purview. Reliability and commercial are neither mutually exclusive nor identical. Reliability issues have commercial aspects. A market may have reliability products: as reliability, NERC decides how they are defined and measured, but not priced. Absent a market, NERC may recommend a penalty &/or reward, subject to FERC ruling on reasonableness. FERC may declare Inadvertent Imbalance as a commercial issue, but it has no authority by itself to declare that Inadvertent Interchange is NOT a reliability issue. NERC needs to define Inadvertent Interchange because the commercial aspect of Inadvertent Interchange affects reliability. Only NERC can do that. To state that NERC cannot decide something is a reliability issue because FERC has said it isn't a reliability issue is a logical fallacy called "begging the question".

FERC requires a Balancing Authority to be non-profit partly because NERC did not solve the problem of the commercial incentives to control areas to incur Inadvertent Interchange for free and this increased Inadvertent Interchange and therefore ACE and therefore jeopardized reliability. NERC's past failure to properly define Inadvertent Interchange for pricing purposes is no reason to prohibit NERC from properly defining it in the future. Again, fallacious circular reasoning. There is less reason for FERC to keep Balancing Authorities non-profit once NERC properly defines Inadvertent Interchange as a reliability product in order for the market to price it.

Title of Proposed Standard	Balance Resources and Demand
Request Date	January 28, 2002
ID	BAL_RES_&_DEMND_01_03
Authorized for 1st posting	February 5, 2002
Authorized for development	

SAR Requestor Information		**SAR Type** (Put an 'x' in front of one of these selections)	
Name James Byrd (Albert DiCaprio as substitute for Mr. Byrd)		x	New Standard
Primary Contact Albert DiCaprio			Revision to existing Standard
Phone 610 666-8854	Fax 610 666-4282		Withdrawal of existing Standard [1]
e-mail dicapram@pjm.com			Emergency Action

Purpose/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 frequency-related cascading collapse of the interconnected grid.

Brief Description

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 have the authority to monitor system frequency and have the authority to direct actions (to control frequency) that include load shedding.

[1] Requests to Withdraw an existing Organization Standard only require that this page be completed.

Reliability Functions

The Standard will Apply to the Following Functions *(Put an 'X' in front of each one that applies)*		
x	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

Reliability and Market Interface Principles

Applicable Reliability Principles *(Put an 'x in front of all that apply)*	
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
x	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
x	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented
x	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems
x	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified and have the responsibility and authority to implement actions
x	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	

Detailed Description

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.)

Related Standards

Standard No.	Explanation

Related SARs

SAR ID	Explanation
COOR INTERCHNG_01_01	The "Coordinate Interchange" SAR addresses the coordination of data exchange associated with transactions and may have some requirements that interface with the "Balance Resources and Demand" SAR.
FACILITY_RATINGS_01_01	The "Determine Facility Ratings, Operating Limits, and Transfer Capabilities" SAR identifies how operating limits are established. The operating limits established within this proposed standard will interface with the performance standards within the "Balance Resources and Demand" SAR.
OPER_WITHN_LMTS_01_01	The "Monitor and Assess Short Term Reliability, Operate Within Limits" SAR identifies requirements for operating within limits in real time and may interface with some of the requirements for the "Balance Resources and Demand" SAR.
ABNML_&_EM_COND_01_01	The "Prepare for and Respond to Abnormal or Emergency Conditions" SAR identifies requirements for recognizing and responding to emergency conditions and may interface with some of the requirements for the "Balance Resources and Demand" SAR.

Regional Differences

Region	Explanation
ECAR	ECAR has Non-conforming Loads which need to be considered
ERCOT	CPM2 will not apply to ERCOT.
FRCC	none
MAAC	none
MAIN	none
MAPP	none
NPCC	NPCC requires compliance with Operating Reserve requirements
SERC	none
SPP	none
WECC	WECC requires compliance with Operating Reserve requirements

Interconnection Differences

Interconnection	Explanation
Eastern	Epsilon 1
Western	Epsilon 1
ERCOT	Epsilon 1, CPM2 will not apply to ERCOT

Additional details of the implementation plan will be developed as the standard is drafted

Implementation Plan (Preliminary)

Description
The following sections of Operating Policies should be retired when this standard is implemented: Policy 1 – Generation Control and Performance Section D. Time Control Section E. Performance Standard Section G. Control Surveys Requirement 1.3 CPS and DCS surveys Appendix 1D Time Error Correction Procedures Performance Standard Training Document C. Calculation of Compliance D. Survey Procedures

Team Assignments

"Balancing Resources and Demand" SAR Drafting Team:

Chairman: Carl Monroe

Secretary: Tom Vandervort

Requestor: Jim Byrd (Albert DiCaprio as substitute)

Industry Representatives:

Stan Kopman	Bob Dintelman
Bill Blevins	Gary Jackson
Al DiCaprio	Mark Henry