NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2009 Bulk Power System Reliability Performance Metric Recommendations

to ensure the reliability of the bulk power system

September 4, 2009

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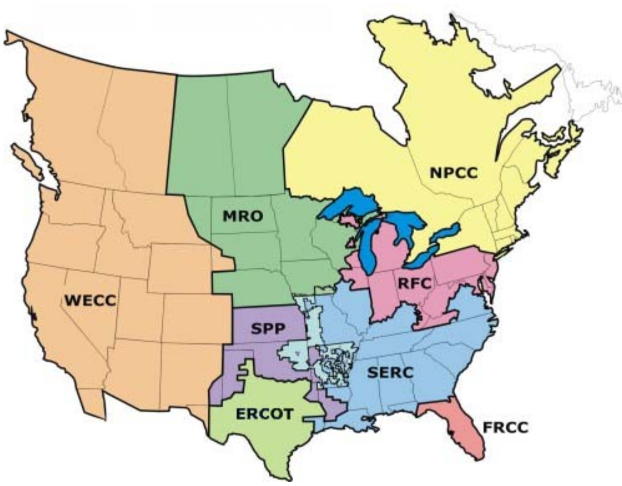
NERC's Mission

The North American Electric Reliability Corporation (NERC) is an international regulatory authority for reliability of the bulk power system in North America. NERC develops and enforces Reliability Standards; assesses adequacy annually via a 10-year forecast and winter and summer forecasts; monitors the bulk power system; and educates, trains, and certifies industry personnel. NERC is a self-regulatory organization, subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.[1]

NERC assesses and reports on the reliability and adequacy of the North American bulk power system divided into the eight Regional Areas as shown on the map below (See Table A).[2] The users, owners, and operators of the bulk power system within these areas account for virtually all the electricity supplied in the U.S., Canada, and a portion of Baja California Norte, México.



Note: *The highlighted area between SPP and SERC denotes overlapping regional area boundaries: For example, some load serving entities participate in one region and their associated transmission owner/operators in another.*

Table A: NERC Regional Entities

ERCOT Electric Reliability Council of Texas	**RFC** Reliability*First* Corporation
FRCC Florida Reliability Coordinating Council	**SERC** SERC Reliability Corporation
MRO Midwest Reliability Organization	**SPP** Southwest Power Pool, Incorporated
NPCC Northeast Power Coordinating Council, Inc.	**WECC** Western Electricity Coordinating Council

1 As of June 18, 2007, the U.S. Federal Energy Regulatory Commission (FERC) granted NERC the legal authority to enforce Reliability Standards with all U.S. users, owners, and operators of the bulk power system, and made compliance with those standards mandatory and enforceable. Reliability Standards are also mandatory and enforceable in Ontario and New Brunswick, and NERC is seeking to achieve comparable results in the other Canadian provinces. NERC will seek recognition in Mexico once necessary legislation is adopted.

2 Note ERCOT and SPP are tasked with performing reliability self-assessments as they are regional planning and operating organizations. SPP-RE (SPP – Regional Entity) and TRE (Texas Regional Entity) are functional entities to whom NERC delegates certain compliance monitoring and enforcement authorities.

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Executive Summary

The NERC Planning and Operating Committees have promoted the development of performance metrics for North America's Bulk Power System (BPS) through the formation of the Reliability Metric Working Group (RMWG). The intent of this program is to provide a slate of metrics, which can yield an overall assessment of the North American Bulk Power System reliability. The RMWG's charge is to do so within the context of the "Adequate Level of Reliability" (ALR) framework, as set out in the December 2007 report *Definition of "Adequate Level of Reliability"*[3]. The RMWG scope approved by the Planning Committee (PC) and Operating Committee (OC) can be found in Appendix 2.

The RMWG developed a decision making and continual improvement process and began to apply it to the myriad field of metric possibilities. It is a process that embraces continuous improvement. As a NERC stakeholder body, the RMWG is carrying out the duties outlined in its scope utilizing the principles espoused in the creation of the ERO; namely the application of industry expertise and use of technical judgment in the ways described in this report. There is no perfect metric for measuring all reliability activities or performance. Knowledgeable individuals can disagree with the construction, and availability or accuracy of data along with the means of presenting this information. However, the preponderance of trends related by a set of metrics, as a whole, can provide vital insights into bulk power system reliability. In order to make progress the usefulness of individual proposed metrics must be balanced against waiting for "better" ideas.

This report includes a recommendation to implement, or begin data collection in support of nine identifiable and defined metrics. Each metric has a specification describing the metric, its data sources and other attributes necessary for successful implementation. There are nine recommended metrics, listed in Figure ES-1, which cover a portion of the ALR concepts.

Extensive outreach to sixteen stakeholder groups is part of the work plan, thirteen of which are technical subgroups of the NERC Planning and Operating Committees. Nine of these outreach efforts have been initiated with at least one meeting. This activity has resulted in an initial recommended pool of eleven metrics, which are under active consideration. In fact, some of these submittals have influenced the discussion regarding the metrics recommended for approval. The three-year work plan for the RMWG outlines a series of metrics proposals reviewed at regular intervals, of which this is the second. The first proposal presented in 2008 consisted of one metric which was not approved by the Planning Committee.

The RMWG has developed a continual improvement process so NERC Stakeholders can propose metrics for consideration. Each proposed metric is considered through an ongoing evaluation process.

[3] Detailed definitions of ALR are available at http://www.nerc.com/docs/pc/Definition-of-ALR-approved-at-Dec-07-OC-PC-mtgs.pdf.

Figure ES-1. Recommended Metrics	
ALR 1-3	**Planning Reserve Margin**
ALR 1-4	**BPS Transmission Related Events Resulting in Loss of Load**
ALR 2-4	**Average Percent Non-Recovery of Disturbance Control Standard (DCS) Events**
ALR 2-5	**Disturbance Control Events Greater than Most of Severe Single Contingency (MSSC)**
ALR 3-5	**Operating Limit Excursion (OL Excursion)**
ALR 4-1	**Percent of Automatic Transmission Outages caused by Failed Protection System Equipment**
ALR 6-1	**Transmission Constraint Mitigation**
ALR 6-2	**Energy Emergency Alert 3 (EEA3)**
ALR 6-3	**Energy Emergency Alert 2 (EEA2)**

While the initial charge to the RMWG has been to address metrics in the context of the six ALR characteristics, feedback from NERC Stakeholder groups have suggested broadening this scope of activity. This second slate of recommended metrics built in large part upon preexisting concepts and in most cases pre-existing data, require improvements. If requested to go forward, the RMWG will expand and improve them. However until the Planning and Operating Committees broaden the RMWG scope, the RMWG will focus on metrics within the ALR structure.

Chapter 1—Introduction

1.1 Reliability Metrics Working Group

The NERC Planning Committee (PC), at its December 2007 meeting:

> *"Endorsed the establishment of a new PC Working Group, made of industry experts in operations and planning, including PC and Operating Committee (OC) members, to provide input to the NERC Reliability Metrics and Benchmarking program and make recommendations to the PC of reliability metrics, data collection guidelines and an implementation plan."*

The Reliability Metrics Working Group (RMWG) was established to assist NERC in developing meaningful and objective measures to address the question — "Is North America's electric grid becoming more or less reliable?" While maintaining bulk power system reliability has always been at the heart of its mission, NERC has only just begun to develop a set of industry-recognized metrics is needed to measure industry progress.

Specifically, NERC's *Rules of Procedure*, Section 809 requires NERC to:

> *"Identify and track key reliability indicators as a means of benchmarking reliability performance and measuring reliability improvements. This program will include* ***assessing available metrics, developing guidelines for acceptable metrics, maintaining a performance metrics "dashboard"*** *on the NERC Web site, and developing appropriate reliability performance benchmarks."*

Properly designed metrics will aid NERC's assessment of whether existing Standards are driving the desired behaviors and results. When implemented, these metrics will prompt the industry to decide to enhance or develop new Standards, or confirm existing Standards are achieving the desired results. Metrics will:

- Focus industry on a common set of key reliability metrics and indicators.
- Assist entities identify areas requiring either planning or operational improvement.
- Recognize performance trends and encourage industry's action through root-cause identification.

This report identifies a subset of ALR metrics for data collection and assessment. Further, details of the processes used by the RMWG to define and develop a set of reliability metrics require data collection and reporting mechanisms. The metric development process is comprehensive, providing a foundation for future metric development while encouraging industry-wide input and ensuring stakeholder agreement.

Recommendations from the RMWG include: 1) nine reliability metrics supporting the ALR framework, 2) the metric implementation process supporting future PC-approved metrics, and 3) a three-year work plan outlining further metric development.

Purpose and Deliverables

To carry out its objectives, pursuant to the scope established by the NERC Operating and Planning Committees, the RMWG used the following approach for each of its deliverables:

1. NERC's *Definitions of "Adequate Level of Reliability"*[4] describes the fundamental concepts and six characteristics needed to achieve an adequate level of reliability. The RMWG examined each characteristic to determine the most suitable measures.
2. Each metric was defined describing its purpose and intent, how it relates to reliability, what raw data is needed, how and from whom it should be collected, and what calculations are needed to derive the metric.
3. Processes for collecting the raw data were developed, where possible using existing data gathering mechanisms. Reporting mechanisms were developed to define required timelines, and metric results distribution.
4. Finally, a work plan was developed to describe which metrics would be implemented in the near-term and how new metrics should be developed and implemented to support continuous improvement.

1.2 Consultation with Stakeholders

All NERC functional entities have a role in supporting reliable performance of the BPS. Therefore, the RMWG broadly engaged many of the subgroups of the Operating and Planning Committees to solicit their ideas and contributions. Table 1 outlines the collaborative effort and reach of RMWG through the NERC stakeholder body.

To help ensure all metric suggestions are considered, the Chairs of the Planning and Operating Committees sent a letter on April 6, 2009[5] to subgroup chairs, requesting contributions along with a template providing the necessary detail. The RMWG will review each proposed metric[6] and provide feedback to the contributors describing the specifications of their proposed metric. The RMWG encourages all subgroups to submit new reliability metric proposals while NERC subgroups are expected to provide subject-matter expertise during the metric development and implementation processes.

1.3 Confidentiality

The reliability metric reporting process is designed to respect the confidentiality of data received from individual registered entities. Data submitted by a reporting entity classified as confidential, shall be managed in accordance with NERC's treatment of confidential information, as described in Section 1500 of the *Rules of Procedure.*[7] Neither the entity, nor data directly attributable to a specific entity will be published. As the intent of all these metrics is to provide an overall assessment of reliability, the metrics data will be published at the North American, Interconnection, or Regional levels only. Reporting entity data will not be revealed.

[4] Detailed definitions of ALR are available at http://www.nerc.com/docs/pc/Definition-of-ALR-approved-at-Dec-07-OC-PC-mtgs.pdf.
[5] http://www.nerc.com/docs/pc/rmwg/RMWG_Letter_Metrics_Development.pdf
[6] http://www.nerc.com/filez/rmwg.html
[7] http://www.nerc.com/files/NERC_Rules_of_Procedure_EFFECTIVE_20081219.pdf

Table 1: RMWG Coordination and Outreach Efforts	
Committee	Subgroup
Operating Committee	Operating Reliability Subcommittee
	Resource Subcommittee
	Reliability Coordinator Working Group
	Reliability Fundamental Working Group
Planning Committee	Reliability Assessment Subcommittee
	Resource Issues Subcommittee
	Transmission Issues Subcommittee
	System Protection and Control Subcommittee
	Transmission Availability Data System Task Force
	Data Coordination Subcommittee
	Demand Response Data Task Force
	Integration of Variable Generation Task Force
	G&T Reliability Planning Models Task Force
Standards Committee	
Transmission Owners and Operators Forum	
Canadian Electricity Association	

1.4 NERC's Authority to Obtain Metrics Data

RMWG was charged by the Planning Committee of NERC to provide input to and support the objectives of the NERC Reliability Metrics and Benchmarking program, including the development and improvement of key reliability metrics for the industry. NERC will seek to obtain data through voluntary requests of registered entities prior to exercising any authority to mandate data submittals.

The Working Group functions under direction of the NERC *Rules of Procedure*; specifically:

NERC Rule of Procedure 302 — Essential Attributes for Technically Excellent Reliability Standards which specifies:

> *Standards shall have measureable requirements:*
>
> ***Measurability** — Each performance requirement shall be stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that requirement.*
>
> *Each performance requirement shall have one or more associated measures used to objectively evaluate compliance with the requirement. If performance can be practically measured quantitatively,* ***metrics*** *shall be provided to determine satisfactory performance.*

NERC Rule of Procedure 809 — Scope of the Reliability Performance and Analysis Program which specifies:

> *NERC shall identify and track key reliability indicators as a means of benchmarking reliability performance and measuring reliability improvements. This program will include assessing available* ***metrics****, developing guidelines for acceptable* ***metrics****, maintaining a performance* ***metrics*** *"dashboard" on the NERC Web site, and developing appropriate reliability performance benchmarks.*

Based on the scope approved by the NERC Planning Committee (PC), the specific activities of the RMWG include, but are not limited to:

1. Development of general metrics for the characteristics of an Adequate Level of Reliability (ALR);
2. Definition of reliability measures, including formulae or methods for their calculation;
3. Identification of data collection and reporting guidelines;
4. Recommend a metrics implementation plan.

Each element of the RMWG activities relates to one or more of the tasks implied by the above authorities.

In order to carry out the purpose of this program, data gathering is an essential function. NERC's *Rules of Procedure* provide for the collection of data to carry out the purposes of the Electric Reliability Organization (ERO). The sources of authority for data collection include:

NERC Rule of Procedure 804 — Reliability Assessment Data and Information Requirements, which specifies**:**

> *NERC has the authority to carry out the reviews and assessments of the overall reliability of the interconnected bulk power systems,* ***the regional entities and other entities[8] shall provide sufficient data*** *and other information requested by NERC in support of the annual long-term and seasonal assessments and any special reliability assessments.*

NERC will use voluntary requests for data prior to exercising its authority to mandate data submittals. The NERC's authority granted to issue a mandatory data request[9] in the U.S. is contained in FERC's rules. Volume 18 C.F.R. Section 39.2(d) states:

> *"Each user, owner or operator of the Bulk-Power System within the United States (other than Alaska and Hawaii) shall provide the Commission, the Electric Reliability Organization and the applicable Regional Entity such information as is necessary to implement section 215 of the Federal Power Act as determined by the Commission and set out in the Rules of Procedure of the Electric Reliability Organization and each applicable Regional Entity."*

A data request of U.S. entities can be made based upon NERC's authority in this FERC rule. NERC has filed a *Section 1600: Request for Information or Data[10]* approved by FERC to be included in its *Rules of Procedure*.

1.5 Uses and Limitations of Data and Metrics

The reliability metrics developed by the RMWG are intended to provide high-level directional indications regarding bulk power system reliability and system performance, published on an annual basis. They provide strong and enduring indicators for assessing reliability over the longer-term. As such, these metrics will not and cannot be used to provide situational awareness assessments related to real-time operation. In that sense, these metrics are not a "dashboard" for operational decision-making. The quality of these metrics will improve over time as the industry becomes familiar with the intent of the metrics and provides quality data in a timely manner.

These metrics do not identify "benchmarks" or "targets" for industry. With experience, however, it may be possible to establish benchmarks based on these metrics. Therefore, the RMWG recommends not using the term "Dashboard," rather, "Reliability Indicators," which is suitable and descriptive of their character.

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[8] "Other entities" would include Registered Entities under the ERO structure.

[9] Mandatory data requests are not Reliability Standards; therefore, NERC does not issue fines for non-compliance. However, a non-compliant U.S. Reporting Party may be sanctioned by FERC, since failure to provide required data is a violation of their rules.

[10] This rule allows for a 45-day open comment period for data requests, which then must be approved by the Board of Trustees.

Similarly, the metrics are not intended to be used as part of NERC's Compliance Assessment program. In respect, these metrics are agnostic to industry standards, and are designed to provide a relative and representative view of system reliability and system performance. As a result, some of these metrics may be closely linked to NERC Standards, while others are not.

1.6 BPS Reliability Metrics and Distribution Reliability Metrics

As transmission system owners, operators and regulators grapple with measuring reliability, many proponents of distribution reliability suggest a method similar to that employed by IEEE Standard 1366-2003, *IEEE Guide for Electric Power Distribution Reliability Indices* should be considered. While this approach may be taken, there are substantial differences that need to be recognized. For distribution reliability, the tangible measurement point is the number of customer interruptions and the duration of customer interruptions. In the IEEE Standard, these are measured using System Average Outage Frequency of Interruption (SAIFI) and System Average Outage Duration of Interruption (SAIDI), both of which can be used to evaluate changes and trends in distribution system-level reliability. These two basic measures, however, are not sufficient to evaluate transmission reliability. Additionally, within distribution reliability, in order to establish meaningful trends in performance, the development of methods for determining a "major event day" is necessary. Without this differentiation, addition of day-to-day and major event day performance would result in improper application of statistical techniques. As transmission reliability indices continue to be developed, a need may arise for similar differentiation techniques to be established for the corresponding metrics.

In contrast, transmission systems are generally more redundant, and as such, events important in evaluating reliability trends may not result in loss of service to either local distribution systems or end-use customers. Further, in an event of a significant BPS occurrence, the resulting impact can be widespread. Therefore, measuring BPS reliability has a different character than distribution systems.

Chapter 2—Metric Development Process

This section details the key processes used to develop metrics using both industry contributions as well as performance measures obtained from industry practices. Further, a procedure is developed to encourage industry contributions, vital to the success of this effort.

2.1 Method and Process Chart

In 2009, the RMWG elected to use S.M.A.R.T. (Specific, Measurable, Attainable, Relevant and Tangible), shown in Table 2, as the ranking process providing a consistent approach to identify a high ranking subset of metrics. A consistent scoring system was developed and is used to rank any proposed metrics.

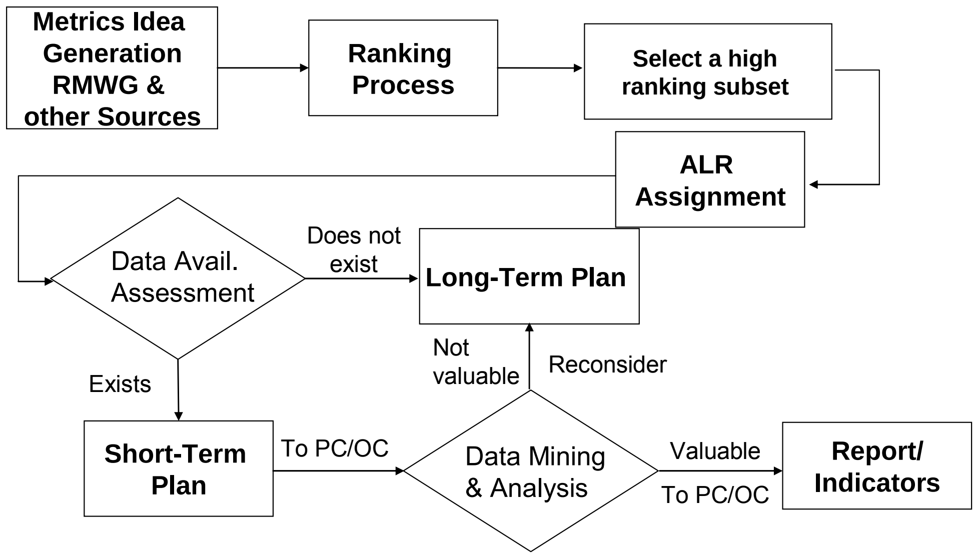
Table 2: SMART Method and Rating*

Rating	S - Specific/Simple	M - Measurable	A - Attainable	R - Relevant	T - Tangible/Timely
	- Be easily understood and not driven by commercial factors (i.e. tariff) - Identify factors that positively or negatively impact reliability - Address reliability problems and solutions	- Be easily measured with regularly collected information - Measure past and current reliability - Measure progress in ensuring reliability - Measure effectiveness of reliability standards and enforcement programs	- The industry can provide the right resources (i.e. funding, time and ability) to improve reliability - Reliability will be measurably improved	- Linked to reliability goals - Provide meaningful information - Provide feedback for improving the Reliability Standards	- Reflect current top priority issues and possess a sense of urgency - Identify reliability gaps and point to existing standards that need to be modified or new standards that need to be developed
3	• Defined in a NERC Standard • Not driven by commercial factors • Addresses specific reliability issues	• Easily measured and reported regularly • Historical data exists at REs and/or NERC and is currently required in NERC Standard • Directly measure effectiveness of standard and enforcement programs	• Compelling business case suggests good chance of being approved through business planning and tariff approval processes • Reliability improvements will be easily seen	• Direct link to reliability goals • Focus on failures and possible solutions or improvements • Provide direct feedback for improving the Reliability Standards	• Directly links to current top priority reliability issues and possess a sense of urgency • Clearly identifies reliability gaps and points to standard improvement needs
2	• Defined within the industry • Not driven by commercial factors • Addresses reliability issues	• Easily measured and reported on occasions • Some historical data exists at REs and/or NERC and is currently required in NERC standard • Measure effectiveness of standard and enforcement programs in a long run	• Additional resources will be required and have a reasonable chance of being approved through business planning and tariff approval processes • Reliability improvements will be apparent within a reasonable period of time (months)	• Some link to reliability goals • Not directly focus on failures and possible solutions or improvements • May provide feedback for improving the Reliability Standards in a long run	• Some link to current top priority reliability issues • May reveal reliability gaps in a long run
1	• Defined somewhere • May have some commercial factors • May relate to reliability issues	• Easily measured and not reported • Some historical data exists at REs and/or NERC • No link to effectiveness of standard and enforcement programs	• Significant resources will be required well beyond normal business planning and tariff approval levels • Reliability improvements will only marginal, or evident over an extended period of time (years)	• No link to reliability goals • Not Focus on failures and possible solutions or improvements • Not tied to a standard improvement	• No link to current top priority reliability issues and does not possess a sense of urgency • Does not identify reliability gaps.

* SMART Score = S rating + M rating + A rating + R rating + T rating

RMWG members divided into sub-teams of experts, brainstormed a large set of potential metrics, and then applied the SMART process (See Figure 1).

Figure 1: Metric Development Process



2.2 Review of Industry Practices

The RMWG reviewed industry practices outlined in a number of reports (see *Reference* Section) to ensure that it took advantage of industry activities throughout the world. In addition, RMWG members shared their own organization's BPS reliability metrics. The metrics used by many organizations address certain aspects of reliability functions associated with the entities. Until now, the industry has lacked an organized way to establish and track the BPS reliability metrics and indices to identify factors that impact reliability and track progress towards sustained reliability improvement.

2.3 2009 Metric Recommendations and Adequate Level of Reliability Linkage

After the metric ranking, RMWG identified a high ranking subset of metrics for further development and assigned each metric a number and a category using the definition of "Adequate Level of Reliability (ALR)":[11]

A Bulk Power System planned and operated with ALR has the following system Characteristics:

ALR.1 Is controlled to stay within acceptable limits during normal conditions;

[11] Detailed definitions of ALR are available at http://www.nerc.com/docs/pc/Definition-of-ALR-approved-at-Dec-07-OC-PC-mtgs.pdf.

The planner must design the System so it can be operated within all limits (voltage, frequency and System Operating Limits), but the operator must operate within limits in real time that are based upon existing conditions.

ALR.2 Performs acceptably after credible Contingencies;

The planners and operators design and operate the System to minimize the risk that credible Contingencies will result in unacceptable performance.

ALR.3 Limits the impact and scope of instability and Cascading Outages when they occur;

System planners design the System so that events such as transmission line and transformer faults, breaker and switch failures, and generator trips, are contained from Cascading and causing the system to lose its integrity.

ALR.4 Facilities are protected from unacceptable damage by operating them within Facility Ratings;

The failure to protect equipment could result in unacceptable reliability for weeks or months due to long lead-time for replacing and repairing equipment.

ALR.5 Integrity can be restored promptly if it is lost;

System operators must have a restoration plan ahead of time, and know from studies and training, on-line tools and experience the operating limits they need to stay within while restoring the system, and how those limits change through the stages of reestablishing system integrity, and up to normal interconnected operations.

ALR.6 Has the ability to supply the aggregate electric power and energy requirements of the electricity consumers at all times;

Taking into account scheduled and reasonably expected unscheduled outages of system components

Table 3 overlays the recommended metrics for use in 2009 along with the associated ALR Characteristic.

Once the preferred subset has been established, the RMWG must determine if data is available to support metric development. If data exist, a pilot assessment can be conducted to confirm the value of the metric and test different methods for displaying the data. If data does not exist, the RMWG must establish a plan to gather such data, taking into consideration the cost and effort involved.

After the available data has been gathered and assessed, the Working Group must evaluate the results to determine the value of the findings. If valuable, the results are presented for consideration as indicators submitted in a report to the NERC Operating and Planning Committees. If the results are deemed not to be valuable, they are returned to the evaluation process for reconsideration.

The entire process should be repeated periodically to review existing metrics and add or discard others as appropriate.

Table 3: 2009 Metrics and ALR Linkage

High Impact
Moderate Impact
Minimal Impact
No Impact

Metrics and ALR Reference Table

Metric	ALR Characteristic					
	1	2	3	4	5	6
	Boundary	Contingencies	Integrity	Protection	Restoration	Adequacy
ALR 1-3						High Impact
ALR 1-4		High Impact				Moderate Impact
ALR 2-4	Moderate Impact	High Impact				Minimal Impact
ALR 2-5		High Impact	Minimal Impact		Minimal Impact	Moderate Impact
ALR 3-5	High Impact	Moderate Impact		Moderate Impact	Minimal Impact	Moderate Impact
ALR 4-1	Moderate Impact	Moderate Impact	Moderate Impact	High Impact		Moderate Impact
ALR 6-1		Moderate Impact	Moderate Impact	Moderate Impact		High Impact
ALR 6-2	High Impact	Moderate Impact		Moderate Impact	Minimal Impact	Moderate Impact
ALR 6-3						High Impact

2.4 Metrics Review Process and Timetable

Bulk Power System reliability assessment metrics are expected to evolve substantially, particularly during the early application of proposals developed by the RMWG. Preliminary metrics are likely calculated from data which has previously been collected. These existing metrics tend to be historic performance measures. The identification of trends from the metrics calculated using existing data, as well as newly developed metrics may allow the industry to discern trends and shift metrics towards becoming leading indicators. As such, metrics will need to be re-evaluated regularly for their relevance and usefulness.

Metrics Solicitation

Regardless of where a metric originated, it is reviewed using the same process for future incorporation into Long-Term Reliability Assessment metric recommendation. Industry stakeholders should be informed via direct notices and postings at appropriate locations of RMWG's interest in evaluating metric suggestions from stakeholders which may be valuable in assessing reliability trends.

Metric Contributions

On an ongoing basis, the RMWG expects to receive contributions from stakeholders about the development, application and trends of various metrics. Thus, a variety of mechanisms to receive proposals has been implemented. As stated previously, an industry request for metrics was issued on April 6, 2009. While there may be a need to remind stakeholders regularly, the intention is to collect contributions on a routine basis, for review and discussion.

Metric Criteria Review

In its initial development, the RMWG used SMART criteria, which is detailed in Section 3.1. These criteria developed a structured method against which each proposed metric, within the various reliability characteristics, could be evaluated. The final ranking created a metric priority list and focused data collection and analysis efforts. The ranking criteria must be re-evaluated and potentially modified periodically to ensure its effectiveness as a ranking tool.

Mechanics of Metric Development

When metric additions are being contemplated, the advocate of the particular metric is asked to promote its value and key attributes as part of the initial evaluation. If the metric is selected for further consideration, additional metric attributes are needed to develop it from raw data to reporting. These attributes include; Metric Number, Brief Description, Criteria Rating and Formula for Calculation, in addition to details as shown on the sample template in Figure 2. Any discarded metric will have the reason for its rejection communicated to its advocate.

Formal Response to Suggested Metrics

A significant emphasis has been placed on the inclusion of input by various stakeholders. As such, it is critical that feedback to suggested metrics be part of the formal process undertaken during the development of metrics. The resolution of any suggested metric will be communicated to its advocate and a database of all suggested metrics will be maintained on the NERC website.

Stakeholder Feedback on Approved Metrics

Industry feedback on approved metrics is welcome and valued. The feedback in the form of comments will be gathered on a similar process to the NERC Standards. The comment form is in an electronic format available on NERC's website. The RMWG will summarize the comments received from the forms and will publish statistics and responses quarterly. A set of specific questions relating to the development of each metrics will be included in the form.

Figure 2: Example Metric Specification Template

ALR6-1 Transmission Constraint Mitigation

Specifications

- **Metric number** — ALR6-1
- **Submittal date** — February 27, 2009
- **Sponsor group (OC, PC or subgroup name** — RMWG
- **Short title** — Transmission Constraint Mitigation
- **Metric Description** — Number of mitigation plans, and increases/decreases in that number, developed to meet reliability requirements in the planning horizon. Mitigation plans are Special Protective Schemes, Remedial Action Schemes, and/or Operating Procedures developed to meet reliability criteria.
- **Purpose** — To gauge the robustness of the transmission system to meet reliability criteria thru installed transmission capacity.
- **SMART Rating** — 14 (S-3, M-3, A-3, R-3, T-2)
- **How will it be suited to indicate performance?** — Trends in the number of mitigation plans required to meet reliability criteria will indicate whether the robustness of the transmission system is increasing, remaining static, or decreasing. A certain number of mitigation plans are economically prudent, however, changes in the number over time will provide an indication of whether additional transmission capacity is being added to meet reliability requirements or further reliance on mitigation plans are reducing the robustness of the grid.
- **Formula** — Number of mitigation plans = sum of individual mitigation plans in EIA reports.
- **Time Horizon** — Planning horizon
- **Metric Start Time or Baseline** — Year 2002 or when data is first available.
- **Data collection Interval and roll up** — Initial data and metrics should be for 200kV and above with later expansion to 100kV and above. Data collection should be on an annual basis consistent with the EIA reporting.
- **Ease of collection** — Collection is by simply counting the number of mitigation plans reported by each TP.
- **Aggregation** — Could be by Interconnection, Regional Entity, or Company. Could be further reported by voltage level.
- **Linkage to NERC Standard** — TPL-001, 002, 003, and 004.
- **Linkage to Data Source** — Assessment required by each TP on an annual basis per TPL-005
- **Need for validation or pilot** — Yes, need to validate consistency of counting and reporting and develop trends for each entity.

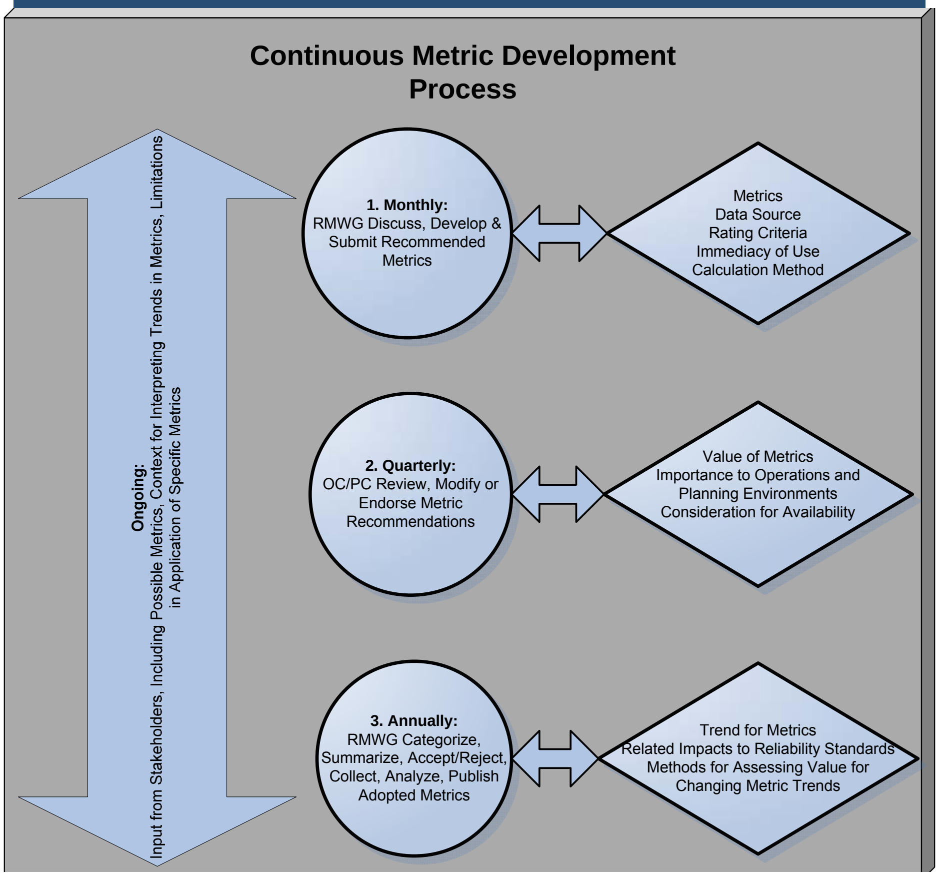
Reporting

- **Can metrics drill down to an individual entity?** — Yes
- **Style (look and feel)** — Line or bar charts
- **Publications and documentation (e.g., section of LTRA)** — report metric trends and analysis results can be included in section of LTRA.
- **Heisenberg effect** — None

Timetable

Figures 3 and 4 shows the key temporal triggers intended to be used to establish the relevance and time significance of any given metric. Ongoing input by stakeholders will be brought into the RMWG environment, and on a regular basis. RMWG will review metric proposals submitted from both stakeholders and members, evaluate gaps in measurement points, target any specific newly available data and make recommendations for the development of a set of metrics for trial use. The metrics will be compared against the evaluation criteria, which are applicable to the proposal. The compilation of this effort will, on a quarterly basis, be reviewed and explored further with the Operating and Planning Committees. Metrics will be refined or removed from consideration based on their feedback. Periodically, agreed-upon metrics will be calculated, analyzed and trends developed in the NERC's Annual Metrics Performance and annual *Long-Term Reliability Assessment* Reports. Ongoing calculation and reporting of newly developed metrics may be appropriate, but will need to be shared with the industry through a periodic report or suitable communications channels.

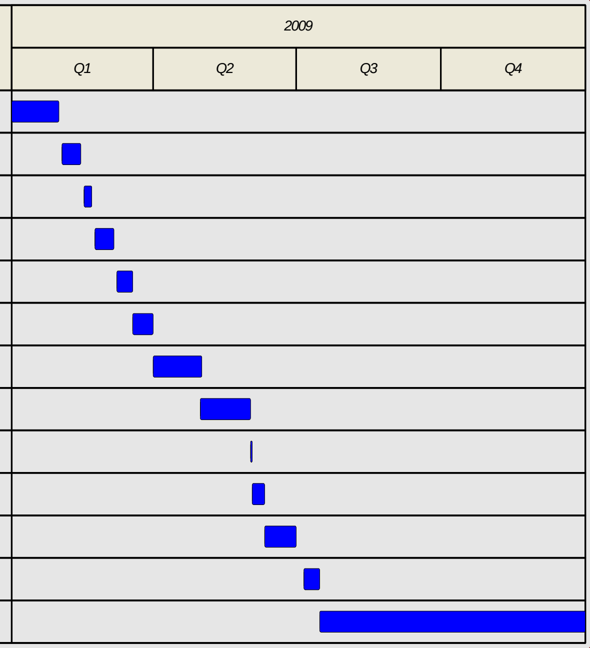
Figure 3: Metric Process Development Time Triggers



Shown in Figure 4, in the Gantt chart below contains generic timeframes, which include key steps in the process for annual review and development of RMWG materials. As can be seen the process is highly collaborative with key stakeholders, yet requires substantial product development from both the RMWG and from NERC staff. The annual timetable is likely to evolve as the process is used and will annually be vetted for its completeness and currency with process changes implemented by the RMWG as needed.

Figure 4: Annual Project Tasks and General Timeframes

ID	Task Name	Duration
1	Review Prior Year's Results and Most-Valued Metrics	4.4w
2	Incorporate Modifications into Current-Year Metrics	2w
3	Review Current-Year Metric Collection Methods	1w
4	Prioritize Metric Value in Blended Metric	2w
5	Review Metrics & Prioritization with Planning & Operating Committees	1.6w
6	Modify Report based on Feedback	1.8w
7	Collect Metrics	4.6w
8	Summarize and Analyze Findings	4.4w
9	Produce Draft Findings	.2w
10	Obtain Feedback on Draft Findings	1.2w
11	Modify Draft Findings	2.8w
12	Conduct In-Person Review of Final Findings	1.6w
13	Collect Future-Year Feedback for Process, Metric & Report Changes	24.2w



Chapter 3—Data Collection, Analysis and Reporting Process

This section outlines the metric data collection, analysis, and reporting processes. Data will be collected from a variety of sources; therefore, one overall collection process may not apply to every different data collection type. Current processes for some data collection will be used in an effort not to duplicate activities. Some metric data will be collected through the current compliance, assessment, TADS, and other existing processes. For example, TADS data and relay misoperation data collected via Compliance activities can be used for the Correct Protection Systems Operations metric. New data collection will be developed specifically to calculate some of the recommended metrics. That said, each metric will most likely have its own data collection process and will need to be documented separately in detail.

3.1 Required Reporting Entities

The required reporting entity will be determined by the type of data collection needed for each metric, and may be different for each metric.

3.2 Metrics Data Entry and Analysis Software

Data entry, for the most part, will be by the Registered Entities to start the data collection processes. Existing data collection procedures will be used where possible.

3.3 Overall Process

Each metric will have its own unique data collection process. When the final list of metrics is approved, the individual metric data collection process will be developed.

3.3.1 Data Request

Data requests will be sent by NERC and Regional Entity staff to the affected entities. Since most data will be collected by existing processes, there may not be many new collection processes developed.

3.3.2 Data Submittal and Review

Details of those processes will be dependent upon the individual metric and data being collected from whom. Data will most likely come from different sources, for example, TADS data, Compliance submittals, etc. Data collection procedures will be determined after the final metrics are chosen. NERC and Regional Entity staffs will review the data quality and may contact Registered Entities directly for correction of any data errors.

3.3.3 Analysis and Reporting

NERC and Regional Entity staff will analyze the data collected and develop suitable presentation of the metrics. Since data will most likely come from different sources for each metric and the collection procedures will be determined after the final metrics are chosen, who (i.e. NERC or Regional Entity staff) analyzes the data and produces the metrics for the reports will be determined for each individual metric.

NERC and Regional Entity staff will develop reports for public release. Some metrics may be reported in existing NERC reports, such as the annual *Long-Term Reliability Assessment*, or seasonal reliability assessment reports. Other metrics may be published in a separate annual Metrics Performance Report. The RMWG or other NERC groups will determine how the approved individual metrics will be reported.

3.4 Metrics Training and Assistance

NERC and Regional Entity staffs may provide training to affected entities for new data collection. This training will be developed after the data collection processes are in place and approved. NERC and Regional Entity staffs may always be called upon for assistance with any data collection process questions.

3.5 Access Policies

Data access policies must protect confidential Compliance and Critical Energy Infrastructure Information (CEII) data, and therefore should follow existing policies that protect it. New policies may be developed, as needed.

Chapter 4—Recommendations

The RMWG has developed a metric development process, data collection procedures, and made recommendations for the first set of metrics. The following recommendations are made:

1. The RMWG should publish an annual Metrics Performance Report of "Reliability Indicators" in the first quarter of each year. This annual report will include the metrics results and an assessment of how the results are related to Reliability Standards. The long-term intent of NERC's reliability metrics program is to evaluate the effectiveness of Reliability Standards, improve them based on the analysis of metrics results and identify any gaps. A discussion of industry feedback on the metrics will be included in this annual report.

2. The RMWG should produce periodic reports to review any additional metrics approved by the PC and OC. In addition, revision to existing metrics or their elimination will also be included in the report. Any changes to the metrics development process, data collection, analysis, and reporting will be included in this periodic report.

3. A comment web tool similar to the process used for NERC Reliability Standards is developed and can be found at the NERC website, to vet these metrics for NERC application. The templates for these metrics are below.

Metrics Recommendations

ALR 1-3 Planning Reserve Margin	
Metric Number	ALR1-3
Submittal Date	February 27, 2009
Sponsor Group (OC, PC or subgroup name)	RMWG
Short Title	Planning Reserve Margin
Metric Description	Percentage of additional capacity over load
Purpose	To gauge the amount of generation capacity available to meet expected demand
How will it be suited to indicate performance?	The percentage provides an indication of the additional capacity available to meet unforeseen increases in demand, unforeseen outages of existing capacity, and trends which will indentify whether capacity additions are keeping up with load growth. Caution should be noted in all reports that this is a capacity based metric and may not provide an accurate assessment of performance in energy limited systems, e.g., hydro capacity with limited water resources.
Formula	Reserve Margin (%) = (Capacity – Load)/Load X 100
Time Horizon	Planning horizon
Metric Start Time or Baseline	Year 2002
Data Collection Interval and Roll Up	Data collection should be on an annual and seasonal basis with reporting for each quarter
Ease of Collection	Data is easily collected and reported on a regional basis now.
Aggregation	Could be on an Interconnection, Regional Entity, or BA level.
Linkage to NERC Standard	
Linkage to Data Source	Data reported now in LTRA and seasonal assessments
Need for Validation or Pilot	No
Data Submitting Entity	Regional Entities

SMART Rating	Total Score	Specific/ Simple	Measurable	Attainable	Relevant	Tangible/ Timely
	13	2	3	3	2	3

Reporting

Style (look and feel)	Line or bar charts
Publications and Documentation (e.g., section of LTRA)	Report metric trends and analysis can be included in both the seasonal and long-term reliability assessments

ALR 1-4 BPS Transmission Related Events Resulting in Loss of Load	
Metric Number	ALR1-4
Submittal Date	February 27, 2009
Sponsor Group (OC, PC or subgroup name)	RMWG
Short Title	Transmission related events resulting in loss of load
Metric Description	Number of transmission related events resulting in loss of load
Purpose	Tracking BPS transmission related credible events which result in loss of load allows planners and operators to validate their design and operating criteria assuring acceptable performance of the system.
How will it be suited to indicate performance?	The relative number (3 or less) provides an indication of good performance or (greater than 3) bad performance measured at a BA, Reliability Organization, Planning Authority, or Interconnection.
Formula	Number of events in a year. "Event" is an unplanned disturbance that produces an abnormal system condition due to equipment failures/system operational actions which result in the loss of firm system demands for more than 15 minutes, as described below (per Standard EOP-004): 1. Entities with a previous year recorded peak demand of more than 3,000 MW are required to report all such losses of firm demands totaling more than 300 MW. 2. All other entities are required to report all such losses of firm demands totaling more than 200 MW or 50 percent of the total customers being supplied immediately prior to the incident, whichever is less. 3. Firm load shedding of 100 MW or more to maintain the continuity of the BPS reliability.
Time Horizon	Historical and current year perspective
Metric Start Time or Baseline	2002, or whenever data first became available
Data Collection Interval and Roll Up	NERC Standard EOP-004 and OE-417 requires reporting of the data
Ease of Collection	Data is available; may require some adjustments to accommodate all the different groups for measurement.
Aggregation	BA, Reliability Organization, Planning Authority, or Interconnection
Linkage to NERC Standard	NERC Standard EOP-004 and OE-417

Linkage to Data Source	NERC data base
Need for Validation or Pilot	Need to validate completeness and consistency of reporting by entities
Data Submitting Entity	Entities responsible for submitting EOP-004 and OE-417 reports

	Total Score	Specific/ Simple	Measurable	Attainable	Relevant	Tangible/ Timely
SMART Rating	15	3	3	3	3	3

Reporting	
Style (look and feel)	Bar Chart or line chart
Publications and Documentation (e.g., section of LTRA)	Seasonal, long-term and monthly performance reports on reliability assessment

ALR 2-4 Average Percent Non-Recovery of Disturbance Control Standard (DCS) Events	
Metric Number	ALR 2-4
Submittal Date	February 27, 2009
Sponsor Group (OC, PC or subgroup name)	RMWG
Short Title	DCS Recoveries
Metric Description	Percentage of the DCS recoveries
Purpose	Measure the Balancing Authority or Reserve Sharing Groups' ability to utilize contingency reserve to balance resources and demand and return the Interconnection frequency within defined limits following a Reportable Disturbance
How will it be suited to indicate performance?	The relative percentage (100%) provides an indication of good performance or (99% or less) bad performance measured at a BA or a reserve sharing group (RSG).
Formula	Percentage of the DCS recoveries=DCS recoveries divided by the number of DCS reportable events, on a monthly basis
Time Horizon	Historical and current year perspective
Metric Start Time or Baseline	2002, or whenever data first became available
Data Collection Interval and Roll Up	NERC Standard BAL-002 requires that a BA or RSG report all DCS events and non-recoveries to NERC
Ease of Collection	Data is available; NERC Resources Subcommittee has the data.
Aggregation	Balancing Authority, and Reserve Sharing Groups
Linkage to NERC Standard	NERC Standard BAL-002
Linkage to Data Source	NERC data base
Need for Validation or Pilot	Need to validate completeness and consistency of reporting by entities
Data Submitting Entity	Balancing Authority and Reserve Sharing Groups

SMART Rating	Total Score	Specific/ Simple	Measurable	Attainable	Relevant	Tangible/ Timely
	15	3	3	3	3	3

Reporting	
Style (look and feel):	Bar Chart or line chart
Publications and Documentation (e.g., section of LTRA)	Monthly or quarterly performance reports

ALR 2-5 Disturbance Control Events Greater than Most Severe Single Contingency (MSSC)	
Metric Number	ALR 2-5
Submittal Date	February 27, 2009
Sponsor Group (OC, PC or subgroup name)	RMWG
Short Title	DCS events greater than MSSC
Metric Description	Number of events greater than MSSC
Purpose	Report the Balancing Authority or Reserve Sharing Groups' Reportable Disturbances great than MSSC in order to measure how much risk the system is exposed to for extreme/unusual contingencies. The results will help validate current contingency reserve requirements and document how often these contingencies occur.
How will it be suited to indicate performance?	The relative number (5 or less) provides an indication of magnitude of acceptable risk or (6 or greater) un-acceptable at a BA, a reserve sharing group (RSG), or interconnection.
Formula	Number of events per year
Time Horizon	Historical and current year perspective
Metric Start Time or Baseline	2002, or whenever data first became available
Data Collection Interval and Roll Up	NERC Standard BAL-002 requires that a BA or RSG report alls DCS events and non-recoveries to NERC, including event greater than MSSC
Ease of Collection	Data is available; NERC Resources Subcommittee has the data. May require some additional information and reporting by the BA and RSG
Aggregation	Balancing Authority, Reserve Sharing Groups, and Interconnection
Linkage to NERC Standard	NERC Standard BAL-002
Linkage to Data Source	NERC data base
Need for Validation or Pilot	Need to validate completeness and consistency of reporting by entities
Data Submitting Entity	Balancing Authority and Reserve Sharing Groups

SMART Rating	Total Score	Specific/ Simple	Measurable	Attainable	Relevant	Tangible/ Timely
	12	3	3	2	2	2

Reporting	
Style (look and feel):	Bar Chart or line chart
Publications and Documentation (e.g., section of LTRA)	Monthly or quarterly performance reports

ALR 3-5 Operating Limit (OL) Excursion	
Metric Number	ALR 3-5
Submittal Date	February 27, 2009
Sponsor Group (OC, PC or subgroup name)	RMWG
Short Title	Operating Limit Excursion
Metric Description	Simple number count of how many times an OL (base case conditions or during a contingency) has been exceeded. To illustrate how quickly OLs are returned to within normal limits, the data will be grouped into 4 time segments as follows: 0 minutes < time OL has been exceeded < 10 minutes 10 minutes ≤ time OL has been exceeded < 20 minutes 20 minutes ≤ time OL has been exceeded < 30 minutes 30 minutes ≤ time OL has been exceeded < ∞ minutes
Purpose	The NERC Glossary of Terms defines an IROL as a System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading Outages that adversely impact the reliability of the Bulk Electric System. This metric will provide the industry with data describing how often these events occur, and their duration.
How will it be suited to indicate performance?	It is anticipated that IROLs would be reported under this measure in the Eastern Interconnection, and SOLs in the WECC and ERCOT Interconnections. This metric is a direct measure of the frequency and duration of flows on an interface exceeding the defined limit. Exceeding OLs could cause widespread outages if prompt operating control actions are not taken in a timely manner to return the system to within normal OL limits. For example, NERC standard IRO-009-1 requires that data for all OLs be collected, and that those greater than acceptable (i.e. greater than 30 minutes) be reported to its Compliance Enforcement Authority.
Formula	Identify all OLs in a Reliability Coordinator area. Count the number of times that an OL has been exceeded. For each OL event, record the start and end date/time that the OL was exceeded so that the elapsed time may be calculated. Retain the times for possible correlation and future study. Identify the number of OLs that are exceeded, and separate these into the 4 time segments listed above.
Time Horizon	Real time operations
Metric Start Time or Baseline and Roll Up	Year 2002, or when data is first available.

Data Collection Interval and Roll Up	Monthly data from historical view					
Ease of Collection	Only Reliability Coordinators need to provide this data. Each Reliability Coordinator currently collects raw OL data regularly as required by IRO-009, but likely do not retain it in the format proposed by this metric. The fourth time segment above is currently reported to Regional Entities as required by TOP-007. The first three time segments above are not currently reported to NERC or the Regional Entities.					
Aggregation	Data should be aggregated at the Regional Entity and Interconnection levels					
Linkage to NERC Standard	TOP-004, TOP-007, IRO-009					
Linkage to Data Source	Reliability Coordinator systems and logs					
Need for Validation or Pilot	Likely not required					
Data Submitting Entity	Reliability Coordinators					
SMART Rating	Total Score	Specific/ Simple	Measurable	Attainable	Relevant	Tangible/ Timely
	14	3	2	3	3	3
Reporting						
Style (look and feel)	Line chart for each of the four time segments above					
Publications and Documentation (e.g., section of LTRA)	Future NERC Reliability Metrics report, published monthly					

ALR 4-1 Percent of Automatic Transmission Outages caused by Failed Protection System Equipment	
Metric Number	ALR 4-1
Submittal Date	February 27, 2009
Sponsor Group (OC, PC or subgroup name)	RMWG
Short Title	Correct Protection System Equipment
Metric Description	Percent of correct protection system operations (i.e. automatic facility trips) that properly cleared faults; compared to all operations (including misoperations) In the interim, this metric will be percent of automatic outages caused by failed protection system equipment, as reported in TADS.
Purpose	The purpose of this metric is to gauge the performance of protection systems (both generator and transmission) on the bulk power system.
How will it be suited to indicate performance?	The relative percentage provides an indication of the relative performance of protection system operations, specifically correct protection system operations as a ratio of total protection system operations. In the future after a few years of data collection, a benchmark percentage could be established (e.g. below 90% is unacceptable). This metric could also be expanded in the future to track human error and equipment failure misoperations (e.g. percent of misoperations caused by human error and equipment failures).
Formula	Percent of Automatic Outages not caused by Failed Protection System Equipment = 100 minus Percent of Automatic Outages caused by Failed Protection System Equipment.
Metric Start Time or Baseline	Year 2008, or when data is first available.
Time Horizon	Historical time frame
Data Collection Interval and Roll Up	To determine if a misoperation has occurred requires that all operations be reviewed by Transmission/Generator Owners. Therefore, the total number of operations should already be known, and could be reported (in total or possibly broken down further by voltage level). Misoperations are currently reported to the Regional Entities for compliance to PRC-003, 004 & 016, but the total number of operations is not. The total number of operations should be available when these three PRC standard revisions become effective as endorsed by the Planning Committee[12]. In the interim since the TADS data provides the total number of automatic transmission system outages and the number of outages caused by failed protection system equipment[13] for 200 kV and above, the initial metric will be defined as follows until the total number of protection system operations can be obtained from the revised PRC-003, 004 and 016 standards that will require a database for tracking. Using the current TADS definitions and data: Percent of Automatic Outages caused by Failed Protection System Equipment is currently calculated and shown

[12] The recommended changes by the Special Protection and Control Subcommittee can be viewed at http://www.nerc.com/docs/pc/Draft_PC_Minutes_June_2009_06-23-09.pdf).
[13] TADS Data Reporting Instruction Manual can be viewed at http://www.nerc.com/docs/pc/tadstf/Ph_I_Data_Reporting_Instr_Manual_112108.pdf.

<table>
<tr><td></td><td colspan="6">in the TADS reports. It should be noted that this current TADS cause code does not contain all reported misoperations.</td></tr>
<tr><td>Ease of Collection</td><td colspan="6">Each Regional Entity collects misoperation data regularly per PRC-003, -004 and -016</td></tr>
<tr><td>Aggregation</td><td colspan="6">Results could be presented by voltage level on a Regional Entity and/or Interconnection basis</td></tr>
<tr><td>Linkage to NERC Standard</td><td colspan="6">PRC-003, -004, and -016</td></tr>
<tr><td>Linkage to Data Source</td><td colspan="6">Initially and temporarily, use the TADS definitions and data. For the long term, use the RE’s misoperation database, as will be revised in the above standards.</td></tr>
<tr><td>Need for Validation or Pilot</td><td colspan="6">Yes, need to validate completeness and consistency of historical data across each region</td></tr>
<tr><td>Data Submitting Entity</td><td colspan="6">Regional Entities</td></tr>
<tr><td rowspan="2">SMART Rating</td><td>Total Score</td><td>Specific/ Simple</td><td>Measurable</td><td>Attainable</td><td>Relevant</td><td>Tangible/ Timely</td></tr>
<tr><td>15</td><td>3</td><td>3</td><td>3</td><td>3</td><td>2</td></tr>
<tr><td colspan="7">Reporting</td></tr>
<tr><td>Style (look and feel):</td><td colspan="6">Line or bar charts</td></tr>
<tr><td>Publications and Documentation (e.g., section of LTRA)</td><td colspan="6">The interim metric is currently shown in TADS reports. The final metric will be included in the annual NERC LTRA report.</td></tr>
</table>

ALR 6-1 Transmission Constraint Mitigation	
Metric Number	ALR 6-1
Submittal Date	February 27, 2009
Sponsor Group (OC, PC or subgroup name)	RMWG
Short Title	Transmission Constraint Mitigation – Planning Horizon
Metric Description	Number of mitigation plans, and increases/decreases in that number, developed to meet reliability requirements in the planning horizon. Mitigation plans are Special Protective Schemes, Remedial Action Schemes, and/or Operating Procedures developed to meet reliability criteria.
Purpose	To gauge the robustness of the transmission system to meet reliability criteria thru installed transmission capacity.
How will it be suited to indicate performance?	Trends in the number of mitigation plans required to meet reliability criteria will indicate whether the robustness of the transmission system is increasing, remaining static, or decreasing. A certain number of mitigation plans may be necessary to support reliable operation, however, changes in the number over time will provide an indication of whether additional transmission capacity is being added to meet reliability requirements or further reliance on mitigation plans are reducing the robustness of the grid.
Formula	Number of mitigation plans = simple numeric sum of individual mitigation plans in regional transmission assessments, i.e., special protection schemes, remedial action schemes, and documented operating procedures specific to transmission constraint mitigation.
Time Horizon	Planning horizon
Metric Start Time or Baseline	Year 2002 or when data is first available.
Data Collection Interval and Roll Up	Initial data and metrics should be for 200kV and above with possible later expansion to 100kV and above. Data collection should be on an annual basis consistent with the TP's assessment under TPL-005.
Ease of Collection	Collection is by simply counting the number of mitigation plans reported by each TP.
Aggregation	Could be by Interconnection, Regional Entity, or Company. Could be further reported by voltage level. Recommended reporting at the Regional Entity level.
Linkage to NERC Standard	TPL-001, 002, 003, and 004.
Linkage to Data Source	Assessment required by each TP on an annual basis per TPL-005

Need for Validation or Pilot	Yes, need to validate consistency of counting and reporting and develop trends for each entity					
Data Submitting Entity	Regional Entities					
SMART Rating	Total Score	Specific/ Simple	Measurable	Attainable	Relevant	Tangible/ Timely
	14	3	3	3	3	2
Reporting						
Style (look and feel):	Line or bar charts					
Publications and Documentation (e.g., section of LTRA)	Report metric trends and analysis results can be included in section of LTRA.					

ALR 6-2 Energy Emergency Alert 3	
Metric Number	ALR 6-2
Submittal Date	February 27, 2009
Sponsor Group (OC, PC or subgroup name)	RMWG
Short Title	Energy Emergency Alert 3 or EEA3
Metric Description	Number of EEA3, alert called on a quarterly basis
Purpose	Measure the number of times EEA3 are issued resulting in firm load interruption due to capacity and energy deficiency
How will it be suited to indicate performance?	The frequency of EEA3s over a period of times provides an indication of performance measured at a BA level or Interconnection level. Quarterly reporting should coincide with seasonal quarters, i.e. Dec-Feb, Mar-May, Jun-Aug, and Sep-Nov. As historical data is gathered, trends in future reports will provide an indication of either decreasing or increasing adequacy in the electric supply system. This metric will also provide some benefit in developing a correlation between EEA events and reserve margins for future planning recommendations. There are no economic factors included in this metric.
Formula	EEA3 results in a count
Time Horizon	Historical and current year perspective
Metric Start Time or Baseline	2002, or whenever data first became available
Data Collection Interval and Roll Up	EEA3 is known as soon as they occur. Data collection should be reported on a quarterly basis. EEA3 is defined in NERC Standard EOP-002-2.
Ease of Collection	EEA3 is currently reported to NERC and data base is maintained. EEA3 is defined in NERC Standard EOP-002-2
Aggregation	Balancing Authority, Regional Entity, and Interconnection
Linkage to NERC Standard	NERC Standard EOP-002-2
Linkage to Data Source	NERC data base
Need for Validation or Pilot	Yes, need to validate consistency of counting and reporting and develop trends for each entity.
Data Submitting Entity	Reliability Coordinators

SMART Rating	Total Score	Specific/ Simple	Measurable	Attainable	Relevant	Tangible/ Timely
	15	3	3	3	3	3

Reporting	
Style (look and feel)	Bar charts
Publications and Documentation (e.g., section of LTRA)	Short-term issue, may be more appropriate in a monthly or quarterly performance report

ALR 6-3 Energy Emergency Alert 2	
Metric Number	ALR 6-3
Submittal Date	February 27, 2009
Sponsor Group (OC, PC or subgroup name)	RMWG
Short Title	Energy Emergency Alert 2 or EEA2
Metric Description	Number of EEA2, alert called on a quarterly basis, excluding activation of DSM or interruption of non-firm load per applicable contracts.
Purpose	To gauge the number of events BAs declare for deficient capacity and/or energy during peak load periods which indicate a shortfall in the adequacy of the electric supply system.
How will it be suited to indicate performance?	The number of events, and any trends in reporting, indicates how robust the system is in being able to supply the aggregate load requirements. Quarterly reporting should coincide with seasonal quarters, i.e. Dec-Feb, Mar-May, Jun-Aug, and Sep-Nov. As historical data is gathered, trends in future reports will provide an indication of either decreasing or increasing adequacy in the electric supply system. This metric will also provide some benefit in developing a correlation between EEA events and reserve margins for future planning recommendations. There are no economic factors included in this metric. EEA events called solely for activation of DSM or interruption of non-firm load per applicable contracts will be excluded from the metric. BAs and RCs will be asked to report what actions are being taken during the EEA-2 event to ensure DSM and non-firm load interruption are excluded from the metric.
Formula	Number of events = sum of each individual EEA2 events called by the BA's
Time Horizon	Historical perspective
Metric Start Time or Baseline	Year 2002
Data Collection Interval and Roll Up	Data collection should be on a seasonal basis and reported for each summer and winter peak period.
Ease of Collection	Data is easily collected by the BAs, RCs, and/or Res
Aggregation	Could be by Interconnection, Regional Entity, or Balancing Authority
Linkage to NERC Standard	EOP-002
Linkage to Data Source	Regional Entity data collection and audits
Need for Validation or Pilot	Data collection currently underway, but existing data reporting will be modified to add additional information on what actions are being taken in EEA-2 events.

Data Submitting Entity	Reliability Coordinators					
SMART Rating	Total Score 15	Specific/ Simple 3	Measurable 3	Attainable 3	Relevant 3	Tangible/ Timely 3
Reporting						
Style (look and feel)	Bar charts					
Publications and Documentation (e.g., section of LTRA)	Short-term issue, may be more appropriate in a monthly or quarterly performance report					

Chapter 5—Metric Trends

This section provides additional information on the available metric data with the intent to provide value in developing correlations between past events and future planning consideration. Data was provided from a variety of sources; therefore, one overall process may not apply to every different data collection type.

Information for ALR 3-5, "Operating Limit Excursion" and ALR 6-1, "Transmission Constraint Mitigation" is not available; therefore, the RMWG will follow the data collection process outlined in section 1.4, "NERC's Authority to Obtain Metric Data".

5.1 ALR 1-3. Planning Reserve Margin

Table 4 Limitations
As the planning reserve margin is a capacity based metric, it does not provide an accurate assessment of performance in energy limited systems, e.g., hydro capacity with limited water resources.

Planning reserve margin is designed to measure the amount of generation capacity available to meet expected demand in planning horizon. Coupled with probabilistic analysis, calculated planning reserve margins have been an industry standard used by planners for decades as a relative indication of adequacy.

Generally, the projected demand is based on a 50/50 forecast.[14] Based on experience, for Bulk Power Systems that are not energy-constrained, reserve margin is the difference between available capacity and peak demand, normalized by peak demand shown as a percentage to maintain reliable operation while meeting unforeseen increases in demand (e.g. extreme weather) and unexpected outages of existing capacity. Further, from a planning perspective, planning reserve margin trends identify whether capacity additions are keeping up with demand growth. As this is a capacity based metric, it does not provide an accurate assessment of performance in energy limited systems, e.g., hydro capacity with limited water resources. Data used here is the same data that is submitted to NERC for seasonal and long-term reliability assessments. Figure 5 and 6 show forecast net capacity reserve margin in US and Canada from 2008 to 2017[15].

[14] These demand forecasts are based on "50/50" or median weather (a 50 percent chance of the weather being warmer and a 50 percent chance of the weather being cooler).

[15] Planning Reserve Margin equals the difference in Net Capacity Resources and Net Internal Demand, divided by Net Internal Demand. Net Capacity Resources is calculated by the sum of Available/Committed/Certain Capacity Resources (depending on the report year) + Net Firm Transactions. Net Internal Demand equals Total Internal Demand less Dispatchable, Controllable Capacity Demand Response used to reduce load (DCLM, IL, CPP w/control, LaaR).

Figure 5

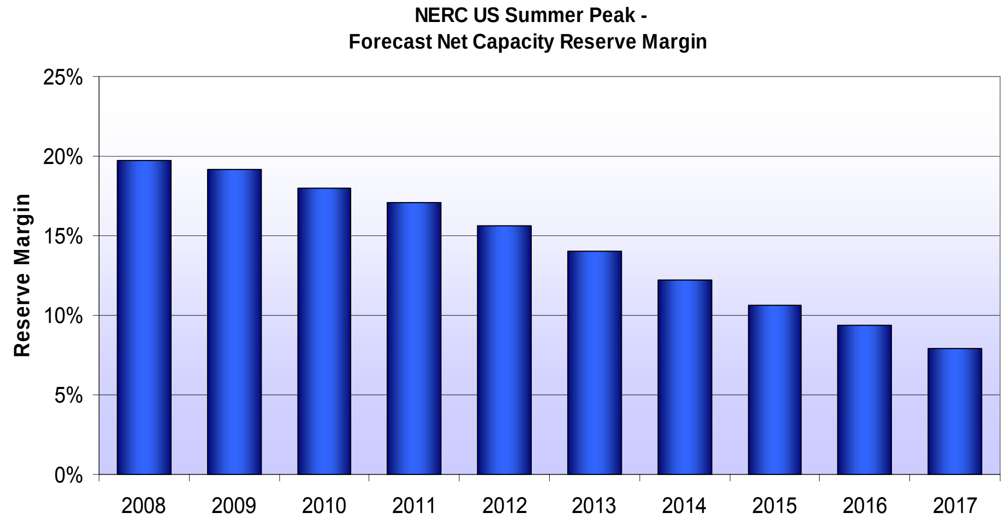
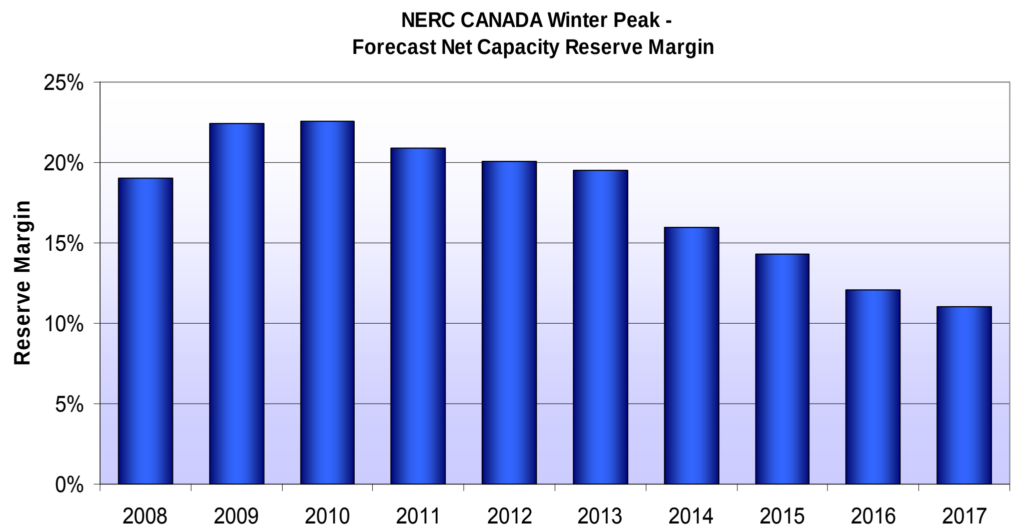


Figure 6



5.2 ALR 1-4. BPS Transmission Related Events Resulting in Loss of Load

This metric is designed to track Bulk Power System (BPS) transmission related credible events which result in loss of load. The metric allows planners and operators to validate their design and operating criteria by identifying the number of instances when there is unacceptable performance of the system.

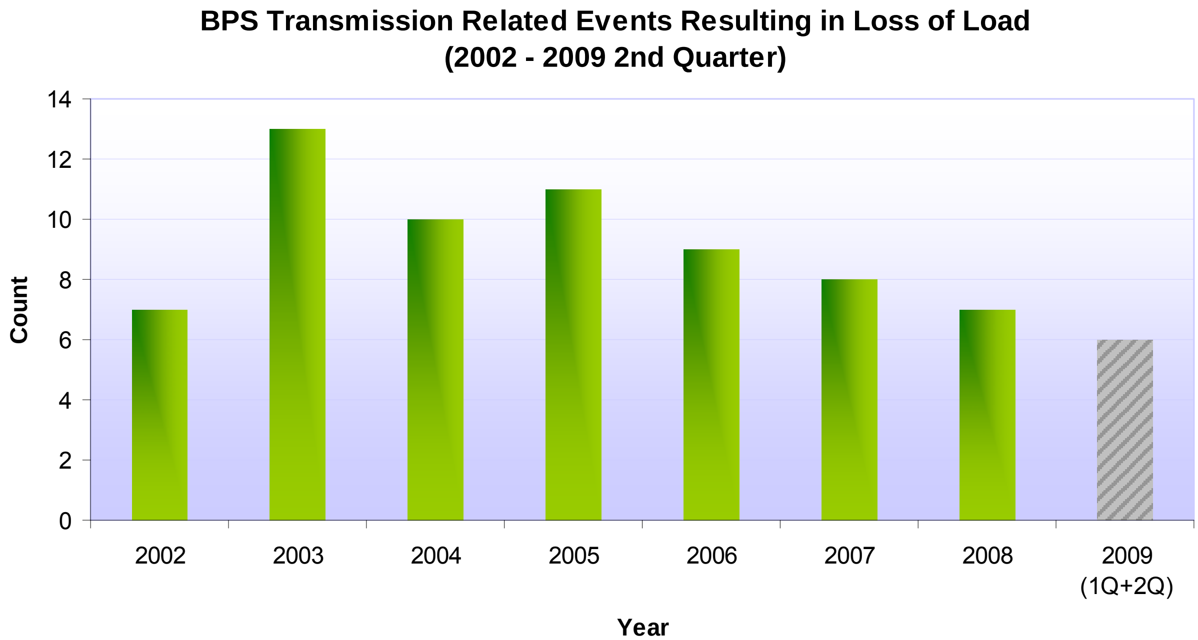
An "Event" is an unplanned disturbance that produces an abnormal system condition due to equipment failures/system operational actions which result in the loss of firm system demands for more than 15 minutes, as described below[16]:

[16] Details of event definitions are available at http://www.nerc.com/files/EOP-004-1.pdf.

1. Entities with a previous year recorded peak demand of more than 3,000 MW are required to report all such losses of firm demands totaling more than 300 MW.
2. All other entities are required to report all such losses of firm demands totaling more than 200 MW or 50 percent of the total customers being supplied immediately prior to the incident, whichever is less.
3. Firm load shedding of 100 MW or more to maintain the continuity of the BPS reliability.

Figure 7 shows the number of BPS transmission related events resulting in loss of firm load.

Figure 7



5.3 ALR 2-4. Average Percent Non-Recovery of Disturbance Control Standard (DCS) Events

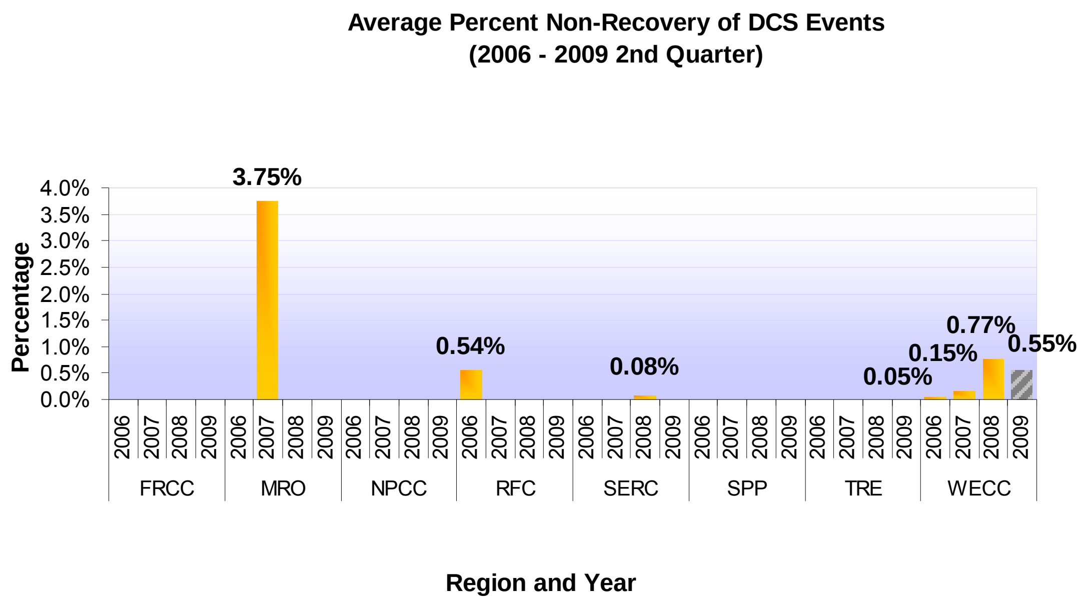
The Disturbance Control Standard Failures metric measures the Balancing Authority or Reserve Sharing Groups' ability to utilize contingency reserve to balance resources and demand and return the Interconnection frequency within defined limits following a Reportable Disturbance.[17]

The relative percentage provides an indication of performance measured at a BA or a reserve sharing group (RSG). NERC Standard BAL-002 requires that a BA or RSG report all DCS events and non-recoveries (failures) to NERC.

Figure 8 shows the average percent non-recovery of DCS events from 2006 to the second quarter of 2009.[18]

[17] Details of the Disturbance Control Performance Standard and Reportable Disturbance are available at http://www.nerc.com/files/BAL-002-0.pdf.

Figure 8



5.4 ALR 2-5. Disturbance Control Events Greater than Most Severe Single Contingency

This metric is designed to identify the number of disturbance events that exceed the Most Severe Single Contingency[19] (MSSC) and is specific to each BA. Balancing Authority or Reserve Sharing Groups report disturbances greater than the MSSC on a quarterly basis. The results will help validate current contingency reserve requirements. Investigations of these events document how often these contingencies occur. The MSSC is determined based on the specific configuration of each system and that while there are general guidelines; they vary in significance and impact on the Bulk Power System.

Figure 9 represents the number of DCS events that are greater than the MSSC.

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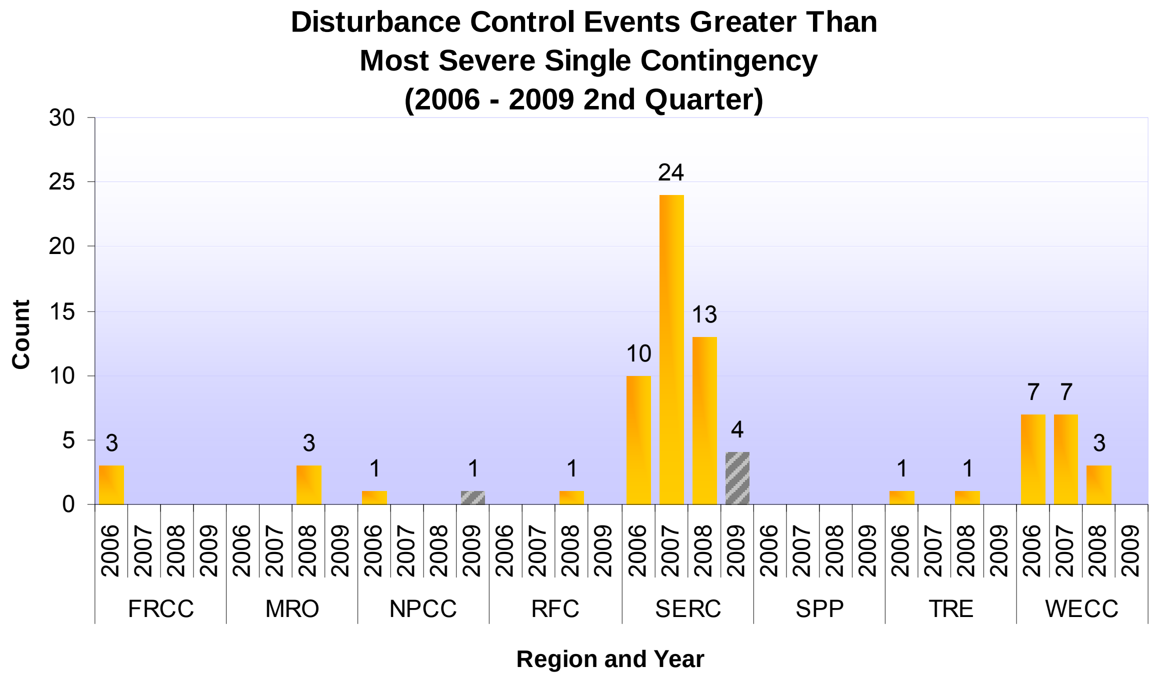
[18] One DCS event within the MRO region did not fully recover to 100 percent within 15 minutes during 2007. The MW amount called on for this contingency reserve was understated and insufficiently low. However, there were sufficient contingency reserves available in the Midwest ISO Contingency Reserve Sharing Group at the time of this event and the reserves were deliverable. The 3.75 percent non-recovery shown for the MRO region for 2007 does not indicate that there was a lack of contingency reserves or an inability to deliver contingency reserves during this event or any other event within the MRO region in 2007.

[19] Details of the most severe single contingency determination process are available at http://www.nerc.com/files/BAL-002-0.pdf. For WECC, Disturbance Control Standards are more stringent, which require reserves over and above MSSC. The details are available from WECC Standard BAL-002-WECC-1: http://www.nerc.com/files/BAL-002-WECC-1.pdf.

Figure 9



5.5 ALR 4-1. Percent of Automatic Transmission Outages caused by Failed Protection System Equipment

The purpose of this metric is to gauge the performance of protection systems (both generator and transmission) on the bulk power system.

The relative percentage provides an indication of the relative performance of protection system operations, specifically correct protection system operations as a ratio of total protection system operations. This metric could also be expanded in the future to track human error and equipment failure misoperations (e.g. percent of misoperations caused by human error and equipment failures).

To determine if a misoperation has occurred requires that all operations be reviewed by Transmission/Generator Owners. Therefore, the total number of operations should already be known, and could be reported (in total or possibly broken down further by voltage level). Misoperations are currently reported to the Regional Entities for compliance to PRC-003, 004, and 016, but the total number of operations is not. The total

Table 5 Limitations

Interim Measure: In the interim since the TADS data provides the total number of automatic transmission system outages and the number of outages caused by failed protection system equipment[20] for 200 kV and above, the current metric is defined as the Percent of Automatic Outages caused by Failed Protection System Equipment. The correct protection system operations will be used once the total number of protection system operations can be obtained from the revised PRC-003, 004 and 016 Standards.

[20] TADS Data Reporting Instruction Manual can be viewed at http://www.nerc.com/docs/pc/tadstf/Ph_I_Data_Reporting_Instr_Manual_112108.pdf.

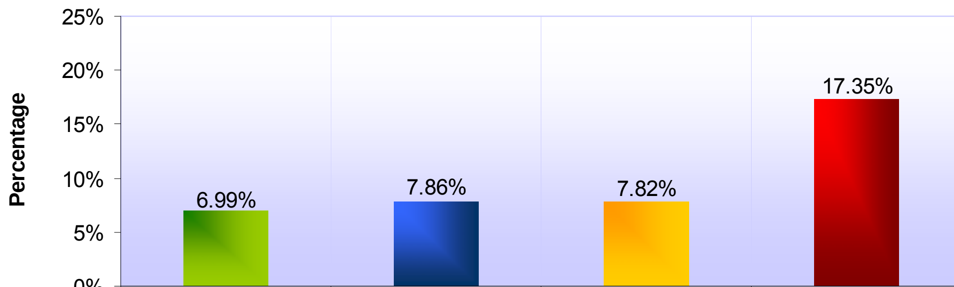
number of operations should be available when these three PRC standard revisions become effective as endorsed by the Planning Committee.[21]

In the interim since the TADS data provides the total number of automatic transmission system outages and the number of outages caused by failed protection system equipment[22] for 200 kV and above, the current metric is defined as the Percent of Automatic Outages caused by Failed Protection System Equipment. The correct protection system operations will be used once the total number of protection system operations can be obtained from the revised PRC-003, 004 and 016 Standards.

Figure 10 shows the percent of automatic outages caused by failed protection system equipment reported in 2008.

Figure 10

2008 Percent of Automatic Outages Caused by Failed Protection Systems



	230 kV	345 kV	500 kV	765 kV
Failed Protection Outages	189	122	50	17
Other Automatic Outages	2515	1430	589	81
Percentage	6.99%	7.86%	7.82%	17.35%

[21] The recommended changes by the Special Protection and Control Subcommittee can be viewed at http://www.nerc.com/docs/pc/Draft_PC_Minutes_June_2009_06-23-09.pdf.
[22] TADS Data Reporting Instruction Manual can be viewed at http://www.nerc.com/docs/pc/tadstf/Ph_I_Data_Reporting_Instr_Manual_112108.pdf.

5.6 ALR 6-2. Energy Emergency Alert 3 (EEA3)

This metric measures the number of times EEA3s are issued. EEA3 events are firm load interruptions due to capacity and energy deficiency. EEA3 is currently reported to NERC and a data base is maintained. EEA3 is defined in NERC Standard EOP-002-2.[24]

The frequency of EEA3s over a period of times provides an indication of performance measured at a BA level or Interconnection level. As historical data is gathered, trends in future reports will provide an indication of either decreasing or increasing adequacy in the electric supply system. This metric will also provide value in developing a correlation between EEA3 events and reserve margins for future planning recommendations. There should be no economic factors included in use of EEA3. However in certain regions and under certain reserve sharing agreements the industry has adapted this metric in a way which requires EEA3 declarations in order to implement certain commercial or tariff processes. In those regions where EEA3 events are implemented under tariff or contract requirements for economic purposes, these have been eliminated from the data record. This was not the intended purpose of the EEA process and unfortunately has the effect of making a reliability indicator into an economic tool for operation of the system.

Figure 11 shows the number of EEA3 events between 2006 and the second quarter of 2009 at regional level.

Table 6 Use of EEA3

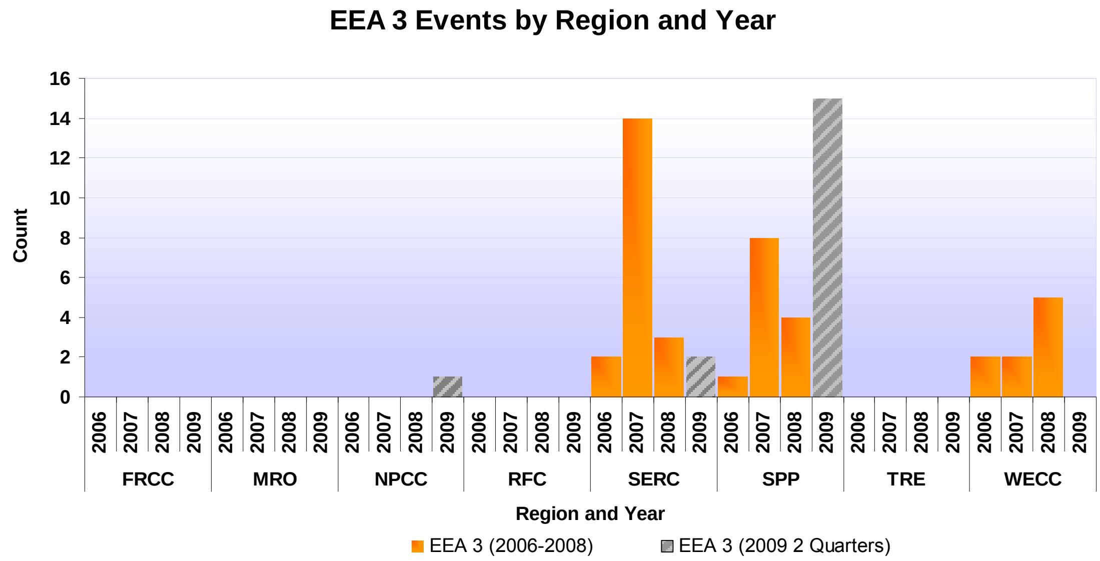
The SPP RC has issued more EEA3s in 2009 than previous years and anticipates that the Acadiana Load Pocket[23] will be a concern for the remainder of the 2009 summer. SPP is working with each entity in the area to resolve the issues and protect the load in the area. As a long-term solution, the SPP ICT facilitated an agreement with members in the Acadiana pocket to expand and upgrade electric transmission in the area. The joint project includes upgrades to certain existing electric facilities as well as the construction of new substations, transmission lines, and capacitor banks, and the total estimated cost is approximately $200 million. Each utility is responsible for various components of the project work. All upgrades are expected to be completed between 2010 and 2012. The detailed expansion and upgrades are available at http://www.spp.org/publications/SPP_Acadiana_news_release_1-19-09.pdf. When completed, these upgrades will address the congestion issues currently experienced in the Acadiana area.

The high numbers of EEA3s for SERC in 2007 were the result of peak system conditions and have not been repeated in recent periods. Summer 2007 was the period when the last regional peak occurred.

[23] Refer to SPP's Regional Assessment in 2009 LTRA for mode details of adequacy issues in the Acadiana Load Pocket.

[24] EEA3 definition is available at http://www.nerc.com/files/BAL-002-0.pdf

Figure 11



5.7 ALR 6-3. Energy Emergency Alert 2 (EEA2)

This metric is to measure the number of events BAs declare for deficient capacity and energy during peak load periods which may serve as a leading indicator of energy and capacity shortfall in the adequacy of the electric supply system. It is a leading indicator in that it provides a sense of the frequency of precursor events to the more severe EEA3 declarations.

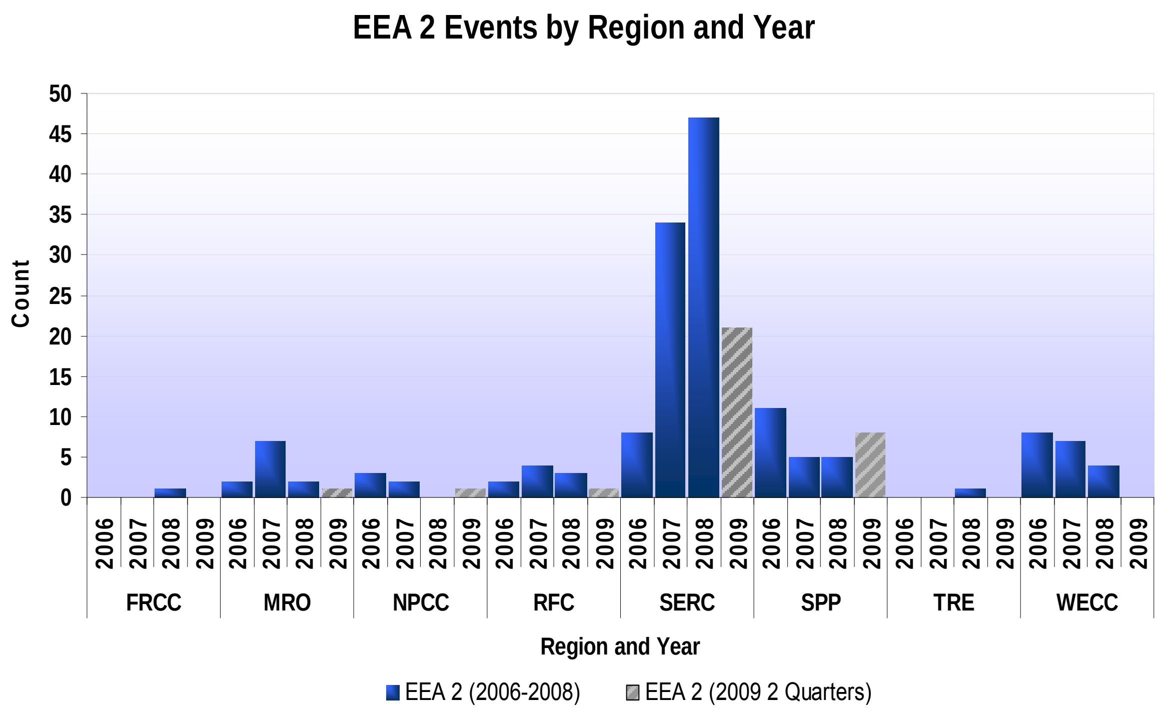
Table 7 Limitations
Future data reporting will be modified to add additional information on what actions are being taken in EEA2 events to ensure DSM and non-firm load interruption are excluded from the metric.

The number of EEA2 events, and any trends in reporting, indicates how robust the system is in being able to supply the aggregate load requirements. The historical record includes DSM activations and non-firm load interruptions per applicable contracts within the EEA2 alerts. These Demand Resources are legitimate resources to be called upon by BAs and are not of direct concern regarding reliability. As data is gathered on a going forward basis, future reports will provide an indication of either decreasing or increasing adequacy in the electric supply system. EEA2 events calling solely for activation of DSM (controllable or contractually prearranged demand side dispatch programs) or interruption of non-firm load per applicable contracts will be excluded from the metric as demand response is a legitimate resource. This metric will also provide value in developing a correlation between EEA2 events and reserve margins for future planning recommendations.

Through the RMWG, the NERC Planning Committee is proposing that data reporting process be modified to add additional information on what actions are being taken in EEA2 events to ensure DSM and non-firm load interruption are excluded from the metric.

Figure 12 shows the number of EEA2 events between 2006 and the second quarter of 2009 unadjusted for DSM activations.

Figure 12



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Appendix I: Letter Announcing the RMWG

January 10, 2008

Reliability Metrics Working Group

Dear Working Group Members:

The NERC Planning Committee (PC) at its 12–13 December 2007 meeting[25] ***"Endorsed the establishment of a new PC working Group, made of industry experts in operations and planning, including PC and Operating Committee (OC) members, to provide input to the NERC Reliability Metrics and Benchmarking program and make recommendations to the PC of reliability metrics, data collection guidelines and an implementation plan."***

I am appointing this new Planning Committee Working Group to help meet the needs of the NERC Reliability Metrics and Benchmarking Program. Some specific assignments include, but are not limited to: 1) Review and comment on the NERC's Reliability Metrics white paper, 2) Establish sets of metrics to be applied in years one – five and years six – ten of the Long Term Reliability Assessment (LTRA), 3) Develop general metrics for the characteristics of an Adequate Level of Reliability (ALR), 4) Define reliability measures, including formulae or methodologies for their calculation, 5) Identify data collection and reporting guidelines, and 6) Recommend a metrics implementation plan. The Planning Committee will review the scope and need for the Working Group every two years.

The Working Group appointments, as identified in Attachment A, are effective immediately. Mr. Jason Shaver will serve as the Working Group Chairman,[[26]] and Ms. Jessica Bian will serve as NERC staff support. The Planning Committee and Operating Committee will also consider additional appointments to the Working Group at its March, 2008 meeting as needed to enhance the Working Group.

The Working Group shall immediately begin its work and is requested to submit a status report, including any preliminary recommendations, to the Planning Committee at each PC meeting. The Working Group shall also report its progress at each joint OC and PC meeting and will also meet with the Operating Committee as requested.

I wish to thank the Working Group members for their willingness to serve and I look forward to hearing your recommendations at our future meetings. If there is anything that you need from the Planning Committee to accomplish your assignment, please do not hesitate to contact me.

Sincerely,

Scott M. Helyer
Chairman,
NERC Planning Committee

CC: Gayle Mayo, OC Chair
NERC Planning Committee

[25] http://www.nerc.com/docs/pc/Final_PC_Dec_2007_Minutes.pdf

[26] On November 6th, 2008, Mr. Herbert Schrayshuen was appointed as chair of the RMWG. In addition, Mr. William O. Adams was appointed as vice chair of the RMWG.

Appendix II: RMWG Scope and Three Year Work Plan

Purpose and Deliverables

The Group will provide input and support the objectives of the NERC Reliability Metrics and Benchmarking[27] program, including the development and improvement of NERC's key reliability metrics. Specific activities will include, but not be limited to:

1. Development of general metrics[28] for the characteristics of an Adequate Level of Reliability (ALR);
2. Definition of reliability measures, including formulae or methodologies for their calculation;
3. Identification of data collection and reporting guidelines; and
4. Recommending a metrics implementation plan.

The Group will report its progress at each joint meeting of the Operating Committee (OC) and Planning Committee (PC).

Membership

- NERC will seek membership from industry experts in operations and planning, including members from OC and PC, in the areas of performance metrics, benchmarking and analysis, with final selection agreed to by the chairs of the OC and PC.
- The NERC Manager of Benchmarking.
- Members must be willing to commit their time to participate in the Group's discussions, including the development of reports.

Governance

The Group reports to the PC. The PC will endorse the recommendations by the Group of reliability metrics, data collection guidelines and the implementation plan. The PC will review the scope and need for the group every two years. The Group Chair is appointed by the PC Chair.

Meetings

Meetings and conference calls as needed.

[27] Defined in Section 809 of the NERC Rules of Procedure, available at http://www.nerc.com/files/NERC_Rules_of_Procedure_EFFECTIVE_20080813.pdf

[28] Metrics covering both operations (real-time) and future reliability.

2009 Tasks				
Mar-09	**Jun-09**	**Jul-09**	**Sep-09**	**Dec-09**
Provide PC/OC a list of ALR metrics and other reliability measures for consideration	Recommend first set of ALR metrics for PC/OC endorsement in July	Obtain PC / OC endorsement of recommendations by the Group	Recommend data collection guidelines and an implementation plan	Present recommended report of metrics definitions for implementation and data collection
			Review and recommend leading indicators and event classification	Begin implementation of data collection assuming endorsement of PC/OC
			Enhance and update metrics definitions on the NERC website	Proposal for development of a centralized benchmarking repository

Tasks			
Mar-2010	**Jun-2010**	**Dec-2010**	**2011**
Publish 2009 annual reliability performance report	Recommend second set of ALR metrics	Monitor ALR metrics and leading indicators	Report on changes in reliability performance compared to established benchmarks
	Review and analyze performance trends periodically and establish benchmarks for each performance indicator	Propose changes and additions as needed	Develop and identify any areas for performance improvement. Identify needs revealed by the metrics program; recommend standard changes if indicated

Appendix III: RMWG Roster

Chair	Herbert Schrayshuen Director Reliability Assessment	SERC Reliability Corporation 2815 Coliseum Centre Drive Charlotte, North Carolina 28217	(704) 940–8223 (315) 439–1390 Cell hschrayshuen@serc1.org
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Appendix IV: Abbreviations Used in This Report

Abbreviations	
ALR	Adequate Level of Reliability
BA	Balancing Authority
BPS	Bulk Power System
CEII	Critical Energy Infrastructure Information
DCS	Disturbance Control Standard
DOE	Department Of Energy
EEA	Energy Emergency Alert
ERCOT	Electric Reliability Council of Texas
ERO	Electric Reliability Organization
ESAI	Energy Security Analysis, Inc.
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
IEEE	Institute of Electrical and Electronics Engineers
IESO	Independent Electricity System Operator
IROL	Interconnection Reliability Operating Limit
LOLE	Lost of Load Expectation
MRO	Midwest Reliability Organization
MSSC	Most Severe Single Contingency
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
OC	Operating Committee
OL	Operating Limit
PC	Planning Committee
RE	Regional Entities
RFC	Reliability First Corporation
RMWG	Reliability Metrics Working Group
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SERC	South Eastern Electric Reliability Council
SMART	Specific, Measurable, Attainable, Relevant and Tangible
SOL	System Operating Limit
SPP	Southwest Power Pool
TADS	Transmission Availability Data System