Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. Standards Committee authorized moving the SAR forward to standard development 10/17/2013.
2. SAR posted for comment 11/06/13-12/05/13.
3. Informal posting for comment 03/28/14-04/28/14.

Description of Current Draft

This is the second draft of the proposed standard and is being posted for formal stakeholder comments and initial ballot. This draft includes the modifications based on the Five-Year Review Team recommendations, comments submitted by stakeholders during the SAR comment period, comments submitted by stakeholders during the informal comment period, as well as other items identified in the SAR and applicable FERC directives from FERC Order 693.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Parallel Initial Ballot	July 2014
Final ballot	October 2014
BOT adoption	November 2014
File standard with regulatory authorities	December 2014

Effective Dates

The standard shall become effective on the first day of the first calendar quarter that is 12 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is12 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Version History

Version	Date	Action	Change Tracking
1	TBD	Initial Standard	Merged EOP-001-2.1b, EOP-002-3.1 and EOP-003-2.

Definitions of Terms Used in Standard

This section includes all newly-defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

The EOP SDT proposed to revise the current approved definition of **Energy Emergency** as follows:

> **Energy Emergency -** A condition when a Load-Serving Entity or Balancing Authority has exhausted all other resource options and can no longer meet its ~~customers'~~ expected ~~energy~~ Load obligations.

The proposed revisions are intended to clarify that an Energy Emergency is not necessarily limited to a Load-Serving Entity. This term, or variations of it, is also used in other standards, as indicated below. The EOP SDT is obligated to review other standards in which this term is used to determine if reliability gaps or redundancies are created by the proposed revision to the defined term. The EOP SDT has made a review of other standards in which the term "energy emergency" is used and does not believe the proposed revisions change the reliability intent of requirements or definitions.

- **BAL-002-WECC – Contingency Reserve**: This standard becomes enforceable on October 1st, 2014. The EOP SDT does not believe that the proposed definition revision will create any redundancies or gaps in reliability.
- **IRO-005-3.1a — Reliability Coordination — Current Day Operations** - This standard was revised under Project 2006-06 and the reference to Energy Emergency was removed from the standard. The standard was approved by the NERC BOT and filed with FERC. NERC has requested that FERC defer action on its petition and is revising this standard under project 2014-03, TOP/IRO revisions. This project is scheduled to be completed no later than January 31, 2015. The two standard drafting teams are coordinating the definition revision to ensure there are no redundancies.
- **MOD-004-1 — Capacity Benefit Margin:** This standard is being retired and replaced with MOD-001-2 — Modeling, Data, and Analysis — Available Transmission System Capability (NERC BOT approved February 6, 2014). The term "energy emergency" is not used in the new standard. The EOP SDT does not believe that the proposed definition revision will create any redundancies or gaps in reliability to the existing approved standard.
- **INT-004-3 – Dynamic Transfers:** This standard was a revision to INT-004-2 under Project 2008-12. INT-004-3 was approved by the NERC BOT and filed with FERC. The EOP SDT does not believe that the proposed definition revision will create any redundancies or gaps in reliability.
- **Defined term Emergency Request for Interchange:** This term is not used in any existing approved standard.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Emergency Operations**
2. **Number:** **EOP-011-1**
3. **Purpose:** To mitigate the effects of operating Emergencies by ensuring each Transmission Operator and Balancing Authority has developed Emergency Operating Plans, and that those plans are coordinated within a Reliability Coordinator Area.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authority

   4.1.2 Reliability Coordinator

   4.1.3 Transmission Operator

5. **Background:**

EOP-011-1 consolidates requirements from three standards: EOP-001-2.1b, EOP-002-3.1, and EOP-003-2.

The Project 2009-03 Emergency Operations Standard Drafting Team (EOP SDT) developed EOP-011-1 by considering the following inputs:

- Applicable FERC directives;
- Five Year Review Team (FYRT) recommendations;
- Independent Expert Review Panel recommendations; and
- Paragraph 81 criteria.

The standard streamlines the requirements for Emergency operations for the Bulk Electric System (BES) into a clear and concise standard that is organized by Functional Entity. In addition, the revisions clarify the critical requirements for Emergency Operations, while ensuring strong communication and coordination across the Functional Entities.

B. Requirements and Measures

R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System. At a minimum, the Emergency Operating Plan shall include the following elements: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning]*

1.1. Roles and responsibilities to activate the Emergency Operating Plan;

1.2. Strategies to prepare for and mitigate Emergencies including, at a minimum:

1.2.1. Notification to the Reliability Coordinator, to include current and projected System conditions, when experiencing an operating Emergency;

1.2.2. Voltage control;

1.2.3. Cancellation or recall of Transmission and generation outages;

1.2.4. System reconfiguration;

1.2.5. Redispatch of generation request;

1.2.6. Operator-controlled manual Load shedding plan coordinated to minimize the use of automatic Load shedding;

1.2.7. Mitigation of reliability impacts of extreme weather conditions; and

1.3. Strategies for coordinating Emergency Operating Plans with impacted Transmission Operators and impacted Balancing Authorities.

Rationale for Requirement R1: The EOP SDT examined the recommendation of the EOP FYRT and FERC directive to provide guidance on applicable entity responsibility that was included in EOP-001-2.1b. The EOP SDT removed EOP-001-2.1b, Attachment 1, and incorporated it into this standard under the applicable requirements. This also establishes a separate requirement for the Transmission Operator to create an Emergency Operating Plan.

Requirement R1 Part 1.2. was added to this standard for the Transmission Operator to address strategies to prepare for and mitigate Emergencies using voltage control methods, which could include switching of capacitor and reactor banks, generator reactive output, and the use of synchronous condensers.

It is the EOP SDT's intent for Requirement R1 Part 1.2.6. that what is unwanted is the use manual Load shedding which is already armed for automatic Load shedding. The automatic Load shedding schemes are the important backstops against cascading outages or system collapse. If an entity manually sheds a Load which was included in an automatic scheme, it reduces the effectiveness of that automatic scheme. The EOP SDT acknowledges that, in the formulation of manual Load shedding plans, complete exclusion of Loads armed for automatic Load shedding may not be possible. Each entity should, however, evaluate their automatic Load shedding schemes and coordinate their manual plans so that overlapping use of Loads is avoided to the extent reasonably possible.

"Emergency Operating Plan" within the requirements of EOP-011-1 is not intended as a newly-defined term. It is the intent of the EOP SDT that two defined terms are being used: the defined term "Emergency" and the defined term "Operating Plan."

M1. Each Transmission Operator will have a dated and approved Emergency Operating Plan developed in accordance with Requirement R1 that has been approved by its Reliability Coordinator, as shown with the documented approval from its Reliability Coordinator; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its plan was implemented in accordance with Requirement R1.

R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate Capacity and Energy Emergencies. At a minimum, the Emergency Operating Plan shall include the following elements: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning]*

2.1. Roles and responsibilities to activate the Emergency Operating Plan;

2.2. Notification to the Reliability Coordinator, to include current and projected System conditions, when experiencing a Capacity Emergency or Energy Emergency;

2.3. Criteria to declare an Energy Emergency Alert, per Attachment 1;

2.4. Strategies to prepare for and mitigate Emergencies including, at a minimum:

2.4.1. Generating resources in its Balancing Authority Area:

2.4.1.1. capability and availability;

2.4.1.2. fuel supply and inventory concerns;

2.4.1.3. fuel switching capabilities; and

2.4.1.4. environmental constraints.

2.4.2. Voluntary Load reductions;

2.4.3. Public appeals;

2.4.4. Requests to government agencies to implement their programs to achieve necessary energy reductions;

2.4.5. Reduction of internal utility energy use;

2.4.6. Customer fuel switching;

2.4.7. Use of Interruptible Load, curtailable Load and demand response;

2.4.8. Operator-controlled manual Load shedding plan coordinated to minimize the use of automatic Load shedding; and

2.4.9. Mitigation of reliability impacts of extreme weather conditions.

2.5. Strategies for coordinating Emergency Operating Plans with impacted Balancing Authorities and impacted Transmission Operators.

Rationale for Requirement R2: To address the recommendation of the FYRT and the FERC directive to provide guidance on applicable entity responsibility in EOP-001-2.1b, Attachment 1, the EOP SDT removed EOP-001-2.1b, Attachment 1, and incorporated it into this standard under the applicable requirements. EOP-011-1 also establishes a separate requirement for the Balancing Authority to create its Emergency Operating Plan to address Capacity and Energy Emergencies.

If any Parts of Requirement R2 are not applicable, the Balancing Authority should note "not applicable" in their plan.

The EOP SDT retained the statement "Operator-controlled manual Load shedding," as it was in the current EOP-003-2 and is consistent with the intent of the EOP SDT.

With respect to automatic Load shedding schemes that include both UVLS and UFLS, the EOP SDT's intent is to keep manual and automatic Load shedding schemes as separate as possible, but realizes that sometimes, due to system design, there will be overlap. The intent in Requirement R2 Part 2.4.8. is to minimize as much as possible the use manual Load shedding which is already armed for automatic load shedding. The automatic Load shedding schemes are the important backstops against cascading outages or system collapse. If an entity manually sheds a Load which was included in an automatic scheme, it reduces the effectiveness of that automatic scheme. Each entity should evaluate their automatic Load shedding schemes and coordinate their manual plans so that any overlapping use of Loads is avoided to the extent reasonably possible.

Requirement R2 Part 2.4.8 references "coordination" – the intention is that manual and automatic systems be coordinated with each other to minimize overlap of the Loads planned to be shed in each. The reference is not intended to require coordination with other entities.

The EOP SDT retained Requirement R8 from EOP-002-3.1 and added it to the Parts in Requirement R2.

M2. Each Balancing Authority will have a dated and approved Emergency Operating Plan developed in accordance with Requirement R2 that has been approved by its Reliability Coordinator, as shown with the documented approval from its Reliability Coordinator; and will have as evidence, such as operator logs or other operating documentation, voice recordings, or other communication documentation to show that its plan was implemented in accordance with Requirement R2.

R3. Each Reliability Coordinator shall approve or disapprove, with stated reasons for disapproval, Emergency Operating Plans submitted by Transmission Operators and Balancing Authorities within 30 calendar days of submittal. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

Rationale for R3: Since Requirements R1 and R2 both require a submittal for approval, Requirement R3 requires approval or disproval. This aligns with similar requirements in EOP-006-2, Requirement 5.1.

M3. The Reliability Coordinator will have documentation, such as e-mails with receipts or registered mail receipts, that it approved or disapproved, with stated reasons for disapproval, the Transmission Operator and Balancing Authority submitted and revised

Emergency Operating Plans within 30 calendar days of submittal in accordance with Requirement R3.

R4. Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority shall notify, as soon as practical, other impacted Reliability Coordinators, Balancing Authorities and Transmission Operators. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

Rationale for R4: The EOP SDT added the words "as soon as practical" to the requirement to communicate the intent that timeliness is important, while balancing the concern that in an Emergency there may be a need to alleviate excessive notifications on Balancing Authorities and Transmission Operators. This was an existing requirement in EOP-002-3.1 for Balancing Authorities.

M4. Each Reliability Coordinator that receives an Emergency notification from a Balancing Authority or Transmission Operator will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that will be used to determine if it communicated the Balancing Authority's or Transmission Operator's Emergency to impacted Reliability Coordinators, Balancing Authorities, and Transmission Operators in accordance with Requirement R4.

R5. Each Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall initiate an Energy Emergency Alert, as detailed in Attachment 1. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

Rationale for R5: Requirement R5 was created to address the FERC directive to have the Reliability Coordinator involved to ensure that the Energy Emergency Alert gets initiated.

M5. Each Reliability Coordinator, with a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area, will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that it initiated an Energy Emergency Alert, as detailed in Attachment 1, in accordance with Requirement R5.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The Balancing Authority, Reliability Coordinator, and Transmission Operator shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Transmission Operator shall retain the current Emergency Operating Plan, plus each version issued since the last audit and evidence of compliance since the last audit for Requirement R1, and Measure M1.
- The Balancing Authority shall retain the current Emergency Operating Plan, plus each version issued since the last audit and evidence of compliance since the last audit for Requirement R2, and Measure M2.
- The Reliability Coordinator shall maintain evidence of compliance since the last audit for Requirements R3, R4 and R5 and Measures M3, M4, and M5.

If a Balancing Authority, Reliability Coordinator or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Check

Compliance Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Real-time Operations, Operations Planning**	**High**	The Transmission Operator had a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System but failed to include one of the Sub-Parts 1.2.1 - 1.2.7 as applicable.	The Transmission Operator had a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System but failed to include two of the Sub-Parts 1.2.1 - 1.2.7 as applicable.	The Transmission Operator had a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System but failed to include three of the Sub-Parts 1.2.1 - 1.2.7 as applicable. OR The Transmission Operator failed to have a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System but failed to	The Transmission Operator had a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System but failed to include four or more of the Sub-Parts 1.2.1 - 1.2.7. OR The Transmission Operator failed to have a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					include either Part 1.1 or Part 1.3. OR The Transmission Operator had a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System but failed to maintain it.	Emergencies on its Transmission System. OR The Transmission Operator had a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System but failed to implement it for an operating Emergency.
R2	**Real-time Operations, Operations Planning**	**High**	The Balancing Authority had a Reliability Coordinator-approved Emergency	The Balancing Authority had a Reliability Coordinator-approved Emergency Operating Plan to mitigate	The Balancing Authority had a Reliability Coordinator-approved Emergency	The Balancing Authority had a Reliability Coordinator-approved

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Operating Plan to mitigate Capacity and Energy Emergencies but failed to include one of the Sub-Parts 2.4.1 – 2.4.9.	Capacity and Energy Emergencies but failed to include two of the Sub-Parts 2.4.1 – 2.4.9.	Operating Plan to mitigate Capacity and Energy Emergencies but failed to include three of the Sub-Parts 2.4.1 – 2.4.9. OR The Balancing Authority had a Reliability Coordinator-approved Emergency Operating Plan to mitigate Capacity and Energy Emergencies but failed to include either Part 2.1 or Part 2.2 or Part 2.3 or Part 2.5. OR The Balancing Authority had a Reliability Coordinator-approved	Emergency Operating Plan to mitigate Capacity and Energy Emergencies but failed to include four or more of the Sub-Parts 2.4.1 – 2.4.9. OR The Balancing Authority failed to have a Reliability Coordinator-approved Emergency Operating Plan to mitigate Capacity and Energy Emergencies. OR The Balancing Authority had a Reliability

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					Emergency Operating Plan to mitigate Capacity and Energy Emergencies but failed to maintain it.	Coordinator-approved Emergency Operating Plan to mitigate Capacity and Energy Emergencies but failed to implement it for a Capacity or Energy Emergency.
R3	**Operations Planning**	**Medium**	The Reliability Coordinator approved or disapproved, with stated reasons for disapproval, a Transmission Operator and Balancing Authority submitted or revised Emergency Operating Plans in more than 30 days but less than or equal to 40 days.	The Reliability Coordinator approved or disapproved, with stated reasons for disapproval, a Transmission Operator and Balancing Authority submitted or revised Emergency Operating Plans in more than 40 days but less than or equal to 50 days.	The Reliability Coordinator approved or disapproved, with stated reasons for disapproval, a Transmission Operator and Balancing Authority submitted or revised Emergency Operating Plans in more than 50 days but less than or equal to 60 days.	The Reliability Coordinator approved or disapproved, with stated reasons for disapproval, a Transmission Operator and Balancing Authority submitted or revised Emergency Operating Plans in

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					OR The Reliability Coordinator disapproved a Transmission Operator and Balancing Authority submitted or revised Emergency Operating Plans within 30 calendar days of submittal but failed to provide the reasons for disapproval.	more than 60 days. OR The Reliability Coordinator failed to approve or disapprove, with stated reasons for disapproval, a Transmission Operator and Balancing Authority submitted or revised Emergency Operating Plans.
R4	**Real-time Operations**	**High**	N/A	N/A	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority did notify other impacted Reliability Coordinators, Balancing Authorities and Transmission	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority failed to notify, as soon as practical, other impacted Reliability Coordinators,

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					Operators but did not do so as soon as practical.	Balancing Authorities and Transmission Operators.
R5	**Real-time Operations**	**High**	N/A	The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to notify the other Reliability Coordinators, Balancing Authorities and Transmission Operators when the alert has ended.	The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to initiate an Energy Emergency Alert and hold conference calls between Reliability Coordinators as necessary to communicate System conditions.	The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to initiate an Energy Emergency Alert and notify all other Reliability Coordinators of the situation via the Reliability Coordinator Information System (RCIS). OR

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to initiate an Energy Emergency Alert and notify all Balancing Authorities and Transmission Operators in its reliability area.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Attachment 1-EOP-011-1
Energy Emergency Alerts

Introduction

This Attachment provides the process and descriptions of the levels used by the Reliability Coordinator (RC) in which it communicates the condition of a Balancing Authority (BA) which is experiencing an Energy Emergency.

A. General Responsibilities

1. **Initiation by RC.** An Energy Emergency Alert (EEA) may be initiated only by a RC at 1) the RC's own request, or 2) upon the request of the requesting BA.
2. **Notification**. A RC who declares an EEA shall notify all BAs and Transmission Operators (TOP) in its Reliability Coordinator Area. The RC shall also notify all other RCs of the situation via the Reliability Coordinator Information System (RCIS). Additionally, conference calls between RCs shall be held as necessary to communicate System conditions. The RC shall also notify the other RCs, Bas, and TOPs when the EEA has ended.

B. EEA Levels

Introduction

To ensure that all RCs clearly understand potential and actual Energy Emergencies in the Interconnection, NERC has established four levels of EEAs. The RCs will use these terms when explaining Energy Emergencies to each other. An EEA is an Emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC reliability standard. The RC may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.

1. **EEA 1 — All available generation resources in use.**

Circumstances:

- Requesting BA is experiencing conditions where all available generation resources are committed to meet firm Load, firm transactions, and reserve commitments, and is concerned about sustaining its required Operating Reserves.
- Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

2. **EEA 2 — Load management procedures in effect**.

Circumstances:

- Requesting BA is no longer able to provide its customers' expected energy requirements.
- Requesting BA has implemented its approved Emergency Operations Plan.

During EEA 2, RCs and requesting BAs have the following responsibilities:

2.1 **Notifying other BAs and market participants**. The requesting BA shall communicate its needs to other BAs and market participants. Upon request from the requesting BA, the respective RC shall post the declaration of the alert level, along with the name of the requesting BA on the RCIS website.

2.2 Declaration period. The requesting BA shall update its RC of the situation at a minimum of every hour until the EEA 2 is terminated. The RC shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the impacted RCs, BAs and TOPs**.**

2.3 Sharing information on resource availability. A BA with available resources shall contact the requesting BA and coordinate with the RC as appropriate.

2.4 Evaluating and mitigating Transmission limitations. The RC shall review Transmission outages and work with the TOP to see if it's possible to return the Transmission element that may relieve the Loading on System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs).

2.5 BA actions. Before declaring an EEA 3, the requesting BA must make use of all available resources; this includes, but is not limited to:

2.5.1 All available generation units are on line. All generation capable of being on line in the time frame of the Emergency is on line, including quick-start and peaking units not being held for contingency reserves, regardless of cost.

2.5.2 Demand-Side Management curtailed. Initiate Demand Side Management within provisions of any applicable agreements not being held for contingency reserves.

3. EEA 3 — Inability to meet Operating Reserve requirement or Firm Load interruption is imminent or in progress.

Circumstances:

- Requesting BA is unable to meet Operating Reserve requirements and foresees a need for possible interruption of firm Load.

During EEA 3, RCs and BAs have the following responsibilities:

3.1 Continue actions from EEA 2. The RCs and the requesting BA shall continue to take all actions initiated during EEA 2.

3.2 Operating Reserves. Operating Reserves are being utilized such that the requesting BA is carrying reserves below the required minimum or has initiated Emergency assistance through its Operating Reserve sharing program. In this situation, the requesting BA must be able to shed an amount of firm Load in order to meet its Operating Reserve requirement.

3.3 Declaration Period. The BA shall update its RC of the situation at a minimum of every hour until the EEA 3 is terminated. The RC shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the impacted BAs and TOPs.

3.4 Reevaluating and revising SOLs and IROLs. The RC shall evaluate the risks of revising SOLs and IROLs for the possibility of delivery of energy to the requesting BA.

Reevaluation of SOLs and IROLs shall be coordinated with other RCs and only with the agreement of the TOP whose equipment would be affected. SOLs and IROLs shall only be revised as long as an EEA 3 condition exists, or as allowed by the TOP whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:

3.4.1 Requesting BA obligations. The requesting BA must agree that, upon notification from its RC of the situation, it will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include Load shedding.

3.5 Returning to pre-Emergency conditions. Whenever energy is made available to a requesting BA such that the Transmission Systems can be returned to its pre-Emergency SOLs or IROLs condition, the requesting BA shall request the RC to downgrade the alert level.

3.5.1 Notification of other parties. Upon notification from the requesting BA that an alert has been downgraded, the RC shall notify the impacted RCs (via the RCIS), BAs and TOPs that its Systems can be returned to its normal limits.

Alert 0 - Termination. When the requesting BA is able to meet its Load and Operating Reserve requirements, it shall request its RC to terminate the EEA**.**

0.1 Notification. The RC shall notify all other RCs via the RCIS of the termination. The RC shall also notify the impacted BAs and TOPs.

Guidelines and Technical Basis

Rationales to be added here after balloting.

Requirement R1:

Requirement R2:

Requirement R3:

Requirement R4:

Requirement R5: