Aquila, Inc. – Carl A Huslig

Aquila suggests that the original wording from Policy 3A 2.1 should be used in the Version 0 Standard.

Consideration:

The drafting team modified INT-001 Requirement 2.2 in the errata sheet because the Interchange Subcommittee commented on a conflict introduced by lumping into the same requirement emergency transactions to address SOL and IROL limit violations and transactions used to replace a loss of generation. Emergency transactions to address SOL or IROL limit violations have different tagging requirements that are addressed in INT-004 Requirement 1.

In making this correction, the drafting team had to make an interpretation regarding what the intended requirement was for tagging emergency transactions to replace a generation loss. The drafting team consulted with the Interchange Subcommittee to determine the original intent of the Policy 3 language. On that basis, the drafting team proposed the following requirement in the errata sheet for INT-001 Requirement 2.2:

If the duration of the Emergency Transaction to replace the generation loss is less than 60 minutes, then the Transaction shall be exempt from tagging.

This compares to Operating Policy 3A 2.1, which states:

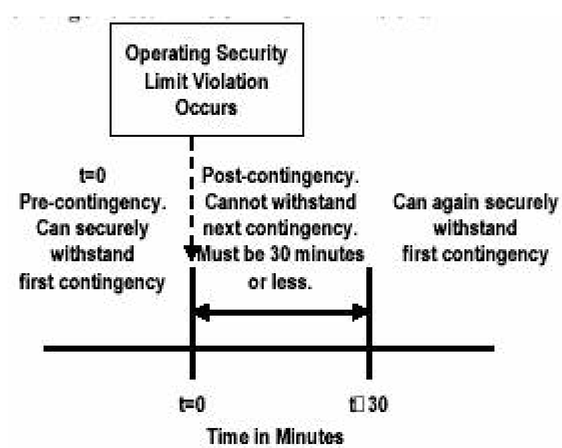
INTERCHANGE TRANSACTIONS *established to replace unexpected generation loss, such as through prearranged reserve sharing agreements or other arrangements, are exempt from tagging for 60 minutes from the time at which the* INTERCHANGE TRANSACTION *begins.*

One difference between the policy and the proposed standard is whether the exemption should apply if the transaction is 'less than 60 minutes' in duration, rather than '60 minutes or less'. This seemingly small difference is significant if a common practice is to schedule the replacement transaction for 60 minutes. There are other ambiguities regarding what emergency transactions have to be tagged and when.

Recognizing there is not a single agreed upon interpretation of the existing policy and no opportunity at this point to vet alternative views in the Version 0 standards, the drafting team is leaving the requirement as currently stated in the errata sheet. The drafting team recommend that the Interchange Subcommittee immediately prepare a SAR to propose revisions to address the remaining ambiguities before, or as soon as possible after, the implementation of the Version 0 standards.

Robert Blohm

I revoice my concern below about crucial wording in Policy 2 that was omitted from version-0 of IROL Standard 8.



The all-important wording "Cannot withstand next contingency" that exempts multiple-contingency recovery during the 30-minute recovery period in the Policy 2 diagram (below) in section A.1.1 entitled "Multiple Outages" was never translated into the version-0 IROL Standard 8.0. Only the following wording of section A.1 entitled "Return from Operating Security Limit Violation" was translated into the version-0 Standard: "Following a contingency or other event that results in an Operating Security Limit violation, the Control Area shall return its transmission system to within Operating Security Limits as soon as possible, but no longer than 30 minutes." This omission of a critical specification made in the diagram but not in the text of Policy 2 makes the version-0 IROL Standard 8.0 **incomplete and in error**. The diagram was not just an "illustration": it "specified" this information crucial to reliable operating practice. Instead, the current version-0 IROL Standard 8.0 will make or justify operator practice of unnecessarily, and therefore possibly unreliably, over-controlling the system so as to be able to "withstand" one or more additional contingencies within 30 minutes of the first contingency. Current Policy 2 specifies an exact degree of control that can withstand only the first contingency during the initial 30 minute recovery period, not further contingencies that may occur during that period. The current version-0 IROL Standard 8.0 firstly misrepresents Policy 2 by being *less determinate* than Policy 2 and therefore sanctioning overly-tight control in the case of multiple contingencies that was specifically excluded in the diagram wording in Policy 2, and secondly is inconsistent with Policy 1 and with version-0 DCS Standard 2.0 that explicitly exempts multiple-contingency recovery. Accordingly, the Drafting Team was incorrect in the following response it made to this observation submitted in the comments to Draft 2 of the version-0 IROL Standard 8.0, namely "Direct translation. Omitting figure does not affect standard."

Consideration:

The drafting team appreciates the concerns that have been raised here again. However, the drafting team believes the diagram was illustrative and did not specify a requirement or exemption from a requirement. The IROL task force in its work has noted that the 30 minutes following a contingency is not intended as a grace period – the operating entity must take immediate actions to restore the system to first contingency conditions as soon as possible.

Bonneville Power Administration Transmission BPAT – Barbara Rehman

1. Removal of Phase III and IV standards from Version 0 is of major concern to BPA. Planning Standards I.D.S1; II.B.S1 and S2; and 3.C.S1 and S2 (from the old standards) were listed as possible violations that contributed to the August 14, 2003 Blackout. Planning Standards and Measurments III.A.S1 and M2 have been mentioned as possible violations that contributed to the Westwing disturbance on June 14, 2004. We are very concerned that these standards are not included in Version 0. Waiting for an Urgent Action SAR to remedy the issues surrounding these standards and having no standard in place in the meantime is a major concern to BPA. Given NERC’s progress so far on new standards, completing the Urgent Action process by May 2005 does not seem to be even remotely possible.

2. The R1 section of each of the new standards 051.1, 051.2, 051.3 all use the phrase “the interconnected transmission system is planned such that…”. The the old standard sections I.A.S1, S2 and S3 said “the interconnected transmission system shall be planned, designed and constructed such that…” Deleting these words dilutes the new standards considerably. The missing words should be added back in.

3. The changes listed in the “Errata on Version 0 Planning Standards Recommended by the Planning Committee and the Planning Standards Task Force (November 22, 2004) are important changes to ensure that Version 0 standards are a satisfactory translation of the existing standards. BPA supports them in their entirety.

4. BPA also has a concern that there needs to be one central process for development of standards associated with ACE. Such standards associated with generation control could have reliability implications and the decision to split these standards between NERC and NAESB should be revisited.

Consideration:

1. During the posting of the SAR for the Version 0 Reliability Standards, several entities included comments indicating that several of the Phase 3 and Phase 4 Planning Standards should not be included in Version 0 because they needed additional work. During the postings of the drafts 1 and 2 of the Version 0 standards, many commenters indicated that several of the Phase 3 and Phase 4 standards would be 'show stoppers' if included in Version 0. In addition, the SAC advised the drafting team to include in Version 0 those requirements that would be implemented, and compliance expected, when adopted by the Board. The drafting recommended, and the SAC supported, addressing these Phase 3 and Phase 4 Planning Standards as part of the Version 1 standards development process, with a commitment to push these forward as rapidly as possible. To this end, the necessary SARs and a solicitation for drafting team members have already been posted. The team will have a target of developing the replacement standards by May 2005, only one month after the implementation of the Version 0 standards. The urgent action process was rejected because standards under this process are currently only valid for one year.
2. The drafting made a good faith effort to evenly translate the planning standard's existing requirements. There are no approved planning standards that contain requirements for 'construction'. While the word, 'constructed' did appear in the 'S' statements, this was viewed as a high level goal or purpose, but there was no specific requirement or measure requiring construction of facilities and that is why such requirements were not added in Version 0.
3. The SDT gave careful consideration to the proposed Planning Standards TF errata, and accepted those that were within the scope of Version 0 standards.
4. The Version 0 standards related to resource and load balancing address the minimum criteria for what has to be achieved for reliability, and how reliability data are reported, but does not attempt to specify how the criteria are met. The ACE special equations, the time error correction procedure and the inadvertent payback procedure describe methods for achieving the reliability criteria, but these methods are not exclusive of other practices that could achieve the same result. Inadvertent interchange payback, in fact, had already been assigned to NAESB for development prior to the start of the Version 0 project. The drafting team had noticed the proposal to assign these items to NAESB for development and the industry comments supported showed strong support for this proposal. It may be more efficient in the future if standards related to control performance are developed in a single organization and the commenter may wish to pursue that concept. The drafting team would also recommend that the Joint Interface Committee establish formal criteria that it uses to determine whether a standard should be assigned as a reliability standard or a business practice standard.

Bonneville Power Administration - Power Business – Francis J Halpin

I would like to submit the following comments with my yes vote on version 0:

1. Removal of Phase III and IV standards from Version 0 is of major concern to BPA. Planning Standards I.D.S1; II.B.S1 and S2; and 3.C.S1 and S2 (from the old standards) were listed as possible violations that contributed to the August 14, 2003 Blackout. Planning Standards and Measurements III.A.S1 and M2 have been mentioned as possible violations that contributed to the Westwing disturbance on June 14, 2004. We are very concerned that these standards are not included in Version 0. Waiting for an Urgent Action SAR to remedy the issues surrounding these standards and having no standard in place in the meantime is a major concern to BPA. Given NERC's progress so far on new

standards, completing the Urgent Action process by May 2005 does not seem to be even remotely possible.

2. The R1 section of each of the new standards 051.1, 051.2, 051.3 all use the phrase "the interconnected transmission system is planned such that…". The old standard sections I.A.S1, S2 and S3 said "the interconnected transmission system shall be planned, designed and constructed such that…" Deleting these words dilutes the new standards considerably. The missing words should be added back in.
3. The changes listed in the "Errata on Version 0 Planning Standards Recommended by the Planning Committee and the Planning Standards Task Force (November 22, 2004) are important changes to ensure that Version 0 standards are a satisfactory translation of the existing standards. BPA supports them in their entirety.
4. BPA also has a concern that parts of Area Control Area (ACE) have been placed in the NAESB court. BPA feels that there needs to be one central process for development of standards associated with ACE. Such standards associated with generation control and which are intricate parts of AGC algorithms in EMS systems have direct reliability implications.
5. BPA would like to see the decision to split these standards between NERC and NAESB revisited and ultimately returned to NERC to be developed as Reliability standards

Consideration:

1. During the posting of the SAR for the Version 0 Reliability Standards, several entities included comments indicating that several of the Phase 3 and Phase 4 Planning Standards should not be included in Version 0 because they needed additional work. During the postings of the drafts 1 and 2 of the Version 0 standards, many commenters indicated that several of the Phase 3 and Phase 4 standards would be 'show stoppers' if included in Version 0. In addition, the SAC advised the drafting team to include in Version 0 those requirements that would be implemented, and compliance expected, when adopted by the Board. The drafting recommended, and the SAC supported, addressing these Phase 3 and Phase 4 Planning Standards as part of the Version 1 standards development process, with a commitment to push these forward as rapidly as possible. To this end, the necessary SARs and a solicitation for drafting team members have already been posted. The team will have a target of developing the replacement standards by May 2005, only one month after the implementation of the Version 0 standards. The urgent action process was rejected because standards under this process are currently only valid for one year.
2. The drafting made a good faith effort to evenly translate the planning standard's existing requirements. There are no approved planning standards that contain requirements for 'construction'. While the word, 'constructed' did appear in the 'S' statements, this was viewed as a high level goal or purpose, but there was no specific requirement or measure requiring construction of facilities and that is why such requirements were not added in Version 0.
3. The SDT gave careful consideration to the proposed Planning Standards TF errata, and accepted those that were within the scope of Version 0 standards.
4. The Version 0 standards related to resource and load balancing address the minimum criteria for what has to be achieved for reliability, and how reliability data are reported, but does not attempt to specify how the criteria are met. The ACE special equations, the time error correction procedure and the inadvertent payback procedure describe methods for achieving the reliability criteria, but these methods are not exclusive of other practices

that could achieve the same result. Inadvertent interchange payback, in fact, had already been assigned to NAESB for development prior to the start of the Version 0 project. The drafting team had noticed the proposal to assign these items to NAESB for development and the industry comments supported showed strong support for this proposal. It may be more efficient in the future if standards related to control performance are developed in a single organization and the commenter may wish to pursue that concept. The drafting team would also recommend that the Joint Interface Committee establish formal criteria that it uses to determine whether a standard should be assigned as a reliability standard or a business practice standard.

Bonneville Power Administration - Power Business – Brenda S. Anderson

Version 0 standards should be approved with the following comments:

1. Removal of Phase III and IV standards from Version 0 is of major concern to BPA. Planning Standards I.D.S1; II.B.S1 and S2; and 3.C.S1 and S2 (from the old standards) were listed as possible violations that contributed to the August 14, 2003 Blackout. Planning Standards and Measurments III.A.S1 and M2 have been mentioned as possible violations that contributed to the Westwing disturbance on June 14, 2004. We are very concerned that these standards are not included in Version 0. Waiting for an Urgent Action SAR to remedy the issues surrounding these standards and having no standard in place in the meantime is a major concern to BPA. Given NERC's progress so far on new standards, completing the Urgent Action process by May 2005 does not seem to be even remotely possible.
2. The R1 section of each of the new standards 051.1, 051.2, 051.3 all use the phrase "the interconnected transmission system is planned such that…". The the old standard sections I.A.S1, S2 and S3 said "the interconnected transmission system shall be planned, designed and constructed such that…" Deleting these words dilutes the new standards considerably. The missing words should be added back in.
3. The changes listed in the "Errata on Version 0 Planning Standards Recommended by the Planning Committee and the Planning Standards Task Force (November 22, 2004) are important changes to ensure that Version 0 standards are a satisfactory translation of the existing standards. BPA supports them in their entirety.
4. BPA is also concerned that some of the standards that have been moved to NAESB have reliability impacts and if moved to NAESB are voluntary.

Consideration:

1. During the posting of the SAR for the Version 0 Reliability Standards, several entities included comments indicating that several of the Phase 3 and Phase 4 Planning Standards should not be included in Version 0 because they needed additional work. During the postings of the drafts 1 and 2 of the Version 0 standards, many commenters indicated that several of the Phase 3 and Phase 4 standards would be 'show stoppers' if included in Version 0. In addition, the SAC advised the drafting team to include in Version 0 those requirements that would be implemented, and compliance expected, when adopted by the Board. The drafting recommended, and the SAC supported, addressing these Phase 3 and Phase 4 Planning Standards as part of the Version 1 standards development process, with a commitment to push these forward as rapidly as possible. To this end, the necessary SARs and a solicitation for drafting team members have already been posted. The team will have a target of developing the replacement standards by May 2005, only one month after the implementation of the Version 0 standards. The urgent action process was rejected because standards under this process are currently only valid for one year.

2. The drafting made a good faith effort to evenly translate the planning standard's existing requirements. There are no approved planning standards that contain requirements for 'construction'. While the word, 'constructed' did appear in the 'S' statements, this was viewed as a high level goal or purpose, but there was no specific requirement or measure requiring construction of facilities and that is why such requirements were not added in Version 0.
3. The SDT gave careful consideration to the proposed Planning Standards TF errata, and accepted those that were within the scope of Version 0 standards.
4. The Version 0 standards related to resource and load balancing address the minimum criteria for what has to be achieved for reliability, and how reliability data are reported, but does not attempt to specify how the criteria are met. The ACE special equations, the time error correction procedure and the inadvertent payback procedure describe methods for achieving the reliability criteria, but these methods are not exclusive of other practices that could achieve the same result. Inadvertent interchange payback, in fact, had already been assigned to NAESB for development prior to the start of the Version 0 project. The drafting team had noticed the proposal to assign these items to NAESB for development and the industry comments supported showed strong support for this proposal. It may be more efficient in the future if standards related to control performance are developed in a single organization and the commenter may wish to pursue that concept. The drafting team would also recommend that the Joint Interface Committee establish formal criteria that it uses to determine whether a standard should be assigned as a reliability standard or a business practice standard.

Bonneville Power Administration - BPAP – Terry Larson

Version 0 standards should be approved with the following comments:

1. Removal of Phase III and IV standards from Version 0 is of major concern to BPA. Planning Standards I.D.S1; II.B.S1 and S2; and 3.C.S1 and S2 (from the old standards) were listed as possible violations that contributed to the August 14, 2003 Blackout. Planning Standards and Measurments III.A.S1 and M2 have been mentioned as possible violations that contributed to the Westwing disturbance on June 14, 2004. We are very concerned that these standards are not included in Version 0. Waiting for an Urgent Action SAR to remedy the issues surrounding these standards and having no standard in place in the meantime is a major concern to BPA. Given NERC's progress so far on new standards, completing the Urgent Action process by May 2005 does not seem to be even remotely possible.
2. The R1 section of each of the new standards 051.1, 051.2, 051.3 all use the phrase "the interconnected transmission system is planned such that…". The the old standard sections I.A.S1, S2 and S3 said "the interconnected transmission system shall be planned, designed and constructed such that…" Deleting these words dilutes the new standards considerably. The missing words should be added back in.
3. The changes listed in the "Errata on Version 0 Planning Standards Recommended by the Planning Committee and the Planning Standards Task Force (November 22, 2004) are important changes to ensure that Version 0 standards are a satisfactory translation of the existing standards. BPA supports them in their entirety.
4. BPA is also concerned that some of the standards that have been moved to NAESB have reliability impacts and if moved to NAESB are voluntary.

Consideration:

1. During the posting of the SAR for the Version 0 Reliability Standards, several entities included comments indicating that several of the Phase 3 and Phase 4 Planning Standards should not be included in Version 0 because they needed additional work. During the postings of the drafts 1 and 2 of the Version 0 standards, many commenters indicated that several of the Phase 3 and Phase 4 standards would be ‘show stoppers’ if included in Version 0. In addition, the SAC advised the drafting team to include in Version 0 those requirements that would be implemented, and compliance expected, when adopted by the Board. The drafting recommended, and the SAC supported, addressing these Phase 3 and Phase 4 Planning Standards as part of the Version 1 standards development process, with a commitment to push these forward as rapidly as possible. To this end, the necessary SARs and a solicitation for drafting team members have already been posted. The team will have a target of developing the replacement standards by May 2005, only one month after the implementation of the Version 0 standards. The urgent action process was rejected because standards under this process are currently only valid for one year.
2. The drafting made a good faith effort to evenly translate the planning standard’s existing requirements. There are no approved planning standards that contain requirements for ‘construction’. While the word, ‘constructed’ did appear in the ‘S’ statements, this was viewed as a high level goal or purpose, but there was no specific requirement or measure requiring construction of facilities and that is why such requirements were not added in Version 0.
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Calpine Power Management – Jim Stanton

I believe this is a critical first step towards getting enforceable, comprehensive and meaningful Reliability Standards established. The Drafting Team should be commended for its fine work.

Consideration:

The SDT appreciates your support of Version 0.

Carolina Power & Light Company CPL – Verne Ingersoll

Progress Energy expressed in comments to the North American Electric Reliability Council (NERC) on Draft 2 of the proposed Version 0 Reliability Standards our concern that neither the functional model nor the proposed Version 0 standards should be allowed to impede the ability of utilities to fulfill their electric service obligations under state law. We further expressed our concern that the proposed Version 0 standards and the planned functional entity registration not be used by NERC to dictate a particular industry structure or to limit who may register as functional entities. We expressed to you that in many areas of the country, including the Southeast, the responsibility, authority, control and liability for the operation of the electric system as a whole is granted by the states to the utilities as a part of their utility franchise. While the utility may contract for certain tasks to be performed by another entity, such as a Reliability Coordinator, it may not delegate final authority, control, responsibility or liability to another entity without the prior approval of the state.

With the above in mind, Progress Energy's vote is cast in reliance upon the representations made by the North American Electric Reliability Council ("NERC") in a letter dated November 5, 2004 to all Regional Managers that "Registration should not be seen as prescribing organizational structures, responsibilities, or relationships. The registration is simply recording which organizations are responsible for meeting the Version 0 reliability standards and ensuring that all reliability requirements are addressed in each area of an Interconnection." Consistent with this commitment by NERC it is understood that NERC will place no restrictions or limitations on the registration of entities to perform functions in accordance with these standards.

Further, this vote is made in reliance upon the NERC's Post-Conference Comments filed with the Federal Energy Regulatory Commission in Docket No. PL04-13-000. In particular, the comments contained in Section 6 entitled "Correction of Inaccuracies Regarding Requirements for Load Shedding and Operating Tools.", which bring additional clarity to the responsibilities and authorities of the Reliability Coordinators and the operating entities (control areas and transmission operators). In particular, the comments contained in Section 6 entitled "Correction of Inaccuracies Regarding Requirements for Load Shedding and Operational Tools" state "that Operating Policy 9 (which is the genesis of Version 0) does not contain an absolute imperative that control areas blindly follow directives from a reliability coordinator".

Consideration:

The Version 0 Reliability Standards adopt the identical requirements that Reliability Coordinators have today in the current NERC Operating Policy 9. The Version 0 Reliability Standards, and the associated request to register organizations as responsible entities, do not prescribe any particular organizational structure, authorities, responsibilities, or relationships. The standards simply define the minimum requirements for the reliable planning and operation of bulk electric systems. These requirements are neutral with respect to organizational structures that are necessary or appropriate to meet the reliability requirements. Furthermore, Standard IRO-001 Requirement 8 specifically exempts an entity from following a directive of a Reliability Coordinator if such an action would "*violate safety, equipment, or regulatory or statutory requirements.*"

CenterPoint Energy – Paul Rocha

We are voting against the version 0 standards because, in our opinion, phase III and phase IV standards should be included as existing standards in version 0. To not include these standards effectively rules that, in the 8 (almost 9) years following the 1996 western state blackouts, the NERC process has failed to produce legitimate standards to address issues such as requiring generator AVRs to be in-service regulating voltage, for example. Even if there are concerns with the some of the phase 3 and 4 standards, we believe such concerns should be addressed through SARs requesting revisions, as is currently happening with the transmission planning standards.

Nevertheless, we will respect the outcome of this vote, whatever it may be.

Consideration:

During the posting of the SAR for the Version 0 Reliability Standards, several entities included comments indicating that several of the Phase 3 and Phase 4 Planning Standards should not be included in Version 0 because they needed additional work. During the postings of the drafts 1 and 2 of the Version 0 standards, many commenters indicated that several of the Phase 3 and Phase 4 standards would be 'show stoppers' if included in Version 0. In addition, the SAC advised the drafting team to include in Version 0 those requirements that would be implemented, and compliance expected, when adopted by the Board. The drafting recommended, and the SAC supported, addressing these Phase 3 and Phase 4 Planning Standards as part of the Version 1 standards development process, with a commitment to push these forward as rapidly as possible. To this end, the necessary SARs and a solicitation for drafting team members have already been posted. The team will have a target of developing the replacement standards by May 2005, only one month after the implementation of the Version 0 standards.

Cinergy – Doug Hils

Cinergy votes in favor of the Version 0 Standards with the inclusion of the errata sheet. We appreciate the effort made by the Version 0 Drafting Team, the various NERC subcommittees, and the electric industry to compile this comprehensive package. Though we believe that certain changes to the Standards may be needed in future revisions, we believe that the industry needs this starting point to work from. Most importantly, Cinergy believes that the Measures still to be developed for the Standards must go through a thorough stakeholder process to ensure that the Measures are consistent with the Standards.

Consideration:

The SDT appreciates your support and will ensure that the changes identified on the errata sheet are implemented prior to being presented to the NERC BOT for adoption. The drafting team was assigned to translate the existing policies, standards, and compliance templates without adding new measures where they did not exist. The drafting team agrees that new measures and compliance information must be developed on a priority basis through a stakeholder process.

Cinergy Corporation – Walter L Yeager

Cinergy votes in favor of the Version 0 Standards with the inclusion of the errata sheet. We appreciate the effort made by the Version 0 Drafting Team, the various NERC subcommittees, and the electric industry to compile this comprehensive package. Though we believe that certain changes to the Standards may be needed in future revisions, we believe that the industry needs this starting point to work from. Most importantly, Cinergy believes that the Measures still to be developed for the Standards must go through a thorough stakeholder process to ensure that the Measures are consistent with the Standards.

Consideration:

The SDT appreciates your support and will ensure that the changes identified on the errata sheet are implemented prior to being presented to the NERC BOT for adoption. The drafting team was assigned to translate the existing policies, standards, and compliance templates without adding new measures where they did not exist. The drafting team agrees that new measures and compliance information must be developed on a priority basis through a stakeholder process.

Con Edison Company of New York CEPD – Vinod Kotecha

Approval of the Version 0 Standards is based upon the understanding that the following changes will be incorporated in the revised standards:

We are in agreement with NPCC and support the comments provided by NPCC representatives at NERC meetings including the following:

Although the drafting team attempted to include the "S" or Standard language statements in the Requirements section, NPCC still believes some deficiency may exist and requests the language, as it exists in the Planning Standards, be directly brought into the Version 0 standards. There remains vagueness in the application of Interconnection Reliability Operating Limits (IROL) and guidelines for how it is calculated. The RC has been designated as being responsible for maintaining the interconnection within IROLs, however debate on how these should be calculated continues. There is also some concern about the lack of well-defined compliance metrics for some of the operating related standards as well as the absence of levels of non-compliance. It is not clear how the compliance assessment process will work during evaluations of compliance with these particular standards. During the Version 0 web cast, it was indicated that the compliance program for the Version 0 set would initially remain unchanged from this year's program, "initially" until additional measures could be added. This is a satisfactory step and is supported. As the compliance program expands beyond the scope of this year's program it was stated that additional program compliance metrics/measures and levels will go through the NERC Reliability Standards Process. Also, it should be reiterated that non-monetary sanctions and levels of non- compliance with associated letters/notifications of increasing severity are a more effective means of achieving compliance. In addition, to the general comments given above, here are some specific changes that need to be incorporated: TPL001 System Performance Assessment Under Normal Conditions Table 1 - Item C 5. The table is not clear and goes beyond the present double circuit outage criteria. It has been changed to any two circuits on a multiple circuit tower line. Existing Regional Criteria should be allowed to adopt appropriate rules for existing conditions. Table 1 Items 6, 7, 8, and 9 need to have a footnote that states that they do not apply to generator breaker failure conditions. Secondly, the typo relating to mix up in numbering sequence needs to be corrected. Table 1 Footnote b last sentence states: "To prepare for the next contingency, system adjustments are permitted, including curtailment of contracted Firm electric power transfers". The issue here is "should you curtail firm deliveries ahead of time or should you curtail them only after a contingency occurs"?

1. Table 1 D Item 11 - Remove "major Load center" because it's not clear as to what constitutes a major load center".
2. PL 004 R.1.3.9 : Remove from the Extreme Bulk Electric System (BES) Events because extreme contingencies should not limit maintenance or facility repairs after outage conditions.
3. FAC-002-0 B R1. "Power Pool?". Should also include ISO and RTOs.
4. FAC-001-0 Compliance Item 1.2. Five business days may be too onerous for Facility Connection Requirements. Suggest revision to at least 30 days.
5. MOD-001-0 Requirements
   - Item R.1.7 will depend upon the dispatch. In most cases an RRO does not have the "bids" or cannot access them so how is this work to be performed? Please clarify.
   - Without having the "bid" data, the Transmission Provider cannot meet the "Requirement" unless NERC is willing to say that the bids will be provided to TOs and TPs.
6. MOD 004-0
   1. Item BR1.3 is too restrictive. Why should the Transmission Service Provider's CBM be restricted to those units within the Transmission Service Provider's System is not clear. Suppose a large generating plant in an adjacent system causes more of a

problem to the Transmission Service Provider? It should have the right to look at the worst generator contingency affecting its facilities.

7. MOD-011-0 B Requirements Item R1.1 : Security issue :

   We should not require "locations" of substations to be made public anymore. (since 9/11)

8. MOD-013 Requirement B R1.1 should be changed to read: Generator Owners shall report unit-specific dynamics data for generators....
9. PRC-004-0 Requirement B R1 : Remove the word "all".
10. PRC- 9, 10 and 11. UVLS : Under voltage load shedding should not be a requirement for all parties. Those who have shunt reactors can meet the objective by not shedding load but by shedding shunt reactors. Flexibility in achieving the desired goal is appropriate.
11. NERC needs to devise a method to keep all the requested information confidential and secure as in can be mis-used if it falls in the wrong hands.
12. Definitions: TRM definition is missing.
13. There should be a statement that entities may have more stringent standards than Version 0.

Consideration:

1-10 - The suggestions made in items 1 through 10 all require modifications to the intent of existing standards.

11. This is not a suggestion for a modification to Version 0 – it is a suggestion for a modification to a NERC administrative process and is outside the scope of the SDT.
12. The definition of TRM was missing from the posted glossary, but was included on the errata sheet.
13. NERC does not preclude any entity from developing standards that are more stringent than NERC's Reliability Standards. The NERC Reliability Standards Process Manual includes the following language, which clarifies that Regions may develop standards that are more stringent than NERC Reliability Standards:

    "Regions may develop, through their own processes, separate Regional Standards that go beyond, add detail to, or implement NERC Organization Standards, or that cover matters not addressed in NERC Organization Standards."

Con Edison Company of New York CEPD – Norman Mah

Our approval of the Version 0 Standards is based upon the understanding that the following changes will be incorporated in the revised standards:

We are in agreement with NPCC and support the comments provided by NPCC representatives at NERC meetings including the following:

1. Table 1 D Item 11 - Remove "major Load center" because it's not clear as to what constitutes a major load center".
2. PL 004 R.1.3.9 : Remove from the Extreme Bulk Electric System (BES) Events because extreme contingencies should not limit maintenance or facility repairs after outage conditions.
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5. MOD-001-0 Requirements

– Item R.1.7 will depend upon the dispatch. In most cases an RRO does not have the "bids" or cannot access them so how is this work to be performed? Please clarify.

– Without having the "bid" data, the Transmission Provider cannot meet the "Requirement" unless NERC is willing to say that the bids will be provided to TOs and TPs.

6. MOD 004-0

2. Item BR1.3 is too restrictive. Why should the Transmission Service Provider's CBM be restricted to those units within the Transmission Service Provider's System is not clear. Suppose a large generating plant in an adjacent system causes more of a problem to the Transmission Service Provider? It should have the right to look at the worst generator contingency affecting its facilities.

7. MOD-011-0 B Requirements Item R1.1 : Security issue :

   We should not require "locations" of substations to be made public anymore. (since 9/11)

8. MOD-013 Requirement B R1.1 should be changed to read: Generator Owners shall report unit-specific dynamics data for generators....
9. PRC-004-0 Requirement B R1 : Remove the word "all".
10. PRC- 9, 10 and 11. UVLS : Under voltage load shedding should not be a requirement for all parties. Those who have shunt reactors can meet the objective by not shedding load but by shedding shunt reactors. Flexibility in achieving the desired goal is appropriate.
11. NERC needs to devise a method to keep all the requested information confidential and secure as in can be mis-used if it falls in the wrong hands.
12. Definitions: TRM definition is missing.
13. There should be a statement that entities may have more stringent standards than Version 0.

Consideration:

1-10 - The suggestions made in items 1 through 10 all require modifications to the intent of existing standards.

11. This is not a suggestion for a modification to Version 0 – it is a suggestion for a modification to a NERC administrative process and is outside the scope of the SDT.
12. The definition of TRM was missing from the posted glossary, but was included on the errata sheet.
13. NERC does not preclude any entity from developing standards that are more stringent than NERC's Reliability Standards. The NERC Reliability Standards Process Manual includes the following language, which clarifies that Regions may develop standards that are more stringent than NERC Reliability Standards:

    > "Regions may develop, through their own processes, separate Regional Standards that go beyond, add detail to, or implement NERC Organization Standards, or that cover matters not addressed in NERC Organization Standards."

Con Edison – Edwin Thompson

Our approval of the Version 0 Standards is based upon the understanding that the following changes will be incorporated in the revised standards:

We are in agreement with NPCC and support the comments provided by NPCC representatives at NERC meetings including the following:

1. Although the drafting team attempted to include the "S" or Standard language statements in the Requirements section, NPCC still believes some deficiency may exist and requests the language, as it exists in the Planning Standards, be directly brought into the Version 0 standards.
2. There remains vagueness in the application of Interconnection Reliability Operating Limits (IROL) and guidelines for how it is calculated. The RC has been designated as being responsible for maintaining the interconnection within IROLs, however debate on how these should be calculated continues.
3. There is also some concern about the lack of well-defined compliance metrics for some of the operating related standards as well as the absence of levels of non-compliance. It is not clear how the compliance assessment process will work during evaluations of compliance with these particular standards. During the Version 0 web cast, it was indicated that the compliance program for the Version 0 set would initially remain unchanged from this year's program, "initially" until additional measures could be added. This is a satisfactory step and is supported. As the compliance program expands beyond the scope of this year's program it was stated that additional program compliance metrics/measures and levels will go through the NERC Reliability Standards Process.
4. Also, it should be reiterated that non-monetary sanctions and levels of non-compliance with associated letters/notifications of increasing severity are a more effective means of achieving compliance.

* In addition, to the general comments given above, here are some specific changes that need to be incorporated :

5. TPL001 System Performance Assessment Under Normal Conditions
   Table 1 - Item C 5. The table is not clear and goes beyond the present double circuit outage criteria. It needs to be changed to state " Two adjacent circuits of a multiple circuit towerline" instead of "Any two circuits of a multiple circuit towerline".
6. Table 1 Items 6, 7, 8, and 9 need to have a footnote that states that they do not apply to generator breaker failure conditions. Secondly, the typo relating to mix up in numbering sequence needs to be corrected.
7. Table 1 Footnote b last sentence states : "To prepare for the next contingency, system adjustments are permitted, including curtailment of contracted Firm electric power transfers". The issue here is "should you curtail firm deliveries ahead of time or should you curtail them only after a contingency occurs"?
8. Table 1 D Item 11 - Remove "major Load center" because it's not clear as to what constitutes a major load center".
9. TPL 004 R.1.3.9 : Remove from the Extreme Bulk Electric System (BES) Events. because extreme contingencies should not limit maintenance or facility repairs after outage conditions.
10. FAC-002-0 B R1. "Power Pool?". Should also include ISO and RTOs.
11. FAC-001-0 Compliance Item 1.2 Five business days may be too onerous for Facility Connection Requirements. Suggest revision to at least 30 days.

12. MOD-001-0 Requirements
    Item R.1.7 will depend upon the dispatch. In most cases an RRO does not have the "bids" or cannot access them so how is this work to be performed? Please clarify.
    Without having the "bid" data, the Transmission Provider cannot meet the "Requirement" unless NERC is willing to say that the bids will be provided to TOs and TPs.
13. MOD 004-0
    Item BR1.3 is too restrictive. Why should the Transmission Service Provider's CBM be restricted to those units within the Transmission Service Provider's System is not clear. Suppose a large generating plant in an adjacent system causes more of a problem to the Transmission Service Provider? It should have the right to look at the worst generator contingency affecting its facilities.
14. MOD-011-0 B Requirements Item R1.1 : Security issue :
    We should not require "locations" of substations to be made public anymore. (since 9/11)
    MOD-013 Requirement B R1.1 should be changed to read: Generator Owners shall report unit-specific dynamics data for generators....
15. PRC-004-0 Requirement B R1 : Remove the word "all".
16. PRC- 9, 10 and 11. UVLS : Under voltage load shedding should not be a requirement for all parties. Those who have shunt reactors can meet the objective by not shedding load but by shedding shunt reactors. Flexibility in achieving the desired goal is appropriate.
17. NERC needs to devise a method to keep all the requested information confidential and secure as in can be mis-used if it falls in the wrong hands.
18. Definitions : TRM definition is missing.
19. There should be a statement that entities may have more stringent standards than Version 0.

Consideration:

1. The SDT developed a table to show how the ‘S’ statements from the Planning Standards were considered in developing the associated Version 0 Standards. There were several cases where the language in one of the ‘S’ statements implied a level of performance that was not supported by its associated requirements or measures. In each case where a conflict existed between the implied performance standard as stated in the ‘S’ statement, and the performance specified in the requirements and measures, the SDT defaulted to using language from requirements and measures.
2. The issue of clarifying the requirements for calculating IROL was known prior to the start of the Version 0 standards development. A task force has been working on the issue and is expected to propose improvements to the standards. However, the Version 0 drafting team, charged with translating the existing standards, could not undertake to propose such improvements. The issue is particularly complex and requires more extensive industry input than was possible in the expedited time frame of the Version 0 standards.
3. The drafting team was assigned to translate the existing policies, standards, and compliance templates without adding new measures where they did not exist. The drafting team agrees that new measures and compliance information must be developed on a priority basis through a stakeholder process.
4. The definition of penalties and sanctions was outside the scope of the Version 0 standards, since there is no current provision for their implementation.

5-16 all require modifications to the intent of existing standards and are outside the scope of the SDT.

6. The typo in Table 1 that resulted in improper numbering of Category C events will be fixed.

17. This is not a suggestion for a modification to Version 0 – it is a suggestion for a modification to a NERC administrative process and is outside the scope of the SDT.

18. The definition of TRM was missing from the posted glossary, but was included on the errata sheet.

19. Agreed. NERC does not preclude any entity from developing standards that are more stringent than NERC's Reliability Standards. The NERC Reliability Standards Process Manual includes the following language, which clarifies that Regions may develop standards that are more stringent than NERC Reliability Standards:

    "Regions may develop, through their own processes, separate Regional Standards that go beyond, add detail to, or implement NERC Organization Standards, or that cover matters not addressed in NERC Organization Standards."

Con Edison Company of New York CEPD – Rebecca Adrienne Craft

Our approval of the Version 0 Standards is based upon the understanding that the following changes will be incorporated in the revised standards:
We are in agreement with NPCC and support the comments provided by NPCC representatives at NERC meetings including the following:

1. Although the drafting team attempted to include the "S" or Standard language statements in the Requirements section, NPCC still believes some deficiency may exist and requests the language, as it exists in the Planning Standards, be directly brought into the Version 0 standards.

2. There remains vagueness in the application of Interconnection Reliability Operating Limits (IROL) and guidelines for how it is calculated. The RC has been designated as being responsible for maintaining the interconnection within IROLs, however debate on how these should be calculated continues.

3. There is also some concern about the lack of well-defined compliance metrics for some of the operating related standards as well as the absence of levels of non-compliance. It is not clear how the compliance assessment process will work during evaluations of compliance with these particular standards. During the Version 0 web cast, it was indicated that the compliance program for the Version 0 set would initially remain unchanged from this year's program, "initially" until additional measures could be added. This is a satisfactory step and is supported. As the compliance program expands beyond the scope of this year's program it was stated that additional program compliance metrics/measures and levels will go through the NERC Reliability Standards Process.

4. Also, it should be reiterated that non-monetary sanctions and levels of non-compliance with associated letters/notifications of increasing severity are a more effective means of achieving compliance.

    In addition, to the general comments given above, here are some specific changes that need to be incorporated :

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Consideration:

1. The SDT developed a table to show how the 'S' statements from the Planning Standards were considered in developing the associated Version 0 Standards. There were several cases where the language in one of the 'S' statements implied a level of performance that was not supported by its associated requirements or measures. In each case where a conflict existed between the implied performance standard as stated in the 'S' statement, and the performance specified in the requirements and measures, the SDT defaulted to using language from requirements and measures.
2. The issue of clarifying the requirements for calculating IROL was known prior to the start of the Version 0 standards development. A task force has been working on the issue and is expected to propose improvements to the standards. However, the Version 0 drafting team, charged with translating the existing standards, could not undertake to propose such improvements. The issue is particularly complex and requires more extensive industry input than was possible in the expedited time frame of the Version 0 standards.
3. The drafting team was assigned to translate the existing policies, standards, and compliance templates without adding new measures where they did not exist. The drafting team agrees that new measures and compliance information must be developed on a priority basis through a stakeholder process.
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    "Regions may develop, through their own processes, separate Regional Standards that go beyond, add detail to, or implement NERC Organization Standards, or that cover matters not addressed in NERC Organization Standards."

Duke Power – Greg Stone

Thanks to the drafting team. They have helped 'move the ball forward' on behalf of the industry.

Development of these Standards has highlighted several process related questions:

1) How much latitude does a drafting team - even if under the direction of the SAC - have to deviate from the SAR;

2) Implementation plans associated with a Standard can be as important as the Standard itself. Since implementation plans are not included in the ballot process, how can the industry be assured such plans will not be changed after a Standard is approved;

3) What is the current plan for retaining 30+ years of industry "best practice" currently captured by the existing reference and supporting documents?

Consideration:

The Version 0 drafting team stayed within the original scope of the SAR, as it believed it should have. Several proposed standards were dropped (notably some of the Phase III/IV planning standards, but the drafting team believes that it remained within the scope, i.e. did not expand the scope.

The implementation plan for Version 0 was posted with the ballot and is being approved with the ballot of the standards. More detailed plans will be provided by the NERC and Regional Reliability Organization compliance programs.

With the exception of the operating policies and planning standards, which are being retired, the documents in the operating manual and elsewhere will be retained and repackaged. The Operating and Planning Committees have been requested to review what updates to these documents would be required.

FirstEnergy – Raymond Morella

FirstEnergy would like to ensure that the 'Index of Waivers' list that is part of the Version '0' documentation be modified to include the 'RTO Inadvertent Interchange Accounting Waiver'. This waiver is correctly referred to in standard '006-BAL-006-0, but was excluded in the published index of waivers.

Consideration:

The drafting team did not intend to omit any existing waiver that is still applicable after the translation of the Version 0 standards. The referenced waiver will be added to the index of waivers as requested. Additionally, the drafting team will update the index to show the final disposition of all existing waivers.

FirstEnergy Solutions – Edward C. Stein

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Grant County PUD No.2 – Kevin John Conway

The original wording from Policy 3A.2.1 should be re-inserted into Version 0 Standard INT-001, Requirement 2.2. The current wording has proven divisive among several entities in the WECC. The change listed on the errata sheet is significant enough that another posting of the Version 0 Standards should have gone out for comment prior to posting for ballot. We have a further concern that even though the Reliability Authority has been removed from the Version 0 Standards for this posting, there should have been further comment from the industry solicited prior to balloting.

Consideration:

The drafting team modified INT-001 Requirement 2.2 in the errata sheet because the Interchange Subcommittee commented on a conflict introduced by lumping into the same requirement emergency transactions to address SOL and IROL limit violations and transactions used to replace a loss of generation. Emergency transactions to address SOL or IROL limit violations have different tagging requirements that are addressed in INT-004 Requirement 1.

In making this correction, the drafting team had to make an interpretation regarding what the intended requirement was for tagging emergency transactions to replace a generation loss. The drafting team consulted with the Interchange Subcommittee to determine the original intent of the Policy 3 language. On that basis, the drafting team proposed the following requirement in the errata sheet for INT-001 Requirement 2.2:

If the duration of the Emergency Transaction to replace the generation loss is less than 60 minutes, then the Transaction shall be exempt from tagging.

This compares to Operating Policy 3A 2.1, which states:

INTERCHANGE TRANSACTIONS established to replace unexpected generation loss, such as through prearranged reserve sharing agreements or other arrangements, are exempt from tagging for 60 minutes from the time at which the INTERCHANGE TRANSACTION begins.

One difference between the policy and the proposed standard is whether the exemption should apply if the transaction is ‘less than 60 minutes’ in duration, rather than ‘60 minutes or less’. This seemingly small difference is significant if a common practice is to schedule the replacement transaction for 60 minutes. There are other ambiguities regarding what emergency transactions have to be tagged and when.

Recognizing there is not a single agreed upon interpretation of the existing policy and no opportunity at this point to vet alternative views in the Version 0 standards, the drafting team is leaving the requirement as currently stated in the errata sheet. The drafting team recommend that the Interchange Subcommittee immediately prepare a SAR to propose revisions to address the remaining ambiguities before, or as soon as possible after, the implementation of the Version 0 standards.

The drafting team received comments on the first draft expressing concerns with the relationship between the Reliability Coordinator and Reliability Authority and determined a best approach for reaching consensus on the Version 0 standards was to remove the Reliability Authority. When asked a direct question during the posting of the second draft, the industry strongly supported that decision. There was significant opportunity for industry input on the proposal to remove the Reliability Authority from the Version 0 standards and, in fact, it was one of the most thoroughly discussed issues in the process.

Grant County PUD No.2 – Greg B. Lange

We believe that schedule seems to be more important that getting the correct product. One that will truly assist in creating a more reliable electric system.

Specifically we think the original wording for Policy 3A.2.1 should be reinserted into Version 0 Standard INT-001, Requirement 2.2. The current wording has created problems among and between WECC members. The change posted on the errata sheet was significant enough to warrant another posting of the Version 0 Standards, with time for comment and a new ballot to follow. Even though the Reliability Authority (RA) has been removed from this posting, further comment from the industry should have been solicited before balloting takes place.

Consideration:

The drafting team modified INT-001 Requirement 2.2 in the errata sheet because the Interchange Subcommittee commented on a conflict introduced by lumping into the same requirement emergency transactions to address SOL and IROL limit violations and transactions used to replace a loss of generation. Emergency transactions to address SOL or IROL limit violations have different tagging requirements that are addressed in INT-004 Requirement 1.

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Hydro-Quebec HQT – Michel Armstrong

Before the implementation date of april 2005 consideration should be given to resolve the following issues:

1. There remains vagueness in the application of Interconnection Reliability Operating Limits (IROL) and guidelines for how it is calculated
2. There is also some concern about the lack of well-defined compliance metrics for some of the operating related standards as well as the absence of levels of non-compliance. It is not clear how the compliance assessment process will work during evaluations of compliance with these particular standards

3. Also, it should be reiterated that non-monetary sanctions and levels of non compliance with associated letters/notifications of increasing severity are a more effective means of achieving compliance.

Consideration:

1. The issue of clarifying the requirements for calculating IROL was known prior to the start of the Version 0 standards development. A task force has been working on the issue and is expected to propose improvements to the standards. However, the Version 0 drafting team, charged with translating the existing standards, could not undertake to propose such improvements. The issue is particularly complex and requires more extensive industry input than was possible in the expedited time frame of the Version 0 standards.
2. The drafting team was assigned to translate the existing policies, standards, and compliance templates without adding new measures where they did not exist. The drafting team agrees that new measures and compliance information must be developed on a priority basis through a stakeholder process.
3. The definition of penalties and sanctions was outside the scope of the Version 0 standards, since there is no current provision for their implementation.

Idaho Power Company IPCO – Ronald Schellberg -

1. Errata changed the interpretation of the Operating Policies.
2. I am unable to find any evidence that many Planning Standards have been through a compliance review of any kind to know if whether these standards are appropriate as written:
   FAC-005, MOD-1 to 13, MOD-16 to 21, PRC-2 to 6, PRC-9, PRC-12 to 14, PRC-16 to 17, TPL-5 to 6 (Orange=RROs, Green=TO/TPs)
   Based upon the information available to me, these standards are no further along than the Phase 3&4 standards, these should receive the same status as the Phase 3 and 4 standards. It is inappropriate to exclude some but not others.
3. Explain why Standards I.A.M5, I.F.M6, II.D.M5, II.D.M7-9, III.A.M1-2, III.D.M5, III.E.M6, IV.A.M5, IV.B.M5 (Tan) where not addressed in the translation. Very difficult from NERC postings to determine that these are no longer standards.
4. I suggest that the vote be reballotted in logical sections.

Consideration:

1. Without more specific information, the drafting team cannot respond to your comment that the errata sheet changed the intent of operating policies.
2. The NERC web site does provide information on the compliance field testing that was done on the planning standards you've cited. Here is a link to the Annual Compliance Reports that contain the list of compliance templates field tested/used in each year's Compliance Enforcement Program: http://www.nerc.com/~comply/annual.html.

   The following table shows when each of these standards was entered into the Compliance Program:

Version 0 No.	Planning Standard No.	When Field Tested:	Last Approval Date
FAC-005	II.C. M2	1999	6/12/01
MOD-001	IE.1. M1	Last half 2000	2/20/02
MOD-002	IE.1. M3	Last half 2000	2/20/02

MOD-003	IE.1. M4	Last half 2000	2/20/02
MOD-004	IE.2. M1	Last half 2000	2/20/02
MOD-005	IE.2. M3	Last half 2000	2/20/02
MOD-006	IE.2. M4	Last half 2000	2/20/02
MOD-007	IE.2. M5	Last half 2000	2/20/02
MOD-008	IE.2. M6	Last half 2000	2/20/02
MOD-009	IE.2. M8	Last half 2000	2/20/02
MOD-010	II.A. M1 *	1999	6/12/01
MOD-011	II.A. M2 *	1999	6/12/01
MOD-012	II.A. M3 *	1999	6/12/01
MOD-013	II.A. M4 *	1999	6/12/01
MOD-016	II.D. M1	1999	6/12/01
MOD-017	II.D. M4	1999	6/12/01
MOD-018	II.D. M6	2000	10/16/01
MOD-019	II.D. M10	1999	6/12/01
MOD-020	II.D. M11	2000	10/16/01
MOD-021	II.D. M12	2000	10/16/01
PRC-002	IF. M1	1999	4/2/04
PRC-003	III.A. M3	2000	2/20/02
PRC-004	III.A. M4	2000	4/2/04
PRC-005	III.A. M5 **	2002	2/20/02
PRC-006	III.D. M1	2000	4/2/04
PRC-009	III.D. M4 ***	2000	10/16/01
PRC-012	III.F. M1	2000	10/16/01
PRC-013	III.F. M2	2000	10/16/01
PRC-014	III.F. M3	2000	10/16/01
PRC-016	III.F. M5	2000	10/16/01
PRC-017	III.F. M6	2000	4/2/04
TPL-005	IB. M1 ****	1999	4/2/04
TPL-006	IB. M2 ****	1999	6/12/01

* The original II.A.M1 was eliminated and II.A.M2 - 5 were revised and renumbered II.A.M1 - 4

** Originally part of III.A.M3

*** Originally III.D.M6

**** Originally I.B.M3 and M4

3. Planning Standards I.A.M5, I.F.M6, II.D.M5, II.D.M7-9, III.A.M1, III.D.M5, III.E.M6, IV.A.M5, IV.B.M5 were either eliminated and/or merged into other measurements, or simply renumbered prior to their consideration for inclusion in Version 0. Measurement III.A.M2 is now part of the "Phase III/IV Planning Standards - Protection and Control" SAR.

4. The transition plan included in the SAR indicated the Version 0 standards would be voted as a single block and industry comments supported this concept. The Standards Authorization Committee and the NERC Board approved the transition plan with that assumption. The strategic value of approving the entire set of standards as a block outweighed the need for a vote on individual standards, since Version 0 was a translation

of existing requirements and improvements to individual standards were to be deferred to future versions of the standards.

IMO – Don Tench

With regards to the Version 0 Reliability Standards posted for balloting (Dec 3-13, 2004), the Independent Electricity Market Operator (the IMO "Segment #2") submits a vote of "Affirmative (Yes)" on the proposed standards. In order to facilitate the NERC SDT, the IMO is submitting the following comments as outlined below:

Comments on Draft 3 of Version 0 Operating Standards

1. There is a concern about the e-tagging compliance measures/levels in INT-001-0 (Interchange Transaction Tagging). It needs to be noted that the associated original template P3T3 included non-compliance levels i.e. L1 and L4. These levels of non-compliance from original template P3T3 have not been mapped/translated into this standard INT-001-0. However, if mapped, we were concerned that not meeting the measure 100 % of the time would result in a L4 non-compliance level. This seemed overly severe. Nevertheless, it will be appropriate to include reasonable/practical levels of non-compliance.

   IMO's Proposed Recommendation: We recommend that the levels of non-compliance for this standard-INT-001-0 should be assessed/reviewed for their inclusion in the near future, and if prescribed should be reasonable and of practical nature.

2. Many of the draft 3 Version 0 standards do not have measures nor levels of non-compliance as they never existed previously.

   IMO's Proposed Recommendation: For the purposes of effective implementation/enforcement of these standards, we recommend that NERC should specify the associated measures and non-compliance levels to these operating standards in the near future (one option is that initially a priority in prescribing the measures may be given to those standards that are of more significance).

Comments on Draft 3 of Version 0 Planning Standards

3. The wording of the original standard statements has not been mapped exactly in some cases into the version 0 standards. For example the original planning standards included the word "design" which is not incorporated in all Version 0 Planning Standard

   IMO's Proposed Recommendation: We request the wording, as it exists in the Planning Standards, be directly translated into the Version 0 standards.

Consideration:

1. The drafting team determined in researching the tagging levels of non-compliance that the compliance program has previously recognized a problem with the levels of non-compliance, notably that missing one tag was a level 4 violation, and has not included this measure in the compliance reporting. Therefore, the drafting team did not include these levels of non-compliance in Version 0. The drafting team recommends this compliance information be completed as soon as possible through a stakeholder due process.
2. The drafting team was assigned to translate the existing policies, standards, and compliance templates without adding new measures where they did not exist. The drafting team agrees that new measures and compliance information must be developed on a priority basis through a stakeholder process.
3. The SDT developed a table to show how the 'S' statements from the Planning Standards were considered in developing the associated Version 0 Standards. There were several cases, as you've indicated, where the language in one of the 'S' statements implied a level of performance that was not supported by associated requirements or measures. In each case where a conflict existed between the implied performance standard as stated in the 'S'

statement, and the performance specified in the requirements and measures, the SDT defaulted to using language from requirements and measures.

Indianapolis Power & Light Company – Michael Lee Holtsclaw

Indianapolis Power & Light supports the development of the Version 0 Reliability Standards

Consideration:

The SDT appreciates your support of Version 0.

JEA – William Garry Baker

JEA supports Version 0 Reliability Standards.

Consideration:

The SDT appreciates your support of Version 0.

JEA – Ted E. Hobson

JEA is in favor of the proposed reliability standard.

Consideration:

The SDT appreciates your support of Version 0.

LIPA – Richard Bolbrock

1. There is vagueness in the application of IROL limits -- keep as is but revise in future standard revisions.
2. There should be a statement that entities may have more stringent standards than Version O.
3. There should be non-monetary sanctions, such as letters, for non-compliance.

Consideration:

1. The drafting team agrees.
2. NERC does not preclude any entity from developing standards that are more stringent than NERC's Reliability Standards. The NERC Reliability Standards Process Manual includes the following language, which clarifies that Regions may develop standards that are more stringent than NERC Reliability Standards: "Regions may develop, through their own processes, separate Regional Standards that go beyond, add detail to, or implement NERC Organization Standards, or that cover matters not addressed in NERC Organization Standards."
3. The definition of penalties and sanctions was outside the scope of the Version 0 standards, since there is no current provision for their implementation.

MidAmerican Energy Company – Thomas C. Mielnik

MidAmerican Energy supports adoption of the standards as being important for the reliability of the interconnected network. We have provided comments on the planning standards which were not incorporated into the standard because the Version 0 drafting team thought that they involved changes which were outside of their scope. We believe that the standards continue to have non-deal-killer issues, such as inconsistency of compliance levels, ambiguity with regard to prior planned outages for Category C events in TPL-003-0, need to pull certain business practices from MOD-001-0 through MOD-009-0, and the need to refer to confidentiality for Standards of

Conduct or Critical Energy Infrastructure Information purposes in MOD-010-0, MOD-012-0, MOD-018-0 through MOD-020-0.

Consideration:

The SDT agrees that there are many opportunities for improving Version 0 standards to further improve consistency and clarity. All suggested changes to Version 0 identified as 'suggestions for improvements' have been tabulated and will be distributed to associated Version 1 drafting teams for consideration as either revisions to Version 0 or in the development of associated Version 1 standards.

National Grid USA Transmission – Peter Henry Lebro

Accountabilities would have been much clearer (without the need for delegation) if truly RC functions currently listed under TOP were included under the RC requirements, with truly TOP functions remaining separate.

Consideration:

The drafting agrees there could have been further improvements to the organization of the standards, but chose to strike a balance by not making so many improvements that the standards were no longer recognizable as a translation of the existing policies. Further improvements should be accommodated in future versions of the standards.

New Brunswick Power Corporation – Wayne Snowdon

I am voting in support of Version 0 Reliability Standards because the following concerns that were expressed by NPCC have been addressed to my satisfaction:

1. Previous drafts of the standards set included the Reliability Authority (RA) designation from the Functional Model (FM). The NERC FM is presently scheduled to be reviewed and revised based on industry concerns.
2. Previous drafts of the Glossary of Terms associated with the Version 0 Standards contained a definition of Bulk Electric System that was inconsistent with our performance based definition in NPCC. NPCC promoted the concept of allowing the Region to determine what constituted its Bulk System and the definition now allows us to do this. NPCC believes this issue has been satisfactorily addressed in the Version 0 Standards.
3. Previous drafts of the standards set also included "translations" of the NERC Phase III and IV Planning Standards. NPCC believed and strongly suggested that these Standards not be included in the Version 0 Standards as they had not gone through the full field test/comment/revision cycle and also that they would not be fully "implementable" as mandated by the NERC Board on April 1, 2005 when they are scheduled to go into effect. In response to these concerns raised by NPCC and others, these standards are now removed from the standards set and will be developed through the normal NERC ANSI approved Reliability Standards Process. NPCC believes this issue to be satisfactorily addressed in the Version 0 Standards.

Consideration:

The SDT appreciates your support of Version 0.

Niagara Mohawk – Michael Schiavone

1. Although the drafting team attempted to include the "S" or Standard language statements in the Requirements section, NPCC still believes some deficiency may exist and requests

the language, as it exists in the Planning Standards, be directly brought into the Version 0 standards.

2. There remains vagueness in the application of Interconnection Reliability Operating Limits (IROL) and guidelines for how it is calculated. The RC has been designated as being responsible for maintaining the interconnection within IROLs, however debate on how these should be calculated continues.

3. There is also some concern about the lack of well-defined compliance metrics for some of the operating related standards as well as the absence of levels of non-compliance. It is not clear how the compliance assessment process will work during evaluations of compliance with these particular standards. During the Version 0 web cast, it was indicated that the compliance program for the Version 0 set would initially remain unchanged from this year's program, "initially" until additional measures could be added. This is a satisfactory step and is supported. As the compliance programs expands beyond the scope of this year's program it was stated that additional program compliance metrics/measures and levels will go through the NERC Reliability Standards Process.

4. Also, it should be reiterated that non-monetary sanctions and levels of non compliance with associated letters/notifications of increasing severity are a more effective means of achieving compliance.

Consideration:

1. The drafting team developed a table to show how the 'S' statements from the Planning Standards were considered in developing the associated Version 0 Standards. There were several cases where the language in one of the 'S' statements implied a level of performance that was not supported by its associated requirements or measures. In each case where a conflict existed between the implied performance standard as stated in the 'S' statement, and the performance specified in the requirements and measures, the drafting team defaulted to using language from requirements and measures.

2. The issue of clarifying the requirements for calculating IROL was known prior to the start of the Version 0 standards development. A task force has been working on the issue and is expected to propose improvements to the standards. However, the Version 0 drafting team, charged with translating the existing standards, could not undertake to propose such improvements. The issue is particularly complex and requires more extensive industry input than was possible in the expedited time frame of the Version 0 standards.

3. The drafting team was assigned to translate the existing policies, standards, and compliance templates without adding new measures where they did not exist. The drafting team agrees that new measures and compliance information must be developed on a priority basis through a stakeholder process.

4. The definition of penalties and sanctions was outside the scope of the Version 0 standards, since there is no current provision for their implementation.

NPPD – Alan Boesch

1. There is a big difference between a compliance program that has measurements and one that does not have measurements. All the templates in previous compliance programs had measurements. As proposed 22 of the 40 operating standards have no measurements. As stated in the NERC Reliability Standards Process Manual "measurements are used to assess performance and outcomes for the purpose of determining compliance with the requirements. Measurements are proxies to assess required performance or outcomes, achieving the full

compliance level of each measurement should be a necessary and sufficient indicator that the requirement was met.” Without measurements what will be the indicator that the requirement was met? NPPD expects that any requirement without a measurement will not be included in the compliance program.

2. EOP-003-0 R2. says "Each Transmission Operator and Balancing Authority shall establish plans for automatic load shedding for underfrequency or undervoltage conditions."

This seems to imply that each TOP has load shedding for undervoltage, this is not a common practice or a requirement. The planning standards have a requirement for Regions to establish a underfrequency load shedding program. There is not a similar requirement for undervoltage load shedding program. If there is a study that supports installing undervoltage load shedding then it should be installed and measured. To be consistent with Policy 6 the requirement should be changed to say:

“Each Transmission Operator and Balancing Authority shall establish plans for automatic load shedding."

Consideration:

The drafting team was assigned to translate the existing policies, standards, and compliance templates without adding new measures where they did not exist. The drafting team agrees that new measures and compliance information must be developed on a priority basis through a stakeholder process.

The drafting team was careful not to specify under-voltage load shedding as being specifically required, since that is not in current policy. However, current Policy 6 Requirement 1.2 requires that “*automatic load shedding shall be initiated at the time the system frequency or voltage has declined to an agreed-to level. Automatic load shedding shall be in steps related to one or more of the following: frequency, rate of frequency decay, voltage level, rate of voltage decay or power flow levels.*” The drafting team has drafted the requirement to state that automatic load shedding is required and the <u>conditions</u> which are to be considered as triggering the need for shedding load, but not what type of load shedding equipment is appropriate.

NPPD – Jon Sunneberg

1. There is a big difference between a compliance program that has measurements and one that does not have measurements. All the templates in previous compliance programs had measurements. As proposed 22 of the 40 operating standards have no measurements. As stated in the NERC Reliability Standards Process Manual “measurements are used to assess performance and outcomes for the purpose of determining compliance with the requirements. Measurements are proxies to assess required performance or outcomes, achieving the full compliance level of each measurement should be a necessary and sufficient indicator that the requirement was met.” Without measurements what will be the indicator that the requirement was met? NPPD expects that any requirement without a measurement will not be included in the compliance program.

2. EOP-003-0 R2. says "Each Transmission Operator and Balancing Authority shall establish plans for automatic load shedding for underfrequency or undervoltage conditions."

This seems to imply that each TOP has load shedding for undervoltage, this is not a common practice or a requirement. The planning standards have a requirement for Regions to establish a underfrequency load shedding program. There is not a similar requirement for undervoltage load shedding program. If there is a study that supports installing undervoltage load shedding then it should be installed and measured. To be consistent with Policy 6 the requirement should be changed to say:

"Each Transmission Operator and Balancing Authority shall establish plans for automatic load shedding."

Consideration:

The drafting team was assigned to translate the existing policies, standards, and compliance templates without adding new measures where they did not exist. The drafting team agrees that new measures and compliance information must be developed on a priority basis through a stakeholder process.

The drafting team was careful not to specify under-voltage load shedding as being specifically required, since that is not in current policy. However, current Policy 6 Requirement 1.2 requires that "automatic load shedding shall be initiated at the time the system frequency or voltage has declined to an agreed-to level. Automatic load shedding shall be in steps related to one or more of the following: frequency, rate of frequency decay, voltage level, rate of voltage decay or power flow levels." The drafting team has drafted the requirement to state that automatic load shedding is required and the <u>conditions</u> which are to be considered as triggering the need for shedding load, but not what type of load shedding equipment is appropriate.

NYPA – Ralph Rufrano

There is some concern that the translation for Standard I.A.M2 does not include the provision that " ...transmission systems also shall be capable of accommodating planned bulk electric equipment outages and continuing to operate within thermal, voltage and stability limits under the contingency conditions as defined in Category B of Table I..." Unless moved elsewhere in the standard this is an omission from the present policy.

Consideration:

Standard TPL-002-0 does require that the Planning Authority and Transmission Planner have a current or past study and/or system simulation testing that addresses a list of categories, showing system performance under Category B of Table 1 (single contingencies).The following is one of those categories:

> R.1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

NYSRC – Alan Adamson

The NYSRC believes that the "show stoppers" included in its comments on Drafts #1 & 2 of the Version 0 Standards were adequately addressed in Draft #3, and therefore has voted in the affirmative to approve this draft. We do, however, wish to offer the following comments:

1. There remains vagueness in the application of Interconnection Reliability Operating Limits (IROL) and guidelines for how it is calculated. Therefore, debate continues on how IROL should be calculated. We urge that future revisions of Version 0 will address this issue.
2. Our comments on earlier drafts indicated concern that the "S" or Standard language statements in the existing standards were not fully translated into Version 0. Although the drafting team did address this concern to a large extent, we note that this deficiency still remains in parts of this draft. Although we elected to vote in favor of accepting Draft #3,

we would have preferred that the language in the existing standards had been fully translated.

3. In previous comments we urged NERC to state in Version 0 that Regions may implement more stringent standards than stated in these standards. This suggestion has not yet been implemented. We continue to urge its inclusion.
4. The NYSRC continues to urge NERC to adopt non-monetary sanctions in the form of letter notifications for instances of non-compliance.

Consideration:

1. The issue of clarifying the requirements for calculating IROL was known prior to the start of the Version 0 standards development. A task force has been working on the issue and is expected to propose improvements to the standards. However, the Version 0 drafting team, charged with translating the existing standards, could not undertake to propose such improvements. The issue is particularly complex and requires more extensive industry input than was possible in the expedited time frame of the Version 0 standards.
2. The SDT developed a table to show how the 'S' statements from the Planning Standards were considered in developing the associated Version 0 Standards. There were several cases where the language in one of the 'S' statements implied a level of performance that was not supported by its associated requirements or measures. In each case where a conflict existed between the implied performance standard as stated in the 'S' statement, and the performance specified in the requirements and measures, the SDT defaulted to using language from requirements and measures.
3. NERC does not preclude any entity from developing standards that are more stringent than NERC's Reliability Standards. The NERC Reliability Standards Process Manual includes the following language, which clarifies that Regions may develop standards that are more stringent than NERC Reliability Standards:

   "Regions may develop, through their own processes, separate Regional Standards that go beyond, add detail to, or implement NERC Organization Standards, or that cover matters not addressed in NERC Organization Standards."
4. The definition of penalties and sanctions was outside the scope of the Version 0 standards, since there is no current provision for their implementation.

Progress Energy – Wayne Lewis

Progress Energy expressed in comments to the North American Electric Reliability Council (NERC) on Draft 2 of the proposed Version 0 Reliability Standards our concern that neither the functional model nor the proposed Version 0 standards should be allowed to impede the ability of utilities to fulfill their electric service obligations under state law. We further expressed our concern that the proposed Version 0 standards and the planned functional entity registration not be used by NERC to dictate a particular industry structure or to limit who may register as functional entities. We expressed to you that in many areas of the country, including the Southeast, the responsibility, authority, control and liability for the operation of the electric system as a whole is granted by the states to the utilities as a part of their utility franchise. While the utility may contract for certain tasks to be performed by another entity, such as a Reliability Coordinator, it may not delegate final authority, control, responsibility or liability to another entity without the prior approval of the state.

With the above in mind, Progress Energy's vote is cast in reliance upon the representations made by the North American Electric Reliability Council ("NERC") in a letter dated November 5, 2004 to all Regional Managers that "Registration should not be seen as prescribing organizational structures, responsibilities, or relationships. The registration is simply recording which organizations are responsible for meeting the Version 0 reliability standards and ensuring that all reliability requirements are addressed in each area of an Interconnection." Consistent with this commitment by NERC it is understood that NERC will place no restrictions or limitations on the registration of entities to perform functions in accordance with these standards.

Further, this vote is made in reliance upon the NERC's Post-Conference Comments filed with the Federal Energy Regulatory Commission in Docket No. PL04-13-000. In particular, the comments contained in Section 6 entitled "Correction of Inaccuracies Regarding Requirements for Load Shedding and Operating Tools.", which bring additional clarity to the responsibilities and authorities of the Reliability Coordinators and the operating entities (control areas and transmission operators). In particular, the comments contained in Section 6 entitled "Correction of Inaccuracies Regarding Requirements for Load Shedding and Operational Tools" state "that Operating Policy 9 (which is the genesis of Version 0) does not contain an absolute imperative that control areas blindly follow directives from a reliability coordinator".

Consideration:

The Version 0 Reliability Standards adopt the identical requirements that Reliability Coordinators have today in the current NERC Operating Policy 9. The Version 0 Reliability Standards, and the associated request to register organizations as responsible entities, do not prescribe any particular organizational structure, authorities, responsibilities, or relationships. The standards simply define the minimum requirements for the reliable planning and operation of bulk electric systems. These requirements are neutral with respect to organizational structures that are necessary or appropriate to meet the reliability requirements. Furthermore, Standard IRO-001 Requirement 8 specifically exempts an entity from following a directive of a Reliability Coordinator if such an action would "*violate safety, equipment, or regulatory or statutory requirements.*"

Public Works Commission Fayetteville – Samuel T. Stryker

My thanks to all the people who worked long and hard to move us to this point on Version 0.

Consideration:

The SDT appreciates your support of Version 0.

Puget Sound Energy Transmission – Dave M Magnuson

Puget Sound Energy supports the Version 0 goal of creating measurable and unambiguous reliability standards without significant wholesale changes to tools or practices.

While the last minute clarification of Policy 3 tagging requirements for emergency schedules should have been addressed much sooner in the process, Puget Sound Energy supports the clarification as it eliminates ambiguity in the current Policy without causing a change to practices or tools.

Consideration:

The SDT appreciates your support of Version 0.

Sacramento Municipal Utility District – Robert D. Schwermann

Errata change, Version 0 Standard INT-001, Requirement 2.2, is a substantial change to the requirements of the original operating policies. The NERC IS has agreed to review this requirement and we support the efforts of the IS to clear up this issue of tagging inside a 60 minute time frame. It is also understood that this change should be completed by April 05.

Consideration:

The drafting team modified INT-001 Requirement 2.2 in the errata sheet because the Interchange Subcommittee commented on a conflict introduced by lumping into the same requirement emergency transactions to address SOL and IROL limit violations and transactions used to replace a loss of generation. Emergency transactions to address SOL or IROL limit violations have different tagging requirements that are addressed in INT-004 Requirement 1.

In making this correction, the drafting team had to make an interpretation regarding what the intended requirement was for tagging emergency transactions to replace a generation loss. The drafting team consulted with the Interchange Subcommittee to determine the original intent of the Policy 3 language. On that basis, the drafting team proposed the following requirement in the errata sheet for INT-001 Requirement 2.2:

If the duration of the Emergency Transaction to replace the generation loss is less than 60 minutes, then the Transaction shall be exempt from tagging.

This compares to Operating Policy 3A 2.1, which states:

INTERCHANGE TRANSACTIONS established to replace unexpected generation loss, such as through prearranged reserve sharing agreements or other arrangements, are exempt from tagging for 60 minutes from the time at which the INTERCHANGE TRANSACTION begins.

One difference between the policy and the proposed standard is whether the exemption should apply if the transaction is 'less than 60 minutes' in duration, rather than '60 minutes or less'. This seemingly small difference is significant if a common practice is to schedule the replacement transaction for 60 minutes. There are other ambiguities regarding what emergency transactions have to be tagged and when.

Recognizing there is not a single agreed upon interpretation of the existing policy and no opportunity at this point to vet alternative views in the Version 0 standards, the drafting team is leaving the requirement as currently stated in the errata sheet. The drafting team recommend that the Interchange Subcommittee immediately prepare a SAR to propose revisions to address the remaining ambiguities before, or as soon as possible after, the implementation of the Version 0 standards.

Sacramento Municipal Utility District – E. Nick Henery

Errata change, Version 0 Standard INT-001, Requirement 2.2, is a substantial change to the requirements of the original operating policies. The Errata change appears to be a last minute change to the standards development and should not be used in Version 0. The only change from the Policy 3 language is the language that was presented to the industry in Drafts 1 and 2.

Consideration:

The drafting team modified INT-001 Requirement 2.2 in the errata sheet because the Interchange Subcommittee commented on a conflict introduced by lumping into the same requirement emergency transactions to address SOL and IROL limit violations and transactions used to replace a loss of generation. Emergency transactions to address SOL or IROL limit violations have different tagging requirements that are addressed in INT-004 Requirement 1.

In making this correction, the drafting team had to make an interpretation regarding what the intended requirement was for tagging emergency transactions to replace a generation loss. The drafting team consulted with the Interchange Subcommittee to determine the original intent of the Policy 3 language. On that basis, the drafting team proposed the following requirement in the errata sheet for INT-001 Requirement 2.2:

If the duration of the Emergency Transaction to replace the generation loss is less than 60 minutes, then the Transaction shall be exempt from tagging.

This compares to Operating Policy 3A 2.1, which states:

INTERCHANGE TRANSACTIONS established to replace unexpected generation loss, such as through prearranged reserve sharing agreements or other arrangements, are exempt from tagging for 60 minutes from the time at which the INTERCHANGE TRANSACTION begins.

One difference between the policy and the proposed standard is whether the exemption should apply if the transaction is 'less than 60 minutes' in duration, rather than '60 minutes or less'. This seemingly small difference is significant if a common practice is to schedule the replacement transaction for 60 minutes. There are other ambiguities regarding what emergency transactions have to be tagged and when.

Recognizing there is not a single agreed upon interpretation of the existing policy and no opportunity at this point to vet alternative views in the Version 0 standards, the drafting team is leaving the requirement as currently stated in the errata sheet. The drafting team recommend that the Interchange Subcommittee immediately prepare a SAR to propose revisions to address the remaining ambiguities before, or as soon as possible after, the implementation of the Version 0 standards.

Salt River Project – Robert Kondziolka

The original wording from Policy 3A 2.1 should be used in version 0 Standard INT-001, Requirement 2.2. Changes or clarifications via the errata sheet can be more properly addressed through the submittal of a SAR using the Version 1 process to provide adequate industry input regarding the interpretations of the requirements.

Consideration:

The drafting team modified INT-001 Requirement 2.2 in the errata sheet because the Interchange Subcommittee commented on a conflict introduced by lumping into the same requirement emergency transactions to address SOL and IROL limit violations and transactions used to replace a loss of generation. Emergency transactions to address SOL or IROL limit violations have different tagging requirements that are addressed in INT-004 Requirement 1.

In making this correction, the drafting team had to make an interpretation regarding what the intended requirement was for tagging emergency transactions to replace a generation loss. The drafting team consulted with the Interchange Subcommittee to determine the original intent of the Policy 3 language. On that basis, the drafting team proposed the following requirement in the errata sheet for INT-001 Requirement 2.2:

If the duration of the Emergency Transaction to replace the generation loss is less than 60 minutes, then the Transaction shall be exempt from tagging.

This compares to Operating Policy 3A 2.1, which states:

INTERCHANGE TRANSACTIONS established to replace unexpected generation loss, such as through prearranged reserve sharing agreements or other arrangements, are exempt from tagging for 60 minutes from the time at which the INTERCHANGE TRANSACTION begins.

One difference between the policy and the proposed standard is whether the exemption should apply if the transaction is 'less than 60 minutes' in duration, rather than '60 minutes or less'. This seemingly small difference is significant if a common practice is to schedule the replacement transaction for 60 minutes. There are other ambiguities regarding what emergency transactions have to be tagged and when.

Recognizing there is not a single agreed upon interpretation of the existing policy and no opportunity at this point to vet alternative views in the Version 0 standards, the drafting team is leaving the requirement as currently stated in the errata sheet. The drafting team recommend that the Interchange Subcommittee immediately prepare a SAR to propose revisions to address the remaining ambiguities before, or as soon as possible after, the implementation of the Version 0 standards.

Santee Cooper – Terry Blackwell

While Santee Cooper has voted yes to approve the Version 0 Standards, we recognize there are still outstanding jurisdictional issues which should be resolved through further development of the Functional Model and registration of entities under the Functional Model.

Consideration:

The drafting team appreciates your support of Version 0 and your willingness to separate its approval from further refinement of the Functional Model.

Santee Cooper – Zack Dusenbury

While Santee Cooper has voted yes to approve the Version 0 Standards, we recognize there are still outstanding jurisdictional issues which should be resolved through further development of the Functional Model and registration of entities under the Functional Model.

Consideration:

The drafting team appreciates your support of Version 0 and your willingness to separate its approval from further refinement of the Functional Model.

Santee Cooper – Suzanne Ritter

While Santee Cooper has voted yes to approve the Version 0 Standards, we recognize there are still outstanding jurisdictional issues which should be resolved through further development of the Functional Model and registration of entities under the Functional Model.

Consideration:

The drafting team appreciates your support of Version 0 and your willingness to separate its approval from further refinement of the Functional Model.

Sierra Pacific Power Company – Gene Henneberg

Sierra Pacific is satisfied with the large majority of the Version 0 Standards. However, we have significant concerns with two sections in the Operating and Planning Standards.

1. Operating Standards
   Section INT-001 This standard seems to be ambiguous about the time frame when generation must be scheduled.
2. Planning Standards
   MOD-006-0 The Capacity Benefit Margin (CBM) unduly restricts scheduling ability to the detriment of reliability. The transmission owner should be free to choose the order in which to use reserve components. In addition, it seems more appropriate that the discussion of CBM should be in the Operating Standards.

Consideration:

The drafting team assumes this first comment refers to the exemption for tagging transactions following a generation loss. The drafting team modified INT-001 Requirement 2.2 in the errata sheet because the Interchange Subcommittee commented on a conflict introduced by lumping into the same requirement emergency transactions to address SOL and IROL limit violations and transactions used to replace a loss of generation. Emergency transactions to address SOL or IROL limit violations have different tagging requirements that are addressed in INT-004 Requirement 1.

In making this correction, the drafting team had to make an interpretation regarding what the intended requirement was for tagging emergency transactions to replace a generation loss. The drafting team consulted with the Interchange Subcommittee to determine the original intent of the Policy 3 language. On that basis, the drafting team proposed the following requirement in the errata sheet for INT-001 Requirement 2.2:

If the duration of the Emergency Transaction to replace the generation loss is less than 60 minutes, then the Transaction shall be exempt from tagging.

This compares to Operating Policy 3A 2.1, which states:

INTERCHANGE TRANSACTIONS established to replace unexpected generation loss, such as through prearranged reserve sharing agreements or other arrangements, are exempt from tagging for 60 minutes from the time at which the INTERCHANGE TRANSACTION begins.

One difference between the policy and the proposed standard is whether the exemption should apply if the transaction is ‘less than 60 minutes’ in duration, rather than ‘60 minutes or less’. This seemingly small difference is significant if a common practice is to schedule the replacement transaction for 60 minutes. There are other ambiguities regarding what emergency transactions have to be tagged and when.

Recognizing there is not a single agreed upon interpretation of the existing policy and no opportunity at this point to vet alternative views in the Version 0 standards, the drafting team is leaving the requirement as currently stated in the errata sheet. The drafting team recommend that the Interchange Subcommittee immediately prepare a SAR to propose revisions to address the remaining ambiguities before, or as soon as possible after, the implementation of the Version 0 standards.

The Version 0 SDT was charged with producing an ‘even’ translation of existing Operating Policies and Planning Standards. The change you are suggesting to MOD-006 would require the drafting team to change the original intent of the existing planning standard and this type of change is outside the scope of the approved SAR for Version 0.

Snohomish County PUD – John Martinsen

Snohomish agrees that planning and operating standards are necessary to provide for a secure and reliable electric system. What is more important however is that the participants see that it is in their own best interests to voluntarily participate in meeting or exceeding the standards in order to reduce exposure to outages. For participants to support the standards they must have an effective means of meeting system reliability criteria and also provide for a cost efficient implementation. Snohomish is concerned that the Version 0 effort is more a direct reaction from the political fallout of the August 14, 2003 Northeast blackout than it is an effective and cost efficient solution. In addition, threats from the Federal Energy Regulatory Commission ("FERC") to commandeer the electric industry standard process have been noted throughout the Version 0 effort.

This is contrary to the American National Standards Institute (“ANSI”) accredited NERC standard develop process. The new NERC process was touted and intended to be developed via a consensus-based approach and then voted on by the electric industry without the undue political pressure that seems to be present in this case. Snohomish acknowledges the efforts of NERC and the electric industry participants in their valiant effort to accelerate Version 0 through the standard development process in a heroic attempted to meet an unrealistic schedule mandated by FERC. However, the pressure by FERC on the electric industry to pass Version 0 or else pay the consequences has significantly diminished the intent of the ANSI accredited consensus-based process.

In the Western Interconnection, where for nearly a decade the existing WECC standards have been relatively well followed, the end use customers will have little to gain from the implementation of Version 0. The best and lowest cost solution may be the consistent application and implementation of the existing voluntary standards. We suggest that prior to implementing these new standards that NERC commission an independent entity to study and comment on the utilities' ability under the proposed standards to implement the most cost efficient solutions as a means of meeting reliability criteria and to compare the proposed standards to alternative solutions.

Issues that need to be resolved

1. Are new standards needed and is it necessary to rush the implementation? The old standards and policies were adequate, but they were not followed consistently.
2. Will new standards resolve blackout, if utilities are not required to meet the standards.
3. What is the cost of implementing the Version 0 standards and will they reduce the probability of blackouts?

Consideration:
The Version 0 Reliability Standards result from an industry initiative to improve its standards for the planning and operation of bulk electric systems. The standards are being developed as a step toward enabling the industry to have high quality, clear, and enforceable standards. Version 0 standards have resulted in marked improvements in clarifying the reliability requirements and who is responsible for meeting them. Version 0 also serves as a launching point for improvements to reliability standards through the open, ANSI-accredited process.

The August 14, 2003, blackout pointed out to NERC the need for improving the standards and for expediting standards development. The NERC Board charged NERC with improving its standards in a February 2004 set of blackout recommendations. The project is driven by and is for the benefit of the industry's /reliability stakeholders and their customers.

Because Version 0 is a translation of existing requirements, there are minimal cost impacts other than changing the standards and compliance documentation. Certainly no 'new solutions' for meeting reliability criteria have been proposed. The standards define minimum reliability criteria, not how the criteria are to be achieved.

The new standards are necessary for the reasons stated above and the expedited schedule was important to establish a launching point for other improvements and additions stemming from blackout recommendations. Responsible entities are required to meet the standards, as they are required today to meet NERC's operating policies and planning standards. The improved clarity of the requirements and accountabilities will help to resolve issues noted in the blackout investigation.

South Carolina Electric & Gas – Lee N Xanthakos

SCE&G's vote is based upon its concern regarding transfer of authority to a Reliability Coordinator. SCE&G's understanding of South Carolina law is that an electrical utility may not transfer or assign its powers or privileges without the approval of the Public Service Commission of South Carolina ("Commission") (see S.C. Code Ann. 58-27-1300 (2004)). To date, the South Carolina Commission has not approved assignment or transfer of power, privilege, or authority to operate the transmission system or any part thereof of SCE&G.

SCE&G's interpretation of Version 0 requires transfer and assignment of its powers to the Reliability Coordinator. SCE&G does not believe that it may agree to an assignment or transfer of power, privilege or authority to a Reliability Coordinator, therefore SCE&G is unable to vote yes.

Consideration:

The Version 0 Reliability Standards adopt the identical requirements that Reliability Coordinators have today in the current NERC Operating Policy 9. The Version 0 Reliability Standards, and the associated request to register organizations as responsible entities, do not prescribe any particular organizational structure, authorities, responsibilities, or relationships. The standards simply define the minimum requirements for the reliable planning and operation of bulk electric systems. These requirements are neutral with respect to organizational structures that are necessary or appropriate to meet the reliability requirements. Furthermore, Standard IRO-001 Requirement 8 specifically exempts an entity from following a directive of a Reliability Coordinator if such an action would "*violate safety, equipment, or regulatory or statutory requirements.*"

SCE&G – Hubert Young

SCE&G's vote is based upon its concern regarding transfer of authority to a Reliability Coordinator. SCE&G's understanding of South Carolina law is that an electrical utility may not transfer or assign its powers or privileges without the approval of the Public Service Commission of South Carolina ("Commission") (see S.C. Code Ann. 58-27-1300 (2004)). To date, the South Carolina Commission has not approved assignment or transfer of power, privilege, or authority to operate the transmission system or any part thereof of SCE&G.

SCE&G's interpretation of Version 0 requires transfer and assignment of its powers to the Reliability Coordinator. SCE&G does not believe that it may agree to an assignment or transfer of power, privilege or authority to a Reliability Coordinator, therefore SCE&G is unable to vote yes.

Consideration:

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South Mississippi Electric Power Association SME – Dan Kay

It seems as the conversion process to the version zero standards has resulted in some of the policies being changed and/or added. For the majority of these interpretations, I do not disagree. The main concern I have with total rewrite, is the implementation of the standards without the benefit of an acceptable training period for System Operators prior to the standards taking effect.

Consideration:

The vast majority of the Version 0 Reliability Standards present the same requirements as the existing operating policies and planning standards. With only a few limited exceptions, no changes in industry practices or procedures are necessary to implement the standards. The most significant change is the format and organization of the standards, which will require some training to familiarize operating personnel and support staff. There will be a period of a few months between the time that the standards are balloted by the industry (December, 2004) and the April 1, 2005, implementation date.

Robert Snow

The working group did a great job in going through many comments. There are two items that forced my negative vote.

1. The definition of Transmission Systems excludes the areas that many have stated must be improved. For example, buses at a remote generator or load are excluded from the standard. I have suggested that if the facilities are in a transmission tariff and have the attributes of at least some of the FERC seven factor tests, they are transmission. That would be independent of their voltage.
2. The standard does not require any action other than studies. Some interpreted the old standards s having at least some capability to get things constructed. With the functional model, that is essentially eliminated.

Consideration:

1. The drafting team has defined Bulk Electric System so as not to preclude the types of equipment listed by the commenter. The definition of Bulk Electric System allows that Regional Reliability Organizations may set additional criteria based on regional or local requirements.
2. Although the second comment does not identify a specific standard, the drafting team assumes the comment refers to the removal of the word, 'constructed' from the planning standards. The drafting made a good faith effort to evenly translate the planning standard's existing requirements. There are no approved planning standards that contain requirements for 'construction'. While the word, 'constructed' did appear in the 'S' statements, this was viewed as a high level goal or purpose, but there was no specific requirement or measure requiring construction of facilities and that is why such requirements were not added in Version 0.

TVA – Mitchell Needham

TVA supports the Version 0 standards translation, and urges additional progress on those planning standards which had not completed the necessary due process.

Consideration:

The drafting team appreciates your support of Version 0 and shares your concern that the planning standards that were removed from Version 0 should be developed as rapidly as possible while following the ANSI accredited process.

Wisconsin Electric Power Marketing – James Keller

Ballot Recommendation:

I recommend an affirmative vote with comment (below) on the NERC v.0 standards. Ballot deadline is Dec 13th. The success of the initial ballot is unlikely, and an effort to address comments and conduct a re-circulation ballot will take place in early Jan 2005. The target is still NERC BOT adoption of these standards Feb 8, 2005 with compliance monitoring starting April 1, 2005.

Comments/corrections:

1. Standard BAL-006 indicates a regional difference: "MISO RTO Inadvertent Interchange Accounting Waiver approved by the Operating Committee on March 25, 2004." This waiver is not included in the "Index of Regional Differences in Reliability Standards". The Index should be updated to reflect this waiver.
2. Standard INT-001 R2.2 states: " To replace unexpected generation loss, such as through prearranged reserve sharing agreements or other arrangements, and all emergency Transactions to mitigate System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) violations. Such interchange shall be tagged within 60 minutes from the time at which the Interchange Transaction begins."

   Existing Policy 3.A.2.1 states: "Interchange Transactions established to replace unexpected generation loss, such as through prearranged reserve sharing agreements or other arrangements, are exempt from tagging for 60 minutes from the time at which the Interchange Transaction begins (tagged by the Sink Control Area)."

   The Standard INT-001 R2.2 should be changed to continue the "are exempt from tagging for 60 minutes".

Consideration:

The drafting team did not intend to omit any existing waiver that is still applicable after the translation of the Version 0 standards. The referenced waiver will be added to the index of waivers as requested. Additionally, the drafting team will update the index to show the final disposition of all existing waivers.

The drafting team modified INT-001 Requirement 2.2 in the errata sheet because the Interchange Subcommittee commented on a conflict introduced by lumping into the same requirement emergency transactions to address SOL and IROL limit violations and transactions used to replace a loss of generation. Emergency transactions to address SOL or IROL limit violations have different tagging requirements that are addressed in INT-004 Requirement 1.

In making this correction, the drafting team had to make an interpretation regarding what the intended requirement was for tagging emergency transactions to replace a generation loss. The drafting team consulted with the Interchange Subcommittee to determine the original intent of the Policy 3 language. On that basis, the drafting team proposed the following requirement in the errata sheet for INT-001 Requirement 2.2:

If the duration of the Emergency Transaction to replace the generation loss is less than 60 minutes, then the Transaction shall be exempt from tagging.

This compares to Operating Policy 3A 2.1, which states:

INTERCHANGE TRANSACTIONS *established to replace unexpected generation loss, such as through prearranged reserve sharing agreements or other arrangements, are exempt from tagging for 60 minutes from the time at which the* INTERCHANGE TRANSACTION *begins.*

One difference between the policy and the proposed standard is whether the exemption should apply if the transaction is ‘less than 60 minutes’ in duration, rather than ‘60 minutes or less’. This seemingly small difference is significant if a common practice is to schedule the replacement transaction for 60 minutes. There are other ambiguities regarding what emergency transactions have to be tagged and when.

Recognizing there is not a single agreed upon interpretation of the existing policy and no opportunity at this point to vet alternative views in the Version 0 standards, the drafting team is leaving the requirement as currently stated in the errata sheet. The drafting team recommend that the Interchange Subcommittee immediately prepare a SAR to propose revisions to address the remaining ambiguities before, or as soon as possible after, the implementation of the Version 0 standards.

Wisconsin Electric Power Company – Linda Horn

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