NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

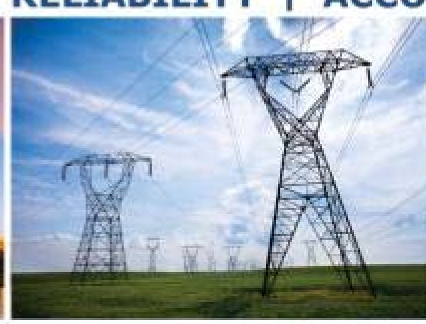
Consideration of Comments Summary

Project 2012-05 ATC Revisions (MOD A)

December 11, 2013

RELIABILITY | ACCOUNTABILITY



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Comment Form
Combined Question 1 and Question 2 Summaries

The Project 2012-05 ATC Revisions Drafting Team thanks everyone who submitted comments on the MOD-001-2 standard. The standard was posted for a 45-day public comment period from October 4, 2013 through November 20, 2013. Stakeholders were asked to provide feedback on the standard and associated documents through a special electronic comment form. There were 28 sets of responses, including comments from approximately 114 people from approximately 76 companies, representing nine of the 10 Industry Segments.

All comments submitted may be reviewed in their original format on the standard's project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, please contact Vice President and Director of Standards Mark Lauby at 404-446-2560 or mark.lauby@nerc.net. There is also a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf

Introduction

The standard drafting team (SDT) appreciates industry comments on the second posting of the MOD A draft MOD-001-2 and associated documents.

Independent Experts Review Panel Recommendations

Northeast Power Coordinating Council (NPCC) and Independent Electric System Operator (IESO) commented that the requirement for developing a written methodology (or methodologies) for determining Total Flowgate Capability (TFC) or Total Transfer Capability (TTC) (as per Requirement R1) should be moved to a FAC standard (e.g., FAC-013), if not already adequately covered by a related FAC standard. Also, NPCC and IESO stated there is some degree of overlap between Requirement R1 of MOD-001-2 and the FAC standards. The SDT does not view moving the requirement to the FAC standards as within the scope of the project. The primary focus of this SDT is to address outstanding FERC directives. NERC noted that the Independent Expert's Review Panel recommended modifications to the grouping of certain Reliability Standards. When these recommendations are considered for implementation, the movement of Requirement R1 to a FAC standard may also be considered by a future drafting team.

Additionally, the SDT concluded that there is no overlap between the proposed Requirement R1 and the FAC standards. The FAC standards address facility ratings and System Operating Limits (SOLs) (among other items), which are utilized in Requirement R1 to develop the TFC or TTC. Further, while FAC-013-2 addresses transfer capability in the planning horizon, it does not develop a TFC or TTC for the operating horizon—as is the case in MOD-001-2, Requirement R1. There are no FAC standards that address the development of TFC or TTC in the operating horizon or for use in the determination of AFC or ATC.

Purpose Section

MRO NERC Standards Review Forum (MRO NSRF), Southwest Power Pool Standards Review Group (SPP SRG), and Southern Company commented that the term "Bulk-Power System" should be replaced with "Bulk Electric System," because Bulk-Power System is not defined. The SDT chose to keep the term "Bulk-Power System," which is now a defined term in the NERC Glossary. As approved by FERC on July 9, 2013, Bulk-Power System is defined as:

> (A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and (B) electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy.[2]

MRO NRSF also commented that use of the term "Bulk Electric System" would "pull in any <100 kV systems that MOD-001-2 would be applicable too." The SDT noted, however, that use of the term "Bulk-Power System" is appropriate for the purpose statement of the standard as it does not specifically exclude or include systems based on voltage level alone.

Independent System Operator/Regional Transmission Organization Standards Review Committee (ISO/RTO SRC), IESO, and NPCC commented that the first sentence of the purpose statement clearly conveys the reliability purpose of the standards, meaning that the proposed second sentence is unnecessary and creates confusion as to the intent of the standard. The SDT agreed with this comment and deleted the second sentence in its entirety. The removal of the second sentence also addresses the commenters' (including Manitoba Hydro's) concern regarding the use of the inconsistent phrases "available transmission system transfer capability" and "available transmission system capability." To be consistent with the title of proposed MOD-001-2, the word "transfer" was

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[2] http://www.nerc.com/files/glossary_of_terms.pdf

deleted from the first sentence of the purpose statement. Southern Company also commented on the use of "other" in the second sentence, which was deleted.

Requirement R1

Florida Reliability Coordinating Council, Inc. (FRCC) provided verbal comments to the SDT about adding a clarifying statement in the rationale for Requirement R1 with regard to whether a Transmission Operator (TOP) must determine TFC or TTC. To address this concern, the SDT added the following statement at the end of the Rationale: "Requirement R1 sets requirements for the determination of TFC or TTC, but does not establish if a TOP must determine TFC or TTC." The SDT noted that the RSAW will also contain this information.

Kansas City Power & Light (KCPL) stated that the term "determining" is the actual act of calculating, and because some registered entities do not make these calculations, those registered entities would not need a methodology. The SDT disagrees with KCPL on the use of "determining" as a synonym for calculating. The terms calculate, establish, decide, maintain, use, develop, provide, produce, determine, find, and more were reviewed. The SDT selected "determine" as the best fit to capture both the situations where a true calculation is performed and others where a limit that was calculated elsewhere is used. No one word was suggested that was above criticism. "Determine" was selected not as the perfect word, but the best fit within the English language. Regardless of the term or phrase used, this test of whether the requirement applies is relatively simple: If the TOP has a value labeled TFC or TTC that it uses for any purpose or passes on to another entity, it has determined a TFC or TTC regardless of how that value was determined. The SDT does agree with KCPL that if an entity does not determine a TFC or TTC, then the requirement does not apply.

SPP SRG commented that the Rationale section should be modified to capitalize "real-time." The SDT made this change throughout the standard.

American Electric Power (AEP), Florida Municipal Power Agency (FMPA), and Oklahoma Gas & Electric (OGE) commented that (1) the responsible entity under Requirements R1 and R4 should be the Transmission Service Provider (TSP)—not the TOP—and (2) the TOP applicability should be removed from Requirements R5 and R6. As discussed in more detail in the Consideration of Comments Summary posted with the second draft of the standard on October 4, 2013,[3] Requirements R1 and R4 correctly apply to TOPs that determine TTC, TFC or Transmission Reliability Margin (TRM) values. The SDT understands that there are different practices across the continent as to which entity (i.e., TSP or TOP) determines TFC or TTC. The standard is drafted in a manner to support these varying practices. The current draft RSAW contains further language that elaborates on this point to alleviate compliance concerns in some of the scenarios in which a TSP performs the TTC or TFC calculations without a Coordinated Functional Registration with the member TOP.

AEP also stated that should TOPs remain as the Responsible Entity under Requirement R1, and the SDT should consider changing "Total Transfer Capability" to "Total Transfer." Because the term "Total Transfer" is not defined within the NERC Glossary, the SDT retained the defined term "Total Transfer Capability." The NERC Glossary definition for Total Transfer Capability provides TOPs latitude in developing methods to determine TTC values for its system.

Arizona Public Service (APS) commented that Requirement R1, part 3.1 implies that (1) the constraints that are requested by another TOP need to be included, and (2) it is not clear if the constraints apply only to thermal constraints or if it also applies to other constraints, such as voltage. The requirement is not limited to thermal constraints. The language of Requirement R3, part 3.1 is intended to cover any type of constraint that is requested

[3] http://www.nerc.com/pa/Stand/Project%20201205%20MOD%20A%20%20Available%20Transfer%20Capabilit/Consideration_of_Comments_Summary_to_Initial_Posting_of_MOD_A_10042013.pdf

to be included. The SDT noted that Requirement R3, part 3.3 allows TOPs flexibility to agree on a process for how to determine whether a requested constraint needs to be included. The SDT chose to provide industry with this flexibility in recognition of the fact that industry previously applied proxy Flowgates for the purpose of including voltage-stability limits. Further, various studies that involve maximum stability-related flows and calculated transfer distribution factors indirectly serve to include consideration of such “other constraints.”

ISO/RTO SRC asked whether there is a definition in the Glossary for the phrase “pre- and post-contingency state” and if the TOP is to define the post-contingency state. There is no NERC definition for the phrase “pre- and post-contingency state.” However, the term “Contingency” is defined as “The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element.” In response, the SDT noted that the TOP must define the post-contingency state.

ISO/RTO SRC also questioned whether Requirement R1, parts 1.2.1 and 1.2.5 are applicable to TFC. The SDT responds that the language in Requirement R1, part 1.2 allows the TOP to designate which elements are parts of their calculation of TFC. Requirement R1, part 1.2 does not require an entity to use all of the items; but requires only that the entity describe the elements it uses. Part 1.2 also includes Flowgate users who do, at times, find those elements are included in their TFC determination; therefore, specifically excluding those elements would not be appropriate.

Manitoba Hydro commented that Requirement R1, part 1.3 would be more accurate if the opening line said: “The process for determining whether to include any reliability related constraints,” as opposed to “including any reliability related constraints,” because it may be determined that the constraints are not be included. In response, the SDT noted that this change would make the requirement optional and weaken the reliability intent. Therefore, the SDT did not make any changes to adding language, but did hyphenate “reliability-related” for consistency purposes within the proposed standard.

Manitoba Hydro also commented that in Requirement R1, part 1.3.2 the words “in its methodology” are missing after the word “describe.” For consistency purposes within the proposed standard, the SDT agreed with the comment and added the missing language.

ACES suggested that the SDT delete Requirement R1, parts 1.1.1 through 1.1.4 because they are SOLs. While this was discussed extensively on several occasions, the SDT ultimately found the term SOL was not applied enough universally to be used alone in part 1.1. The SDT included the elements that generally go into determining an SOL, and added the term “other” to the last item in part 1.1.5 to include SOLs developed by a limit other than those listed in parts 1.1.1 through 1.1.4.

ACES questioned Requirement R1, part 1.3, asking who determines the proper constraints from a requesting TOP. The SDT responds that Requirement R1, part 1.3 and its sub-parts are specific that the requesting TOP makes the request and the TOP doing the calculation must honor it. ACES also asked what would happen if the constraints did not apply. The SDT responds that the testing methodology described in Requirement R1, parts 1.3.1, 1.3.2, or negotiated between entities in part 1.3.3 will ensure that only those constraints that are applicable to the path under study will have influence. ACES then asked, “How is it possible that one TOP has authority over another TOP?” The SDT responds that Requirement R1, part 1.3 makes it clear that one TOP can request another TOP to honor its reliability constraints. There is nothing that precludes discussion between the entities and the modification or withdrawal of a request, but—as a reliability guide—if one TOP asks another TOP to honor their reliability-based constraints, they ultimately must be honored.

ISO/RTO SRC questioned why “planned outages” is used instead of “forced outages” or “known outages” in Requirements R1 and R2. The SDT responded that the determination of AFC, ATC, TFC, or TTC are future-looking values. The phrase “planned outages” is used to account for the outages that the TOP or TSP is planning to account for in their determination. This is similar to the TOP doing operational studies and having outages to plan around. Whether that outage was voluntary or a forced, it is still within the studying and planning horizon. The phrase “planned outage” includes forced outages that need to be planned for. The SDT discussed using “known outages” but preferred “planned outages.” The phrase “planned outages” can be defined by the team. For example, if the Region has an outage-reporting system, then a planned outage may be any outage within that system that feeds the automated TFC, TTC, AFC, or ATC calculation. The phrase “known outage” would not allow that type of clarification.

Measure M1

NPCC, IESO, and ISO/RTO SRC stated that the last bullet in Measure M1 is written as a requirement, not a measure. In response, the SDT modified the Measure. The new Measure reads, “Evidence that currently active TFC or TTC values were calculated based on the current methodology.” NPCC further stated that Requirement R1 does not require a TOP to use its own methodology. The SDT stated that NPCC is correct in the technical sense that Requirement R1 does not require TOP to follow their methodology, but it does require the methodology to reflect their process. The changes the SDT made to Measure M1 should reflect this.

ACES, SERC Planning Standards Subcommittee (SERC PSS), and Manitoba Hydro commented that the approach in Requirement R1, part 1.3.3 is reasonable, but it is not clear on what evidence needs to be maintained. The commenters asked that the drafting team provide a measure for this part. ACES suggested that evidence could include emails, attestations, meeting minutes, or other agreements between the TOPs. In response to this and its own review, the SDT changed the measure to solely reference that a description of the process is necessary within the ATCID and removed any reference to further evidence. The SDT noted the final paragraph of the measure regarding demonstration that the methodology was followed is the appropriate place to include language about receiving a request and following the process. The SDT chose not to call out this language explicitly, however, because verification to the level of tracing a request all the way through the methodology is not necessary on every occasion to measure compliance with the requirement.

ISO/RTO SRC commented that one or more of the sub-bullets under the first bullet do not apply to their method of determining AFC and requested clarifying language. The SDT responded that the parent bullet reads that “methods of accounting for these limits may be included, but are not limited to, one or more of the following,” which allows for only one method or even a different method to be used. The measure does not require that each of the sub-bullets be used. ISO/RTO SRC also commented on the bullet that reads, “A statement that the monitoring of a select limit(s) results in the TFC or TTC not exceeding another set of limits.” This bullet was added to clarify that in the determination of TFC or TTC it is not necessary to simulate or calculate every conceivable limit in detail (e.g., example often limiting operations to within facility ratings is sufficiently restrictive that stability and voltage limits are not reached). The bullet clarifies that the monitoring of the more restrictive set of limits is sufficient and the outer limits do not have to be explicitly monitored.

Requirement R2

FRCC provided verbal comments to the SDT questioning whether a TSP must determine AFC or ATC. Therefore, the SDT added “Requirement R2 sets requirements for the determination of AFC or ATC, but does not establish if a TSP must determine AFC or ATC” to the end of the Rationale for R2.

NPCC and IESO stated they agree with the Independent Experts’ recommendations to remove the requirements for developing an AFCID or ATCID and request NAESB adopt or develop these requirements in their business practices. The commenters stated the implementation documents are intended for calculating the AFCs or ATCs for business usage and do not contribute to ensuring BES reliability. The commenters suggest removing Requirement R2 from the proposed standard. In response, the SDT stated that, as described in the purpose and rationale, the value of AFC or ATC affects the services offered to the market and, when those services are purchased, they affect the BPS as seen by TOPs, TSPs, and others. As such, TOPs, TSPs, and other entities having access to accurate information regarding how AFC or ATC is determined, along with the constituent values, is a reliability need that is protected by Requirement R2. For Flowgate users, Requirement R2 goes further and ensures that overrides are used when available to minimize the chance of oversubscription on a Flowgate.

Manitoba Hydro suggested changing the word “that” in Requirement R2, part 2.1 to “provided such elements.” The SDT made the change, which is consistent with the language in Requirement R1, part 1.2.

Manitoba Hydro questioned whether Requirement R2.2 implies that a TSP should identify reliability constraints using Requirement R1, part 1.3. In response, the SDT noted that Requirement R2, part 2.2 is specific to those TSPs that utilize the Available Flowgate Methodology. This requirement specifies that a TSP that utilizes a neighboring TSP’s Flowgate in the determination of AFC shall use the neighboring TSP’s calculated AFC values.

APS commented that it is unclear what needs to be included in the ATCID to comply with Requirement R2, part 2.1.3. In response, the SDT noted the existing phrase “transmission uses” requires the TSP to include Existing Transmission Commitments (ETC) as applicable to the respective Firm or Non-Firm ATC calculation without specifically calling out all the various types of transmission system use that can be included in ETC. NAESB may consider including in its standards any additional details to further clarify the handling of “transmission uses.”

APS also commented that it is not clear why there are separate documents required for an entity’s ATC, CBM, and TRM. APS stated that CBM and TRM should reside within an entity’s ATCID. In response, the SDT noted that ATC, CBM, and TRM implementation documents are applicable to different functional entities and serve different purposes, and therefore should be separate. However, the standard does not preclude an entity from combining them into a single document.

ACES commented that Requirement R2 should reflect that once TTC or TFC is complete per Requirement R1, then determining AFC or ATC could be a simple algebraic calculation. ACES stated that the requirement as written, in parts 2.1.1 through 2.1.7, implies another Load flow study must be performed to calculate AFC or ATC, which may not be necessary. In response, the SDT clarified that the exact method for determining ATC must be defined in the TSP’s Implementation Documents and stated that the standard does not preclude the use of an algebraic calculation. Some entities use a simple algebraic calculation for the conversion of TTC to ATC; however, other TSPs may wish to use an additional Load flow study to aid in the determination of ATC from AFC. The requirement retains that flexibility.

ISO/RTO SRC commented that “for reliability constraints” should be modified to read “for reliability-related constraints.” The SDT agreed and made the clarifying change.

Georgia Transmission Corporation (GTC) suggested that Requirement R2 should just say “If a TSP determines ATC, then…” with a requirement part regarding having an ATCID and a requirement part regarding following the established ATCID. The SDT worked with the GTC representative on the SDT to draft a conforming requirement, but ultimately decided that the requirement as currently written is sufficiently clear. The requirement establishes when an ATCID is required (if ATC values are determined) and that the ATCID must reflect the current process. Stating that the entity must follow their ATCID or that their ATCID must reflect its process reaches the same destination—an accurate ATCID with a conforming process.

Tennessee Valley Authority (TVA) provided general commentary that the revised standard was too general. The SDT discussed this; however, because it allows for greater flexibility in approaches for addressing new techniques in calculation, new tools, and new challenges on the BPS, the SDT asserts that the revised standard protects reliability to the same or higher level than the existing standard.

TVA provided a specific criticism that the Requirement R2, part 2.2 punishes Flowgate methodology users by requiring they use the AFC determined by the TSP that is responsible for the constraint. The SDT responds that this requirement part was included in the standard at the request of Flowgate methodology users. The requirement part is specific only to the Flowgate methodology because there is no similar concept in the TTC-based methodologies. TVA further requested that the requirement clarify that if the TSP responsible for the constraint does not provide a value, then they should not be required to be use a value. The SDT, including the Flowgate methodology users on the team, discussed this at length and concluded that the current Requirement R2, part 2.2 is sufficient. From the perspective of the TSP applying part 2.2, if they have not received an AFC value from the owner of the constraint, then the owner has not determined one, meaning the TSP is free to handle the constraint per their own methodology.

Measure M2

Manitoba Hydro commented that the last bullet of Measure M2 is about measuring whether or not the TSP is using its current method. It would be more closely aligned with the requirement itself if this bullet was phrased in a way that referred to the methodology being reflective of the current method. In response, similar to the changes for Measure M1, the bullet was modified to address this comment. The SDT revised the Measure while keeping the intent intact. The structure of Measure M2 is similar to Measure M1.

Requirement R3

Southern Company commented that the Rationale had a grammatical error. The SDT corrected the error, replacing “who’s” with “whose.”

SERC Planning Standards Subcommittee commented that the word “determined” should be replaced with “maintained” in Requirements R3 and R4. Further, GTC suggested changing “determined” to “established.” The SDT discussed the appropriate wording in these Requirements and concluded that “determined” is most appropriate and should be used throughout the requirements. “Determine” was selected over “establish” because the team stated “establish” implies that it is the first time a value is set up. “Maintain” was not selected because it implies that the entity takes some sort of action to keep that value in place. “Determine” accurately describes the process for setting this value (i.e., the entity reviews the information available to it and either selects a value directly or makes a series of calculations to set the value, thereby, *determining* the value). For consistency, all instances of “establish,” “establishes,” or “established” were modified to “determine,” “determines,” or “determined” respectively.

NPCC and IESO commented that Requirement R3 does not require a TSP to determine CBM Values, only to have a CBMID that describes its method if it does so. NPCC and IESO state the measure exceeds the requirement by obligating the TSP to determine CBM Values. The SDT agrees that Requirement R3 does not require a TSP to determine CBM values and only requires those TSPs that determine CBM to have a CBMID and follow the methodology in that CBMID. Because Requirement R3 is only invoked *if* the TSP determines CBM values and requires that the CBMID reflect the TSP’s current practices, the measure appropriately expects a demonstration that the CBM values were determined per the CBMID. This demonstration is necessary to validate that the CBMID reflects the TSP current practices, as stated in the requirement. NPCC and IESO suggest removing the requirement and remanding it to NAESB because it is solely a business practice. The SDT agrees that the choice and method of determining CBM is a business practice outside the scope of NERC’s standards; however, if CBM is determined, it does affect AFC and ATC values. Therefore, mandatory disclosure of an accurate description of the TSP’s practice to other entities is a reliability issue.

GTC suggested that the second sentence in Requirements R3 and R4 be modified to state that the entity must develop values based on its methodology. The SDT replied that the purpose of the standard is not to ensure that an entity can write a methodology and follow it, but instead to ensure that an entity has a methodology that accurately reflects its process and can be shared with others.

Measure M3 and M4

For consistency with the requirement, Manitoba Hydro suggested changing Measure M3 to refer only to TSPs that determine CBM. In response and based on comments to the initial posting of the standard (July 11, 2013 to August 27, 2013), the SDT modified Measure M3 to include examples of evidence that entities that do not determine CBM may provide to demonstrate compliance with the requirement. The SDT noted that it is important for the Measure to contain various ways in which entities may comply with the requirement based on particular circumstances.

SERC PSS and ACES suggested changing “affidavit” to “attestation” in Measures M3 and M4. The SDT made this clarifying change as an attestation is the appropriate evidence, consistent with Compliance Application Notice (CAN)-0030. Attestations may be provided to Compliance Enforcement Authorities (CEAs) to demonstrate compliance where other forms of evidence are not available.

Requirement R4

Similar to their comments on Requirement R3, NPCC and IESO stated that Requirement R4 does not require a TOP to determine TRM Values; it only requires the TOP to have a TRMID that describes the method it uses, if it has one. NPCC and IESO also voiced that the measure exceeds the requirement by obligating the TOP to show determined TRM values. The SDT agrees with NPCC and IESO that Requirement R4 does not require a TOP to determine TRM values but only requires that the TOP have a TRMID and to follow the methodology in the TRMID. Because Requirement R4 is only invoked *if* the TOP determines TRM values and requires that the TRMID reflect their practices, the measure appropriately expects a demonstration that the TRM values were determined per the TRMID. This demonstration is necessary to validate that the TRMID reflects the TOP’s current practices, as stated in the requirement. NPCC and IESO also suggest removing the requirement and remanding it to NAESB. The SDT agrees that the choice and method of determining TRM is a business practice outside the scope of NERC’s standards; however, if TRM is determined, it does affect AFC and ATC values, making mandatory disclosure of an accurate description of the TOP’s practice to other entities a reliability issue.

GTC commented that, similar to previous requirements, the language needs to be consistent within the requirement. The SDT modified the requirement to change all instances of “establish” to “determine” for consistency purposes.

Requirements R5 and R6

The SDT received numerous comments on Requirements R5 and R6. In particular, APS and IESO recommended the merging of the two requirements. To varying degrees, ACES, NPCC, IESO, and ISO/RTO SRC questioned the reliability need for the requirements and the clarity of having two entities responsible for the same requirement. The SDT concluded that because Requirements R5 and R6 serve two distinct reliability needs, they should remain as separate requirements in the standard. The SDT also concluded that the requirements are sufficiently clear as to the responsibilities of TSPs and TOPs.

Requirements R1, R2, R3, and R4 require documentation of the methods for developing their respective ATC/AFC, TTC/TFC, CBM, and TRM values; however, the requirements do not require the disclosure of those methods to other functional entities that need to understand those methodologies for reliability purposes. Requirements R5 and R6 provide this mechanism. A fundamental principle underlying this standard is that because AFC and ATC values measure available transmission capacity to be sold to the market, there are reliability implications when that capacity is sold and used. The values do not solely impact the TSP that posts the AFC or ATC value and sells the service, but it affects TOPs, RCs, and other TSPs. The amount of transmission that is available and sold impacts the manner in which operators and planners of the grid carry out their job functions. As such, it is important for these entities to understand the methodologies for determining ATC/AFC and have access to the data underlying those values.

While Requirement R5 addresses disclosure of methods, Requirement R6 addresses forward-looking data to support a neighboring entities' calculation. Requirement R5 allows any entity with a demonstrated reliability need to obtain the methodologies and see clarification of any element contained in those methodologies. Requirement R6 allows TOPs and TSP to obtain system data from other TOPs and TSPs. As stated in Requirement R6, if an entity has data it used to determine AFC, ATC, TFC, or TTC and another TOP or TSP requests access to that data for use in their own determination of those values, then the data must be provided. Requirement R6 is necessary for reliability because, without this requirement, a neighboring entity can be forced to estimate a value (e.g., a neighboring system's Load forecast) rather than use that entity's own Load forecast.

Requirements R5 and R6 are very specific in how they are invoked; that is, through a written request that cites the requirement. This written request for information or system data was included to lower the administrative burden for most entities.

In response to comments from NPCC, IESO, and ISO/RTO SRC that the requirements could be subject to interpretation because they list the TOP and the TSP as responsible entities, the SDT stated that it does not believe the language in the standard is unclear with respect to each entity's obligation. An entity that receives a request for its methodology, a clarification, or its data can only provide the requested material if it is the functional entity with that material. For instance, should a TOP receive a request to clarify an element of ATCID, the TOP should respond that it does not calculate ATC and therefore can provide no further insight.

Manitoba Hydro asked for clarity on the phrase "demonstrating a reliability need" and how it should be assessed. The SDT noted that there are other FERC-approved NERC Reliability Standards that use the phrase "reliability-based need" or "reliability need." For clarification, a Planning Coordinator (PC), Reliability Coordinator (RC), TOP, TSP, or Transmission Planner (TP) would not need to demonstrate a reliability need under the standard. That qualification only applies to other functional entities. Lastly, the TOP and TSP would be the entities to determine if a requestor has demonstrated a reliability need.

SPP SRG made several grammatical suggestions to the Rationale for Requirement R6. The SDT reviewed the language and made several grammatical edits (e.g., "TOP and TSP" to "TOP or TSP" and "are" to "is").

Manitoba Hydro commented that there is no guidance given as to the meaning of "on an ongoing basis." Manitoba Hydro suggested that the word "beginning" be added before "on an ongoing basis." By the phrase "on an ongoing basis," the SDT is referring to data such as Load forecasts or expected interchange that would be provided on an hourly, daily, or other ongoing incremental basis.

Manitoba Hydro also commented that "at regular intervals" was removed from the requirement, but remained in the measure. The SDT deleted "at regular intervals" from the measure.

Manitoba Hydro commented the punctuation in Measure M5 results in the measure not matching the requirement. Manitoba Hydro commented that the measure should be rewritten as follows: "Examples of evidence include, but are not limited to, dated records of the request from a Planning Coordinator, Reliability Coordinator, Transmission Operator, Transmission Planner, Transmission Service Provider, or another registered entity who demonstrates a reliability need, and the Transmission Service Provider's response to the request, or if no requests have been received, a statement by the Transmission Service Provider that they have received no requests." The SDT stated that the measure is clear in what the examples of evidence are for any request and has not made any changes to the measure to be explicit as to who the request is coming from.

MOD-001-2 Compliance Section Comments

Violation Severity Levels (VSLs)

ISO/RTO SRC suggested that the following be moved from a High VSL to Moderate: "Each Transmission Operator that determines TFC or TTC has not used (i) an impact test process for including requested constraints, (ii) a process to account for requested constraints that have a five percent or greater distribution factor for a transfer between areas in the TTC determination, or (iii) a mutually agreed upon method for determining whether requested constraints need to be included in the TFC or TTC determination. (1.3.1, 1.3.2, 1.3.3)" for Requirement R1. The SDT noted that the designation of this VSL is appropriate as it does not meet the majority of the intent of the requirement, but does meet some of the intent.

Manitoba Hydro commented that including "any" in the VSL for Requirement R1 could be interpreted to mean "any one of." In response, the SDT noted that the VSL is gradated; from not including one limitation, not including two limitations, or not including any limitations. The VSL maps to those entities that do have a TTC or TFC methodology, but no limitations are included.

ISO/RTO SRC suggested moving Requirement R2's VSL from High to Low because the TSP is still calculating AFCs. In response, the SDT noted that it is under the impression the commenter is referring to those entities determining AFC or ATC not following its current practices. The VSL is mirrored to follow the existing FERC approved VSL for MOD-001-1a calling for the entity to keep the document current. The SDT noted that the VSL is appropriate.

Manitoba Hydro commented that the VSLs for Requirements R3 and R4 are not consistent with the language in the requirements. The VSLs contain language for entities that "use" CBM or TRM, while the requirements contain language for entities that "determine" CBM or TRM. Therefore, the SDT revised the VSLs to match the language in the requirements and measures (i.e., determine).

Manitoba Hydro commented that the VSLs for Requirement R5 do not exactly correlate to the language in Requirement R5. The language in the requirement reads that the TOP or TSP must respond to a written request in writing, while the VSL does not specify that it must be in writing. To mirror the language and increase the clarity, the SDT added "in writing" after "respond" to the VSLs within Requirement R5.

ACES commented that the term "current" could potentially result in negative impacts for enforcement. ACES stated that it appeared as if an entity is not including one limitation in its methodology would result in a lower VSL. However, if circumstances changed and the entity were required to add a limitation but it chose not to, then its written methodology would not be current, which would result in a severe violation. ACES recommended removing the "current" language from the VSLs because it could be misinterpreted. In response, the SDT noted no changes were necessary as the VSL mirrors the requirement language and is therefore appropriate.

TVA stated that the VSLs for Requirements R3 and R4 should not be severe. Per the VSL Guidelines,[4] the assignment to a severe VSL is appropriate. Because a binary requirement is a "pass or fail" requirement in which any degree of noncompliant performance results in totally or mostly missing the reliability intent of the requirement, the single VSL must be "Severe."

[4] North American Electric Reliability Corp., Order on Violation Severity Levels Proposed by the Electric Reliability Organization, 123 FERC ¶ 61,284 (2008)("VSL Order"), order on rehearing and clarification, 125 FERC ¶ 61,212(2008).

The SDT responded to GTC stating that the appropriate clarifying changes in the requirements were made in the VSLs.

Compliance

Manitoba Hydro suggested that the SDT modify the language in Compliance Section 1.3 because it refers to "a process found in the NERC Rules of Procedure." Manitoba Hydro noted that it has its own Compliance and Monitoring program and has only adopted select aspects of the NERC Rules of Procedure. To address Manitoba Hydro's concern, the SDT deleted the reference to NERC Rules of Procedure to clarify that Section 1.3 simply provides an explanation of the term "Compliance Monitoring and Assessment Processes" and is not meant to refer to any specific process found in the NERC Rules of Procedure.

ACES questioned the need for the standard to require a five-year evidence retention period for implementation and methodology documents. ACES stated that the TOP will be audited every three years, meaning five years of evidence is unnecessary. The SDT retained the five-year retention period on implementation and methodology documents to line up with the FERC directive on retention (S- Ref 10204[5]). The SDT does not believe that this retention period presents a significant burden to industry.

Draft Reliability Standard Audit Worksheet (RSAW) and Compliance Input

ACES commented that while the compliance input was appreciated, it would help to have SDTs reach out to compliance during the informal development process and post compliance guidance and a draft RSAW with each standard during the initial posting. In response, the SDT noted that it was a milestone to have the RSAW posted prior to the second ballot. The SDT understands that the coordination between SDTs and Compliance is an evolving process and that this posting of the MOD A draft RSAW was a step in that evolution.

ACES also commented that there are several statements in the compliance guidance where an auditor will focus on the most recent values instead of historical evidence and that audit teams would be looking forward to ensuring an entity is following its methodology to determine a given value. ACES supports this approach, which is consistent with the Reliability Assurance Initiative (RAI). The SDT has considered this comment and agrees with ACES.

General Comments

Southern Company commented that acronyms were used inconsistently within the standard. In the Rationales, all acronyms are spelled out on first use (the acronyms shown in parentheses) and then used as acronyms throughout the remainder of the Rationales. This is because the Rationales will be moved from the Reliability Standard after the Board of Trustees adoptions. However, within the standard, the functional entities are spelled out while other proper nouns, such as Available Transfer Capability, are used as acronyms. This is because the requirements are auditable and enforceable and the functional entities are spelled out in the rest of the NERC Reliability Standards.

Reliability*First* commented that proposed MOD-001-2 lacks any measurement of whether the communication of available of transmission service is accurate. Reliability*First* believes that the addition of a requirement to verify that past communications of service availability were accurate would be an improvement. For consideration, Reliability*First* recommends a requirement for periodic analysis of the communication of transmission service

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5 http://www.nerc.com/pa/Stand/Project%20201205%20MOD%20A%20%20Available%20Transfer%20Capabilit/Consideration_of_Directives_MOD_A_11122013.pdf

capability. Requirements R1 (part 1.2) and R2 (part 2.1) of the proposed standard require that a TOP's and a TSP's models for determining TFC, TTC, AFC or ATC, respectively, account for system topology, including additions and retirements as well as expected system usage, planned outages, Load forecast, and expected generation dispatch when such elements impact the determination of TFC, TTC, AFC, or ATC. By describing how its methodology accounts for these elements, adjacent systems will be able to effectively model their own transfer or Flowgate capabilities. The SDT concludes, however, that because each part of the country has a different sensitivity to these elements and the frequency with which they change, there is no additional reliability benefit in mandating the frequency with which a TOP or TSP must benchmark or update its models. Under Requirement R6 of the proposed standard, registered entities are required to share their data with others, which also increases the amount of up-to-date information available for the determination of AFC or ATC values. Additionally, under Requirements R5 of the proposed standard, a TSP or a TOP could be asked to clarify its benchmarking or updating practices, if not already set forth in its documented methodology. As such, the proposed reliability standard addresses FERC's directive toward increasing accuracy by improving transparency.

GTC provided grammatical suggestions for Requirements R2, R3, and R4 as well as the appropriate requirement parts. The SDT considered the grammatical suggestions and made the requirements consistent in the terms used (see the "determine" vs. "establish" comment response).

Portland General Electric commented that previous MODs specified the allowable TTC limits that can be applied for counter flow schedules and suggested that there should be more required in MOD-001-2 to provide some level of guidance for schedules in the direction counter to prevailing flows. In response, the SDT stated that by making MOD A less prescriptive, it allows individual entities or individual Regions the freedom to institute something tailored to their own specific needs and concerns.