Individual or group. (31 Responses)
Name (17 Responses)
Organization (17 Responses)
Group Name (14 Responses)
Lead Contact (14 Responses)
Question 1 (27 Responses)
Question 1 Comments (30 Responses)
Question 2 (25 Responses)
Question 2 Comments (30 Responses)
Question 3 (25 Responses)
Question 3 Comments (30 Responses)
Question 4 (26 Responses)
Question 4 Comments (30 Responses)
Question 5 (24 Responses)
Question 5 Comments (30 Responses)
Question 6 (23 Responses)
Question 6 Comments (30 Responses)

Individual
Chris Mattson
Tacoma Power
Yes
A) This standard is the correct document to address all types of UVLS schemes whether they depend on local relaying, local relaying in conjunction with remote arming, or use transfer trip between substations. Including only fully distributed UVLS programs leaves a reliability gap for other types of UVLS programs. Tacoma Power proposes removing the word “distributed” throughout the SAR. Alternatively, the word “distributed” could be added to this standard’s name to make clear that this standard only applies to a subset of automatic UVLS programs. If this standard only applies to a small subset of UVLS programs, another standard will have to be created to fully address FERC order 693. B) Under the description of what “The revised standard WILL NOT: -1) Revise the second bullet point to read “Apply to relays that are used exclusively to protect local areas.” Although coordination of local relays is obviously preferable to miscoordination, the existing bullet point suggests undervoltage relays protecting local loads would be covered if they are coordinated. -2) In the third bullet, the term “centrally controlled or centrally-armed” should be replaced with “centrally tripped. ” Although not designed explicitly as a central arming scheme, many utility SCADA systems have capabilities equivalent to a central arming scheme.
Yes
Tacoma Power fully supports combining all UVLS requirements into a single standard. The flowchart from the webinar incorrectly classifies some UVLS programs as SPSs; the NERC

Glossary definition of SPS specifically states that an SPS does not include undervoltage load shedding. The flowchart from the webinar implies the need for new definition of “Centrally Controlled UV-based ALSP.” Although using remote quantities or values other than voltage can present different risks than strictly using undervoltage relays, excluding such systems from this standard undermines the SAR objective of an “integrated and coordinated approach.” UVLS programs are often designed as safety nets rather than as responses to required category B or C contingencies. The result of overclassifying UVLS programs as SPSs may result in utilities removing UVLS programs to avoid the complex requirements associated with SPSs.
No
A) The definition should use BES rather than BPS. In the webinar, the presenter indicated BPS was chosen so that the definition included “facility and control systems” rather than just Transmission Elements. Although UVLS programs consist of control systems, the point of control systems is to protect the Transmission Elements. Considering that the industry has spent significant effort to precisely define BES, using the term BPS injects unnecessary ambiguity. B) The word “coordinated” should be removed from the definition. Including the word “coordinated” in both the definition and in requirement R1 is redundant. A UVLS plan would be exempt simply if it was intentionally uncoordinated. C) A major reason for this revision is to consolidate all the UVLS requirements into a single standard. Unfortunately, the proposed definition excludes many UVLS programs and instead categorizes them as SPSs or as unregulated “Centrally Controlled UV-based ALSP.” Tacoma Power proposes removing all references to centrally armed or centrally controlled relays and instead substituting the term “centrally tripped.” Using the term “centrally tripped” indicates near real-time central control, whereas “centrally armed” indicates that the final tripping decision occurs via relays at the local level. Alternatively, an additional standard could be developed to cover the excluded UVLS programs. As written, the standard fails to meet the Industry Need as stated in the SAR for “clear and comprehensive requirements.” D) Many SCADA systems include the capability to either change Relay Settings Groups via an RTU control point or to remotely change settings in a microprocessor based relay. Although not designed explicitly as a central arming scheme, these capabilities can be interpreted as centralized control of a UVLS program. Again, Tacoma Power proposes removing all references to centrally armed or centrally controlled relays. E) The definition as written attempts to include a requirement to avoid single points of failure. However, there are situations where a single failure would still result in failure of the UVLS program. Instead of embedding requirements in the definition, there should be numbered requirements similar to PRC-012-1 R1.2& R1.4 requiring all UVLS programs to consider single points of failure. In the currently proposed standard, some distributed schemes may fail to arrest voltage collapse if a single voltage transformer or a single undervoltage relay is used to shed a large portion of the required load to be shed. The proposed new requirements are: R11. The UVLS programs shall be designed so that a single component failure does not prevent the BES from meeting the performance requirements as defined in Reliability Standards TPL-001-4. R12. The inadvertent operation of the UVLS program shall meet the same performance requirements (TPL-001-4) as that required of the contingency for which it was designed. F) The prohibition on using only voltage inputs from

locations other than the load shedding bus should be removed for the following reasons: 1) In a distribution station, the proposed rationale would not allow using the high side voltage for tripping the low voltage feeders. Interrupting the high voltage side results in less flexibility to continue supplying critical loads and may lengthen restoration times. 2) A common configuration for an undervoltage load shedding program is to trip a radial transmission line emanating from a major substation. In system models, the loads are at the individual downstream distribution substation buses. The draft standard would consider this “Centrally Controlled UV-based ALSP.” G) The exclusion definition would be clearer using the defined term Adverse Reliability Impact rather than “adversely affect the BPS.” H) The term “local” should be revised to “local area.” Including the word “area” indicates that the undervoltage condition can apply to multiple substations and is similar to the language used in the BES definition. As per various NERC documents, the term “local” can mean anything from a single distribution feeder up to a Transmission Operator’s entire system as indicated in the following definitions: 1) NERC Guidelines for Developing an Under Voltage Load Shedding (UVLS) Evaluation Program (2006) – definition of “Locally applied UV relay schemes”: intended to protect the local load – such as large induction motors, typically on a single distribution feeder. 2) NERC Glossary of terms-definition of “BES LN”: A group of contiguous transmission Elements operated at or above 100 kV but less than 300 kV that distribute power to Load rather than transfer bulk power across the interconnected system. LN’s emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customer Load and not to accommodate bulk power transfer across the interconnected system. 3) TPL-004-1 – examples of “local area events”: Loss of a major load center. 4) NERC Glossary of terms - definition of “Transmission Operator”: The entity responsible for the reliability of its “local” transmission system, and that operates or directs the operations of the transmission facilities. I) The revised rationale would state: This definition for the term Automatic UVLS Program includes automatic load shedding programs that utilize distributed voltage inputs near to load shedding buses. Therefore, its implementation and reliable performance is inherently not susceptible to Misoperation or inadvertent operation due to a single component failure. The definition excludes: * Centrally-tripped load shedding programs primarily based on quantities other than voltage such as generator reactive reserves, facility loadings, or equipment status. * Local area load shedding that is not part of a plan to protect the BES from wide-area severe undervoltage conditions. J) The revised definition would state: An automatic load shedding program consisting of distributed controls or relays that protects the Bulk-Electric System (BES) from the potential effects of severe undervoltage conditions. The following are excluded: * UVLS controls or relays that are used to address local area undervoltage conditions that would not have an Adverse Reliability Impact.
Yes
Yes
Please see comments in section 3. Any requirements to address single points of failure should be stated as requirements rather than embedded in the definition section.

Yes
Tacoma Power supports the use of UVLS programs as a “safety net” for multiple contingencies and extreme events but we are concerned that the existing UVLS regulations have already encouraged utilities to remove “safety net” UVLS capabilities in order to reduce the risk of noncompliance. Increasing the compliance burden for UVLS systems would likely further reduce the number of utilities using “safety net” UVLS programs.
Group
Northeast Power Coordinating Council
Guy Zito
No
Yes
No
The term Bulk Power System (BPS) should not be used in the definition. The term “Bulk Power System” as defined in NERC’s Glossary of Terms comes from the Energy Policy Act of 2005. The Energy Policy Act extends the authority of NERC and FERC over the BPS, which as confirmed by FERC reaches farther than those facilities that are included in the Bulk Electric System (BES). The BES identifies who must comply with NERC Reliability Standards. Replace the reference to BPS under Definitions of Terms Used in Standard with either Bulk Electric System (BES), or as an alternative, with “interconnected transmission system” as proposed in the Purpose statement of Standard MOD-032-1.
Yes
Yes
The Standard needs to be reviewed for the proper use of BES versus BPS. Regarding PRC-010-1 R1 and the automatic switching of devices such as shunt reactors, it is similar to what is mentioned in Requirement R10 of PRC-006-1. Requirement R1 of PRC-010-1 reads: R1. Each Planning Coordinator or Transmission Planner that develops or modifies an Automatic UVLS Program shall coordinate the Automatic UVLS Program with other protection and control systems and generator voltage ride-through capabilities. Requirement R10 of PRC-006-1 reads: R10. Each Transmission Owner shall provide automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission. How is the flow chart used to classify Automatic Load Shedding Programs (ALSP) provided during the webinar on September 17, 2013, planned to be incorporated into the proposed draft Standard PRC-010-1? Regarding Requirement R4, Suggest to add the words “the capability of” after “implement”. R4 will then read: Each UVLS entity shall implement the capability of automatic tripping of load in accordance…” The proposed change is to avoid the misinterpretation that the UVLS entity

needs to implement the actual tripping of load even when not initiated by the threshold voltage or system conditions. The same wording change also applies to Measure M4.
Yes
Group
Southern Company
Wayne Johnson
Yes
PRC-024-1 includes requirements for both the setting specifications (limitations) for generator owner voltage relays and for data reporting. The second part of the statement in the second bullet on page 4 of the revised SAR can better represent PRC-024-1 by stating that "Generator Owner voltage relay setting specifications (limitations) and data reporting requirements necessary for UVLS coordination are addressed in PRC-024-1".
No comment
No comment.
No
The numbering for 4.1.3.2 is incorrectly shown as 4.1.5.2 in Draft 1 of PRC-010-1. Although discussed in the revised SAR that the GO and GOP are not included in the scope of PRC-010-1, it is not apparent from the open endedness of the Applicability section 4.1.3. Please explicitly indicate that GOs and GOPs are not included in 4.1.3. (perhaps using 4.1.3.3).
No comment.
No
Not necessarily "NO", however; since this standard is primarily accountable to the Transmission Planner (8 of ten requirements); and the only UVLS Entity (TO, DP) responsibility is implementing (R4) and reporting to the TP (R9); the standard should be considered to be moved to the TPL family.
Group
PacifiCorp
Kelly Cumiskey
No
Yes
No
PacifiCorp seeks clarification from the SDT on their use of BPS rather than BES in the definition of Automatic UVLS Program. PacifiCorp is concerned that the use of BPS over BES unnecessarily expands the scope of what consists of an Automatic Undervoltage Load Shedding. Also the current exclusion relating to “localized undervoltage conditions that

would not adversely affect the BPS" is too broad and difficult to determine exclusion. PacifiCorp feels the use of BES would be more appropriate.
Yes
No
Yes
Individual
Thomas Foltz
American Electric Power
No
Yes
Yes
Yes
Yes
R1: We recommend replacing "protection and control systems" with "Protection System" from the NERC Glossary. R8: What purpose would the database serve? Perhaps it is simply a means to an end, but the standard does not clearly show the tangible benefits of having such a database nor how it would be used. Its inclusion in the standard is possibly for the sake of completeness, but could it possibly be left outside the standard? Does the team plan to coordinate their efforts on R8 and R10 with MOD-032 project team? We believe it is presumptuous to state that Automatic UVLS Programs that include automatic load shedding programs and that utilize local voltage inputs are "inherently not susceptible to Misoperation or inadvertent operation due to a single component failure." Individual relays *are* susceptible to misoperation or inadvertent operation, however we *would* agree that such load shedding programs would be less susceptible to failure due to components not directly associated with a local bus (i.e., due to system-wide failures).
Yes
Individual
Michael Falvo
Independent Electricity System Operator
No

Yes
Yes
Yes
We generally agree with the Applicability Section but suggest the SDT to review the need to add Transmission Operator to the list of applicable entities on the basis that a TOP may be required to make UVLS selections (enable or disable it) under circumstances it sees appropriate or directed by the Reliability Coordinator. While the PC and TP develop the UVLS program and the TO provides the capability to trip load in accordance with the program, the actual selection of the UVLS may fall under the TOP's responsibility.
Yes
Requirement R4: Suggest to add the words "the capability of" after "implement". R4 will read thus read: "Each UVLS entity shall implement the capability of automatic tripping of load in accordance…" The proposed change is to avoid the misinterpretation that the UVLS entity needs to implement the actual tripping of load even when not initiated by the threshold voltage or system conditions. The same wording change also applies to Measure M4.
Yes
We support the revised SAR and the direction of the proposed PRC-010-1. However, we have the following additional comments: The proposed effective date may conflict with the implementation date of NERC Reliability Standards in Ontario, Canada. To remove this potential conflict, we suggest the phrase "or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities." In the Effective Dates Section be moved to immediately after "by applicable regulatory authorities".
Individual
Don Schmit
Nebraska Public Power District
Yes
Requirements 8 through 10 are all administrative in nature and should be handled outside of the NERC Standards.
Group
Dominion
Connie Lowe

No
Yes
No
Dominion suggests Bulk-Power System (BPS) be replaced with BES.
Yes
Yes
4.1.3 reads “UVLS entities shall mean all entities that are responsible for the ownership, operation, or control of UVLS equipment …” yet applies only to asset owners (DP and TO). The SDT needs to determine whether they intended for UVLS entity to include operating entity and if so, whether they should add TOP.
Yes
Generally yes, but primarily based upon recommendations of the Industry Experts Review Panel. To a lesser extent; FERC Order 693 and the fact that PRC-020 was remanded, rendering standards that rely upon it is somewhat ambiguous.
Group
DTE Electric
Kathleen Black
No
No comments
Yes
Yes
Yes
No
No comments
Yes
Group
c
c
Individual
David Jendras
Ameren

Yes
(1) We believe the need for this standard is vague and recommend analyzing this way; “Of the y (fill in number) events analyzed by NERC over the last 10 years, x (fill in number) voltage issues have continued to contribute to disturbances. (2) We ask the SDT to clarify ‘The revised standard WILL NOT:’ 2nd bullet (bottom of p 3). We suggest “Apply to undervoltage relays not part of a coordinated program. Such undervoltage relay is used to protect local loads.” (3) We believe the title needs to be changed to reflect that it is intended for UVLS for Wide-Area BPS Protection, as UVLS controls and relays for local under-voltage events are excluded. (4) We ask the SDT the following: (a) How do you believe the BPS will be more reliable with this standard? (b) How many reliability events have been triggered by the “lack of coordination” of UVLS programs? (c) How many UVLS relay misoperations have prevented the program from restoring acceptable voltage and have led to instability, uncontrolled separation, or cascading outages?
Yes
(1) We agree with the consolidation approach.
Yes
No
(1) We believe that the Planning Coordinator’s role in this standard should be limited to those activities as defined in the NERC Functional Model, including coordinating and collecting data, coordinating plans, receiving plans and data from Transmission Planners, etc. Planning Coordinators should not be involved in the design, development, or implementation of UVLS programs. Therefore, the Planning Coordinator should be removed from requirements R1, R2, R3, R4, R6, and R7.
Yes
(1) It’s unclear to UVLS entities whether the PC or TP will perform many of the requirements. We prefer the TP only for R1, R2, R3, R4, R6, and R7. Change R10 to state that TP provides to other PC and TP within its Interconnection. (2) We request the SDT to add to requirement R5.1, “Transmission Planner will work to modify UVLS program as needed if deficiencies in performance are identified in the assessment”. (3) We request the SDT to change R8 “or” to “and” in the first line so that the requirement reads “Each Planning Coordinator and Transmission Planner shall maintain an Automatic UVLS Program database containing data necessary to model its Automatic UVLS Program for use in event analyses and assessments of the Automatic UVLS Program at least once each calendar year, with no more than 15 months between maintenance activities”. (4) We request the SDT to change R9 “or” to “and” at the end of the first line so that the requirement reads “Each UVLS entity shall provide data to its Planning Coordinator and Transmission Planner according to the format and schedule specified by the Planning Coordinator or Transmission Planner to support maintenance of each Automatic UVLS Program database”.
Yes

(1) As mentioned above, we generally support the consolidation approach, subject to our comments.
Group
Arizona Public Service Company
Janet Smith, Regulatory Affairs Supervisor
No
Yes
Yes
Yes
Yes
The standard has unnecessary requirements. Other than the Requirements R1 and R5, all other requirements are administrative and are against the spirit of the Results Based Standards. For example, R9, and R10 are about the data submittal and should be covered in MOD standards. Similarly R2, R3, R4, R6, R7, and R8 are administrative in nature and should be removed.
Yes
Individual
Teresa Czyz
Georgia Transmission Corporation
No
Yes
Yes
Yes
Yes
For R1 "…..shall coordinate with other protection….etc" Who are the "other" that the requirement is referring to? Reconsider the use of the word "other" or define what "other" is. For R5 "…an assessment of each Automatic…." In R1-R4….the requirements seem to refer to a SINGLE Automatic UVLS Program. But in R5….it refers to multiple programs. Please provide further clarity.

Yes
Individual
Trevor Schultz
Idaho Power
No
Yes
Yes
Yes, I support the proposed definition of the term Automatic UVLS Program. However, this definition leaves confusion as to how a centrally-armed or centrally-controlled UVLS scheme should be classified since the current NERC Glossary definition for SPS specifically excludes "undervoltage load shedding". The generic use of the phrase "undervoltage load shedding" in the SPS definition could be interpreted as referring to either distributed or centrally armed/controlled UVLS schemes. If "Automatic UVLS Program" is added to the NERC Glossary, the SPS definition should be changed such that "undervoltage load shedding" is replaced with "Automatic UVLS Program". Likewise, other Reliability Standards should be checked for usage of the generic acronym "UVLS" or generic phrase "undervoltage load shedding", and these terms should be replaced with "Automatic UVLS Program", "SPS", or some other more specific phrase.
Yes
Yes
Individual
Andrew Z. Pusztai
American Transmission Company, LLC
No
Yes
Yes
Yes

Individual
Oliver Burke
Entergy Services, Inc.
No
Yes
Yes
Yes
No
Yes
Individual
Anthony Jablonski
ReliabilityFirst
ReliabilityFirst offers the following comments for consideration: 1. Requirement R1 - ReliabilityFirst believes the use of the term “coordinate” in Requirement R1 is ambiguous and could lead to unintended compliance implications. ReliabilityFirst recommends the SDT consider further clarifying the intent behind such intended coordination. The concept of coordination has historically caused confusion within industry and led to a variety of interpretations. This needs to be clarified. 2. Requirement R2 - ReliabilityFirst believes the requirement should specify the minimum mandatory “specifications of the Automatic UVLS Program” and they should be prescribed in the requirement consistent with the associated rationale. ReliabilityFirst recommends the following for consideration: “Each Planning Coordinator or Transmission Planner that develops or modifies an Automatic UVLS Program shall provide [at a minimum, voltage tripping levels, timing, and the amount and location of load to be shed] specifications of the Automatic UVLS Program to UVLS entities.” 3. Requirement R5 - ReliabilityFirst believes the use of the term “significant” in Requirement R5 is ambiguous and could lead to unnecessary delays in performing a needed assessment. ReliabilityFirst recommends the SDT further define what the SDT constitutes as a significant change made to system topology or operating characteristic. Absent further clarification, this may also lead to unintended compliance implications. 4. Requirement R7 - ReliabilityFirst believes that once the Planning Coordinator or Transmission Planner conducts an Automatic

UVLS Program design assessment, it is necessary for the entity to resolve any deficiencies as well. There is little value in performing an assessment unless action is taken to resolve the identified deficiency. ReliabilityFirst recommends the following for consideration: “Each Planning Coordinator or Transmission Planner that identifies deficiencies through its analysis of the Automatic UVLS Program per Requirement R6 shall conduct an Automatic UVLS Program design assessment to address [and resolve] the identified deficiencies within two years of the event.” 5. Requirement R10 - ReliabilityFirst believes the word “calendar” should be added in front of the word “days”. This will help alleviate any confusion on the number of days in which the entity has to provide its UVLS database. ReliabilityFirst recommends the following for consideration: “Each Planning Coordinator or Transmission Planner shall provide its Automatic UVLS Program database to other Planning Coordinators or Transmission Planners within its Interconnection within 30 [calendar] days of a request.”
Group
ISO RTO Council Standards Review Committee (limited members set)
Charles Yeung
No
Yes
Yes
No
Our response and discussion provided for Question 5 explains our support for the applicability of PRC-010-1.
No
We have one proposed change to a requirement and a commentary on the overall scope of the proposed requirements: Some PCs design their system to avoid the need for UVLS and therefore do not have a UVLS program. The standard needs to address the situation when the TP/PC/TOP does not have a UVLS program but the UVLS entity has their own UVLS schemes. The concepts contained within PRC-010-0 R1 should be incorporated within the new standard to ensure that individual UVLS entity schemes that are developed outside or in lieu of a TP/PC/TOP program are coordinated with their TP/PC/TOP. The proposed scope certainly supports reliability of the BES and addresses the FERC Order 693 directive related to coordination of undervoltage protection schemes. Further we support the Results-based approach to reconstitute the related requirements from four existing standards all under PRC-010-1. However, we ask the SDT and NERC in general, to consider making requirements that are not core to the reliability result that is desired, in new ways that obligate entities to perform them, but do not rise to a level of a full numbered requirement that will be subject to FERC approval and the NERC compliance program obligations. The industry is trying to move towards requirements that more sharply focuses its limited resources onto tracking

and documenting the requirements which most directly impact and benefit the reliability of the BES. Requirements that are supportive in nature or administrative in nature – although an important part of what needs to be performed to satisfy reliability – may not always have to be included in a standard as a distinct and measurable requirement. NERC should begin a conversation with industry and regulators to find ways to complement the core reliability impactive requirements with peripheral and supportive requirements through other mechanisms. These other mechanisms would not be requirements in the sense of having to be measured and penalized, but failure to perform such procedures could in fact cause a finding of a violation of the core reliability requirement. As an example, R5 states "Each Planning Coordinator or Transmission Planner shall perform an assessment of each Automatic UVLS Program in its area every five years, or sooner if significant changes are made to system topology or operating characteristics," to: [Violation Risk Factor:] [Time Horizon:] 5.1. Assess each Automatic UVLS Program's continued need and effectiveness. 5.2. Assess the continued coordination of the Automatic UVLS Program with other protection and control systems and generator voltage ride-through capabilities. This requirement would have to be audited and tracked and documented that it is performed –requiring the full compliance resources as a core requirement, R1. Such an assessment every five years is certainly beneficial for reliability – but is not the core results-based requirement for BES reliability. The R1 requirement which dictates what the assessment should entail is the penultimate requirement for which R5 intends to ensure. If R5 was found to be in violation, the ultimate test of a threat to reliability does not end at not having a document showing the assessment was performed five years from the last date, but an actual reliability threat would be a demonstration that R1 was violated because that five year assessment was missed. Conversely, the measure M5 states: M5. Each Planning Coordinator or Transmission Planner shall have dated evidence such as assessment reports or other dated documentation that demonstrates it performed the assessment of the need for and effectiveness of the Automatic UVLS Program and continued coordination of the program with other protection and control systems and generator voltage ride-through capabilities. In other words, such dated evidence to show to an auditor is no assurance that R1 is not in violation. It merely shows an entity has careful record keeping procedures. Truly not the intended "result" of PRC-010-1. So for this example, a possible alternative to having a specific requirement in PRC-010-1 to reassess UVLS studies every five years is to instead have an overall NERC "maintenance" program where all standards which require the performance of a study have a schedule for registered entities to perform reviews of its subject requirements. In this way, the obligation for supplemental activities to meet reliability objectives reside in supporting programs. Other alternatives may be possible as well.
No
Our response and discussion provided for Question 5 explains our support for the direction of PRC-010-1.
Group
Minnkota Power Cooperative, Inc.
Aaron Vander Vorst

No
Yes
No
-Definition Change 1 Replace: “A coordinated automatic load shedding program consisting of distributed controls or relays that…” With: “A set of coordinated, distributed controls or relays that automatically shed load following the detection of low or decaying voltage in order to …” Purpose: A term should not be included in its own definition. UVLS is not defined in the NERC glossary, so it also needs to be spelled out. "or decaying voltage" was added from existing language in EOP-003-2 R4, and may not be necessary. -Definition Change 2 Replace: “…protects the Bulk-Power System (BPS) from the potential effects of severe undervoltage conditions.” With: “…protect the Bulk-Power System (BPS) against Adverse Reliability Impacts caused by severe undervoltage conditions.” (could alternately use the NERC term “Emergency” conditions) Purpose: Use of NERC defined term “Adverse Reliability Impact” provides clarity to what the purpose of the Automatic UVLS Program is. It also helps to clarify what is meant by “localized” in the exclusions section of the definition. -Definition Change 3 Replace: “UVLS controls or relays that are used to address localized undervoltage conditions that would not adversely affect the BPS” With: “UVLS controls or relays that are used to address localized undervoltage conditions” Purpose: TPL-001-4 gives explicit permission for the use of UVLS for local planning purposes including protection of the BES/BPS. Further, forcing all UVLS relays which protect the BPS to be categorized as a program is not consistent with the Rationale statement for the definition, which says “Local load shed that is not part of a coordinated plan to protect the BPS from wide-area severe undervoltage conditions.” The wide-area aspect is captured through use of the term “Adverse Reliability Impact” in the main portion of the definition. -Definition Question Why is BPS used instead of BES? It seems NERC is moving towards use of BES in their formal definition. BES is the preferred term.
Yes
Yes
-Version History Change Under version 1.0 Action, add something to the effect of “and UVLS-related requirements from EOP-003-2”. -R2 Change Add the following to the end of requirement R2: “, including but not limited to, voltage tripping levels, timing, and the amount and location of load to be shed.” Purpose: Minimum specifics listed in the Rationale portion will not exist following the removal of the Rationale section. If the expectation is that these items will be included, they should be explicitly listed. -R4 Change Add the following to the end of requirement R2: “in Requirements R2 and R3” Purpose: Removes any question as to the intent of the requirement -R5 Correction Typo: There is a space missing before the final word “to” of the requirement. -R5.2 Change Replace: “…with other protection and control systems and generator voltage ride-through capabilities.” With: “…as specified in Requirement R1.” Purpose: Repetition of identical language can lead to inconsistent

language when one statement is changed. Referencing R1 instead of repeating the language makes sure there is no inconsistency. -R8 Change Replace: "Each Planning Coordinator or Transmission Planner shall…" With: "Each Planning Coordinator or Transmission Planner that develops or modifies an Automatic UVLS Program shall…" Purpose: Ensures consistency with other PC/TP requirements in the standard, doesn't force this requirement on all PC/TPs.
Yes
I am generally very pleased with the proposed changes, but would strongly prefer to see the aforementioned changes included to provide more clarity to the standard.
Individual
Andrew Z. Pusztai
American Transmission Company
Yes
ATC has the following comment for consideration by the SDT: The direction of the proposed standard is to ensure that an Automatic UVLS Program created by the Planning Coordinator or Transmission Planner is well planned. ATC would like to confirm that this proposed standard will not preclude the use of temporary UVLS installations in the Operating Horizon by the Transmission Operator to ensure BPS reliability during periods of construction or other work on the transmission system.
No
ATC recommends that the subject definition be revised to exclude temporary UVLS used to support outages in the Operating Horizon.
Group
SPP Standards Review Group
Robert Rhodes
No
Yes
No
We feel the definition should refer to the Bulk Electric System (BES) rather than the Bulk Power System (BPS). The drafting team refers to BES later in the draft standard itself. The drafting team has attempted to clarify the exclusion of certain types of protection systems in the exclusions in the definition. Try as they may, it still isn't crystal clear exactly what the definition is trying to exclude. Could the drafting team include additional clarification? For example, the use of Misoperation is a bit confusing in that UVLS schemes can misoperate but they apparently do not Misoperate? We concur with the following comments on this issue

provided by AEP: “We believe it is presumptuous to state that Automatic UVLS Programs that include automatic load shedding programs and that utilize local voltage inputs are “inherently not susceptible to Misoperation or inadvertent operation due to a single component failure.” Individual relays *are* susceptible to misoperation or inadvertent operation, however we *would* agree that such load shedding programs would be less susceptible to failure due to components not directly associated with a local bus (i.e., due to system-wide failures).”
Yes
Yes
We wonder if R8 and R10 are, or have been, coordinated with the MOD B project? In fact, we believe that R8 should be included in the package of standards associated with the MOD B project.
No
We could probably support the proposed PRC-010-1 providing the drafting team addresses the issues we raised in Questions 3 and 5 above. Specifically, use BES rather than BPS, provide additional clarification regarding misoperation and coordinate with the MOD B project including moving R8 to that effort.
Group
Duke Energy
Michael Lowman
Yes
Yes
No
Duke Energy believes that bullet 2 of the Automatic Undervoltage Load Shedding definition needs to be reworded for clarity. It is unclear what “not adversely affect” means in this definition.
Yes
Yes
Duke Energy suggests combining R1 and M1 into one requirement as follows, “R1. Each Planning Coordinator or Transmission Planner that develops or modifies an Automatic UVLS Program shall: R1.1: Coordinate the Automatic UVLS Program with other protection and control systems and generator voltage ride-through capabilities. R1.2: Maintain documentation describing/listing the specific considerations given in the coordination of the Automatic UVLS Program with other protection and control systems and generator voltage ride-through capabilities as evidence of compliance.” By combining R1 and M1, it adds clarity on the expectations of the Automatic UVLS Program. Duke Energy also recommends

rewording R7 to read, “Each Planning Coordinator or Transmission Planner that identifies deficiencies in its analysis of the Automatic UVLS Program per Requirement R6 shall conduct an Automatic UVLS Program design assessment to address and implement the identified deficiencies within two years of the event.” By adding the word implement, it is clear that deficiencies need to be addressed and implemented within 2 years of event. Finally, Duke Energy would like the SDT to discuss whether 2 years is an appropriate time frame to address and implement an identified deficiency. If the deficiency identified is a change to a relay setting, we agree that 2 years is an appropriate amount of time for the change to be made. However, if a line needs to be upgraded or added to the Automatic UVLS Program to address those deficiencies, then 2 years may not be an adequate amount of time to address and implement.
Yes
Group
ACES Standards Collaborators
Jason Marshall
Yes
1) We do not believe there is sufficient data to support the need for a standard for an automatic UVLS program. We do not believe there is a significant amount of UVLS installed on the grid that is not local in nature. If this is indeed the case, then an international standard is unnecessary especially since the standard proposes that it would not apply to UVLS installed for “localized undervoltage conditions”. If a region does have significant UVLS, a regional standard could be written. Has NERC determined how much UVLS is installed on the BES and how much load is covered? If not, we suggest NERC evaluate the regional entity databases on UVLS data that the regional entities are required to maintain per PRC-020. If there is not sufficient data in those databases, than a data request to determine the amount of UVLS installed that protects the BES can be issued. Analysis of this data is necessary since the standard is not intended to require installation of automatic UVLS programs. If there is not significant amount of existing UVLS that protects the BES, then no standard is necessary. 2) If the SAR moves forward, we think there are many changes needed to clarify the SAR. 3) The point in the industry need section stating that voltage issues have contributed to events over the last ten years is vague and needs to be clarified. This is an obvious statement. Voltage issues will always contribute to events in one form or another. Is this an indication that UVLS has failed during events contributing to expansion of the event or that UVLS was needed in some location as a result of the events? If so, please provide additional clarification. If not, then why is it mentioned in a SAR for UVLS? 4) The statement in the industry need section that there is a “need for clear and comprehensive requirements for the application and coordination of undervoltage load shedding (UVLS) as an option to mitigate or address a number of different voltage control concerns” should be modified. UVLS is always an option and the proposed standard will do nothing to further support this as an option. In fact, it will make responsible entities look for other solutions to avoid the compliance burden. This statement should simply state that the need is for “coordation of

undervoltage load shedding when the Planning Coordinator determines there is a need for it". As another option, the purpose statement for the proposed standard could be used. 5) There is one significant issue with writing a standard for UVLS. FERC required NERC to modify the TPL standards such that non-consequential load shedding was only allowed in limited quantities and applications. The standards essentially limit the non-consequential load shedding to 75 MW. The 75 MW was based on a section 1600 data request requiring responsible entities to indicate if they use non-consequential load shedding. Shedding 75 MW of load is most likely going to be performed to address local issues where there is not a significant amount of transmission. Since an automatic UVLS program will result in shedding firm demand for contingencies that do not interrupt the firm demand, the automatic UVLS program would be non-consequential load shed. Thus, can a PC or TP create an automatic UVLS program "that protects the Bulk-Power System (BPS) from the potential effects of severe undervoltage conditions and not violate the 75 MW limitation in the TPL standards? We think the answer is no. 6) The purpose and goal section should state very clearly in bullet 1 that requirements are intended to apply only when the responsible entity determines that an automatic UVLS program is necessary. We understand that it is documented in other places in the SAR that the standard will not require UVLS installation. However, we think this should be documented in additional locations because excerpts of SARs and standards can be quoted and taken out of context. We also think a similar modification should be made to the first bullet of detailed description section. 7) We agree with retiring PRC-020-1, PRC-021-1 and PRC-022-1 and EOP-003-2 R2, R4 and R7.
No
We agree that these standards are not needed and should be retired. However, we question the need for any UVLS standards. We do not believe there is widespread use of "automatic UVLS programs" designed to support the reliability of the BES and to which this standard would apply. NERC could request data on such programs or to evaluate the existing data in the regional entity databases required by PRC-020. This data would then help determine if a UVLS standard is truly needed.
No
1) The question states that this is a revised definition. We can find no such definition in the glossary of terms. If it does exist, we would be interested in seeing the red-line version of the definition so we can see what changed. 2) BPS should not be used in the definition. Because BPS can be much broader than BES, is more ambiguous and could potentially draw in non-BES assets, BES should be used. NERC has provided guidance in the form of a memo to the standards committee that in general standards apply to the BES unless other further specific applicability is necessary to support BES reliability. The additional applicability must be specified in the standard itself. Thus, there should be great justification provided for using BPS rather than BES. Furthermore, we do not see how use of BPS provides specific applicability. In fact, it is not specific but ambiguous and its use will only lead to inconsistent enforcement. We can find no justification in an application guidelines section of the standard or a whitepaper. While we understand that BPS may have been used because much of the UVLS may be installed on the distribution system, its use is not necessary because the

purpose is to protect the BES not the BPS. If drafting team believes the standard should be applicable to non-BES facilities, then additional applicability should be specified in detail in the standard to avoid inconsistent enforcement.
No
1) The PC should be responsible for the design of the automatic UVLS program and not the TP. Dual applicability will only lead to the same confusion that exists with the TPL standards. Both the TP and PC will have to prove compliance with the standard even if the PC has agreed with the TP to perform the design. It will result in unnecessary compliance burdens on the TP and could even lead to conflicting automatic UVLS programs if both entities develop their own programs. This could harm reliability. 2) Section 4.1.5.2 should be 4.1.3.2. 3) Sections 4.1.3, 4.1.3.1 and 4.1.3.2 (written as 4.1.5.2) are confusing. Is the purpose of adding the DP and TO as sub-sections to indicate that these are the only potential UVLS entities? If so, why not write the applicability similar to the DP for PRC-005. It states in one section that the standard is only applicable DPs that own transmission Protection Systems. This would be clearer and consistent with other standards. 4) Section 215(i)(2) of the energy policy act of 2005 specifically prohibits NERC from requiring construction of transmission capacity. Section 4.1.3 could be viewed as requiring the UVLS entity to build transmission capacity because it makes the UVLS entity “responsible for ownership”. Making the UVLS entity responsible for ownership is the same as requiring them to build UVLS which could ultimately serve to expand transmission capacity by preserving SOLs or increasing SOLs.
Yes
1) In R1, BES should be added before generator to clarify that coordination is necessary only with BES generators. Otherwise, the standard could be interpreted to apply to all kinds of distributed generation. Coordination with distributed generation is not practical. 2) R2 meets Paragraph 81 criteria B1 (administrative) and B4 (reporting). It requires the PC or TP to report specifications to UVLS entities which clearly meets the reporting criterion. It is administrative in nature because it is unnecessary. Why would a PC or TP develop or modify their Automatic UVLS program per R1 and not report the changes needed to the UVLS entities? It would make developing or modifying the program superfluous. Thus, R2 is administrative and unnecessary. 3) R3 meets Paragraph criterion B1 (administrative) and criterion B3 (documentation). It requires the PC or TP to provide a schedule for implementation which is the same as documenting the schedule, and it is administrative in nature because it is unnecessary. Why would a PC or TP develop or modify their Automatic UVLS program per R1 and not give a schedule to the UVLS entities? It would make developing or modifying the program superfluous. Thus, R2 is administrative and unnecessary. 4) While we believe R2 and R3 should be removed because they meet Paragraph 81 criteria, they should be combined with R1 if they persist to avoid instances of double jeopardy. R2 and R3 could be made sub-parts of R1. If a registered entity fails to coordinate its Automatic UVLS Program, it will also fail to provide specifications to UVLS entities per R2 and to provide a schedule for implementation to the UVLS entities per R3. Since violations are assessed per requirement, one compliance failure could result in three separate compliance violations of R1, R2, and R3. Thus, if R2 and R3 are written as sub-parts

of R1, failure to coordinate its Automatic UVLS Program and to provide specifications and an implementation schedule will be assessed as a single violation of the combined requirement. 5) To be clear that this standard does not require the creation of a new Automatic UVLS Program where none currently exist, we recommend adding "existing" as an adjective to the Automatic UVLS Program in R5. 6) The rationale for R6 conflicts with the rationale for the definition of Automatic UVLS Program. The rationale states that the analysis conducted in R6 would also include evaluation of relay Misoperations. However, the rationale for the definition states that the "implementation and reliability performance" of the Automatic UVLS Program "is inherently not susceptible to Misoperation". If it is not susceptible to Misoperations why would analysis conducted for R6 include evaluation of Misoperations? 7) R6 has the potential to become a zero defect requirement and does not reflect the actual responsibilities of the PC and TP as defined in the functional model. As written, the PC and TP will have to identify all voltage excursions regardless of their magnitude, identify the subset of voltages excursions below the UVLS setpoints, and present this information to auditors. If they do not show evidence of having reviewed all voltage excursions, how can the PC and TP demonstrate to auditors that they have identified all voltage excursions below the UVLS setpoints? This presents a further problem in that the PC and TP may not have access to the real-time voltage data to monitor the excursions since they are not operating entities. How will the PC and TP know a voltage excursion has occurred when they don't monitor the system or have access to the data? A more practical approach would be to require the PC or TP to evaluate the effectiveness of the Automatic UVLS Program only if the relays actuate not just if there are voltage excursions. This analysis would still result in significant benefit without the threat of zero-defect enforcement of requirements that largely results in paper compliance violations that do little to support reliability. 8) Requirement R7 is vague and ambiguous which will lead to inconsistent enforcement and differing compliance outcomes. The requirement compels the PC and TP to identify efficiencies in its analysis of the Automatic UVLS program in R6. What is meant by efficiencies? This term is vague and will be interpreted differently by different regions and even different auditors within the regions. This will lead to regions or auditors to define what is meant by efficiencies after the fact which will be different from registered entity interpretations and will result in paper compliance violations that do little to support reliability. The drafting team should define very specifically what efficiencies that registered entities should evaluate and identify. 9) Requirements R6 and R7 should be combined to avoid instances of double jeopardy. R7 could be made a sub-part of R6. If a registered entity fails to evaluate the effectiveness of its Automatic UVLS Program per R6 not only will it be assessed a violation of R6, it will also be assessed a violation of R7 because it cannot identify efficiencies without having conducted the analysis. Compliance violations are identified on a requirement basis. Thus, if R7 is written as a sub-part of R6, failure to conduct the effectiveness evaluation and, as a result, failure to identify the associated efficiencies will be assessed as a single violation of the combined requirement. 10) We recommend that R8 should be modified to clarify that it is only required to be performed if the PC and TP have existing Automatic UVLS Programs. This could be accomplished by adding "if they have an existing Automatic UVLS Program" to the beginning of the requirement. 11) R9 meets Paragraph 81 critera B1 (administrative) and B4

(reporting). It requires the UVLS entity to provide data to its PC or TP according to their format and schedule. It is administrative in nature because it is unnecessary. For instance, if the UVLS entity provides the data in a different format than requested by the PC or one day late according to the PC schedule, reliability will not be impacted at all. This only facilitates administration of the PC or TP program. It clearly meets the reporting criterion because it involves data being supplied to a third party by their requested data and in their format. The UVLS entity would have no reason for refusing to supply the data. Refusal to supply the data could only have negative reliability impacts on the UVLS entity because their UVLS relays may become uncoordinated and actuate before otherwise necessary. Any issues can be worked out with simple discussions between the PC, TP and UVLS entities. Furthermore, the PC and TP should already have the data since they supplied the settings requirements previously. Thus, R9 is administrative and unnecessary. Furthermore, this requirement is similar to PRC-006-1 R8 which was proposed to be retired in phase II of the Project 2013-02 Paragraph 81. 12) R10 meets Paragraph 81 criteria B1 (administrative) and B4 (reporting). It requires the PC or TP to provide its UVLS database to other PCs and TPs if they request the data which clearly meets the reporting criterion. It is administrative in nature because it is unnecessary and does not support reliability. It only further perpetuates paper driven compliance. It is very likely that a PC or TP will never receive any requests but they will still have to demonstrate compliance which means they will have to prove they did not receive any requests. Furthermore, why would a PC or TP refuse to supply the database to other TPs and PCs? They have no incentive to refuse. Thus, the requirement is truly superfluous, administrative and unnecessary. Furthermore, this requirement is similar to PRC-006-1 R7 which was proposed to be retired in phase II of the Project 2013-02 Paragraph 81. 13) R8 is similar to the requirement PRC-006-1 R6 which was identified as meeting Paragraph 81 criteria by the Independent Experts Panel. They have recommended it for retirement. Given that these are similar requirements, significant justification should be provided for why it is necessary and does not meet the criteria. Otherwise, it should be deleted.
No
NERC should determine how much UVLS is installed on the BES to protect the BES and how much load is covered before moving forward with an international standard. This data should be readily available because the regional entities should have been collecting the data per PRC-020. After analyzing the data, NERC could determine the appropriate course of action which could include developing an international standard, developing one or more regional standards or not developing a standard at all. If no standard is developed, NERC could use the data to demonstrate to the Commission how the directives have essentially been met because there is not a significant amount of automatic UVLS programs installed to affect the reliability of the BES making the standard superfluous.
Group
Florida Municipal Power Agency
Frank Gaffney

EOP 003-2 also addresses UVLS; changes to EOP-003 have not been posted yet. Assume the next posting will include changes to EOP-003 to eliminate duplication with this new standard.
Individual
Texas Reliability Entity
Texas Reliability Entity
No
Yes
No
The proposed definition needs further clarification. (1) To state in the rationale that a UVLS system is not susceptible to Misoperation is not correct. For example, in the ERCOT region we had a UVLS event where approximately 30% of the entity feeders automatically reclosed following activation of the UVLS protection due to an error in the control logic in the relay. (2) We would suggest removal of both exclusions, and adding references to the BES and TPL Standards. The overarching need for any UVLS protection system is to meet the BES performance requirements as stated in the TPL standards and the UVLS definition should be stated on that basis, whether the UVLS systems is applied for a steady-state, post-contingency, stability, or transient condition. We propose the following definition for Automatic UVLS Program: “A coordinated automatic load shedding program consisting of distributed controls or relays on the Bulk-Power System (BPS) that protects the Bulk Electric System (BES) from the potential effects of severe undervoltage conditions consistent with the Transmission Planning Standards (TPL)”. (3) If the SDT feels that the exclusions should remain, we offer the following comments: (a) The use of the term “localized undervoltage conditions” in the 2nd exclusion needs further clarification as it is open to interpretation. In ERCOT, there are UVLS protection systems in the Dallas-Fort Worth metroplex, Houston, Laredo, and lower Rio Grande Valley areas. Would these systems be considered “localized” and excluded from the Standard? We are proposing the following revision to the 2nd exclusion: “UVLS controls or relays that are not used to address undervoltage conditions in the BES.” (b) Under what Standard will “Centrally-controlled or centrally-armed UVLS controls or relays” be covered if they are excluded from this Standard? They are currently excluded in most regions from being classified as an SPS. Also, in the SPS definition proposed by the NERC SPCS whitepaper, UVLS systems as well as “operator aids” will not be classified as an SPS, so where would these types of systems fit?
Yes

Yes
(1) The overarching need for any UVLS protection system is to meet the TPL standards. This Standard is mute on this topic. The TP/PC must demonstrate that implementation of a UVLS will provide BES performance that is consistent with the requirements in the TPL standards. The requirements in this Standard should be stated in a manner such that the design, periodic assessment, and analysis of actual events for the UVLS system provides the required BES performance, whether the UVLS was developed for either a steady-state, post-contingency, stability, or transient need. (2) In R6, the one-year time frame for analyzing the UVLS performance for an actual event is too long. We suggest following timelines similar to the NERC Events Analysis Process. (3) In R8, we suggest adding additional information to clarify the requirement. The term “maintain” is unclear and ambiguous. What exactly is expected?
Individual
Andrew Gallo
City of Austin dba Ausitn Energy
No
Yes
Yes
Yes
The requirements applicable to "Each Planning Coordinator or Transmission Planner" may provide unnecessary compliance burden on some entities. For example, in a region where the PC solely fulfills the requirement, there is no mechanism for the Transmission Planner to keep that requirement out of scope during compliance activities (e.g. audits) other than for the Transmission Planner to say "trust me, I'm not responsible." Given that we are dealing with two distinct registrations, a CFR matrix will not help. This is particularly applicable to R5, R6, R8 and R10; the others include clarifying phrases such as "...that develops or modifies an Automatic UVLS Program." Austin Energy requests the SDT consider whether it is better: (1) to make the PC the only responsible entity for these requirements or (2) add a clarifying phrase to the TP role.
Yes
Individual
Alice Ireland
Xcel Energy
No

Yes
No
Xcel Energy supports in general the revised definition but suggests enhancing the second bulleted item as follows: Suggestion 1 (preferred): “UVLS controls or relays that are used to address localized undervoltage conditions do not have an Adverse Reliability Impact.” Suggestion 2: “UVLS controls or relays that are used to address localized undervoltage conditions that are not part of a coordinated plan to protect the BPS from wide-area severe undervoltage conditions”
Yes
Yes
1)Given the similarity of structure and verbiage within R1, R2, R3, we note that they lend themselves to be condensed into a single requirement with two parts. Recommend that R1, R2, R3 be combined into one requirement to provide “one-stop” concise listing of all activities to be performed by the applicable entity (PA or TP), as suggested below: [R1. Each Planning Coordinator or Transmission Planner that develops or modifies an Automatic UVLS Program shall: 1.1 coordinate the Automatic UVLS Program with other protection and control systems and generator voltage ride-through capabilities 1.2 provide specifications and schedule for implementation of the Automatic UVLS Program to each UVLS entity] 2)Requirements R5, R6, R7, R8, R9 and R10 should be modified to state “Each Planning Coordinator or Transmission Planner that develops a UVLS Program…”, so that the responsibility for the action in the requirement is upon the function that created the UVLS Program. 3) R10 is confusing…if the TP is the function that developed the UVLS database, is the TP only obligated to provide its UVLS Program database to other PCs “or” TPs? What if the appropriate neighboring entity would be a PC but the database was provided to the TP?
Group
Puget Sound Energy
Eleanor Ewry
No
Yes
Yes
Yes
Yes

Regarding R1, how is it proposed that entities demonstrate coordination between their UVLS program and other protection and control systems? Is it anticipated that this coordination should be demonstrated through a simulation of the interaction between the two, or is coordination of the settings sufficient (i.e timing and set points demonstrate that the schemes will not operate within the same time period)? If actual simulation is required, will consideration be made for the availability of models for the various protection systems? Also, will consideration be made for the ability of software tools to achieve robust solutions for extreme contingency conditions?
Yes
Individual
Larisa Loyferman
CenterPoint Energy
No
Yes
See response to Question 5
Yes
Yes
Yes
General comment: CenterPoint Energy believes that PRC-010-1 SDT has not met the directive of FERC in Order 693 to ensure that an integrated and coordinated approach is being performed. CenterPoint Energy believes that the Planning Coordinator must have the ultimate responsibility to ensure the coordination of ALL Automatic UVLS programs throughout a region. Each Transmission Planner that develops or modifies an Automatic UVLS Program is responsible for coordinating its Automatic UVLS Program with other protection and control systems and generator voltage ride-through capabilities in its area. To avoid confusion, CenterPoint Energy recommends clearly identifying corresponding responsibilities for each of the Functional Entities. Specific comments: 1. Regarding R3, CenterPoint Energy is concerned that the current proposed wording may unilaterally dictate an implementation schedule without conferring with the UVLS entity as to the feasibility of the schedule. CenterPoint Energy recommends a collaborative approach between the Planning Coordinator and UVLS entity to determine a mutually agreeable schedule for implementation of the developed Automatic UVLS Program. 2. Furthermore, due to the possibilities of unforeseen circumstances CenterPoint Energy proposes Requirement R4 to be worded as follows: “Each UVLS entity shall implement automatic tripping of load in accordance with the Automatic UVLS Program specifications and schedule, barring unforeseen circumstances, as determined by its Planning Coordinator.” 3. The rationale for Requirement R6 indicates that UVLS misoperations would be included in the UVLS

“performance” review following a voltage excursion event. CenterPoint Energy believes UVLS misoperation analysis is already addressed by other NERC initiatives and should not be included in PRC-010. UVLS misoperation analysis and review is part of NERC misoperations reporting. 4. CenterPoint Energy suggests the UVLS “performance” review should simply be whether the UVLS successfully resolved the system emergency and if any load shed obligations are met. We recommend that the UVLS “assessment” in Requirement R7 would only be triggered if the UVLS does not resolve the emergency or if a minimum load shed obligation is not met.
Yes
Individual
Catherine Wesley
PJM Interconnection
No
Yes
No
The definition includes the term “localized” which is not a defined term. It potentially could be interpreted differently by auditors and the applicable functional entities. The term needs to be defined clearly to eliminate ambiguity.
Yes
Yes
The PJM Regional Transmission Expansion Plan designs the PJM RTO system to avoid the need for UVLS and therefore PJM does not have a UVLS program. The standard needs to address the situation when the TP/PC does not have a UVLS program but the UVLS entity has their own UVLS schemes. The concepts contained within PRC-010-0 R1 should be incorporated within the new standard to ensure that individual UVLS entity schemes that are developed outside or in lieu of a TP/PC program are coordinated with their TP/PC.
Yes
Individual
Richard Vine
California Independent System Operator
Yes
We question whether the scope should encompass all UVLS relay schemes to ensure coordination between the local and centrally-controlled UVLS relay schemes. We think that all UVLS relay schemes should be contained within the same UVLS database. We think

additional rationale regarding the definition of Automatic UVLS Program would be beneficial to understand why centrally-controlled UVLS schemes and local UVLS schemes are excluded.
Yes
No
We find the definition confusing in that it excludes the centrally-controlled and local UVLS relay schemes. Additional rationale regarding the definition of Automatic UVLS Program would be helpful to understand why centrally-controlled and local UVLS schemes are excluded. With the consolidation of the four PRC standards (PRC-020-1, PRC-010-0, PRC-021-1 and PRC-022-1) into one new PRC-010-1 standard, which standard(s) would now apply to the centrally-controlled UVLS and local UVLS schemes, since they are excluded from the Automatic UVLS Program definition in PRC-010-1.
No
We suggest adding the Transmission Operator (TOP) functional entity as an Applicable entity. An example for why we believe the TOP functional entity should be added is provided in the Requirement and Rationale for R6, which requires within a one-year time frame (operating horizon) from the date of an event to conduct a program performance analysis to evaluate whether or not the UVLS Program responded as intended, and that this analysis would also identify relay Misoperations.
Yes
We have a proposed change to a requirement and a commentary on the overall scope of the proposed requirements: Some PCs design their system to avoid the need for UVLS and therefore do not have a UVLS program. The standard needs to address the situation when the TP/PC/TOP does not have a UVLS program, but the UVLS entity has their own UVLS schemes. The concepts contained within PRC-010-0 R1 should be incorporated within the new standard to ensure that individual UVLS entity schemes that are developed outside or in lieu of a TP/PC/TOP program are coordinated with their TP/PC/TOP. The industry is trying to move towards requirements that more sharply focuses its limited resources onto tracking and documenting the requirements which most directly impact and benefit the reliability of the BES. Requirements that are supportive in nature or administrative in nature – although an important part of what needs to be performed to satisfy reliability – may not always have to be included in a standard as a distinct and measurable requirement.
No
See above response comments to questions 1 -5. (i.e. comments regarding the definition of Automatic UVLS Program.)

Additional comments received from Exelon:

1. Do you have any specific questions or comments relating to the scope of the revised SAR?

☒ Yes
☐ No

Comments: Does R1 really meet FERC's direction for an integrated and coordinated approach to the UVLS systems? R1 discusses coordination, but it does not discuss an integrated approach, which might mean that UVLS should be part of an overall system that protects the BPS from significant events. FERC's requirement for an integrated and coordinated scheme may also conflict with the exclusion of centrally-armed UVLS systems from the standard.

2. Proposed PRC-010-1 consolidates and replaces the requirements previously addressed by PRC-010-0, PRC-020-1, PRC-021-1, and PRC-022-1 in addition to incorporating revisions to meet the Order No. 693 directive and other inputs referenced in the SAR. Do you agree with this approach? If not, please explain your concerns.

☒ Yes
☐ No

Comments:

3. Do you support the revised NERC Glossary term Automatic UVLS Program? If no, please indicate in the comment section what suggested changes would put you in favor of the new glossary term.

☐ Yes
☒ No

Comments: The proposed standard is unclear as to where centrally-controlled or centrally-armed UVLS systems fit in compliance space. If a centrally-controlled UVLS needs to be treated as an SPS, then the revised PRC-010 should say that. The fate of centrally-controlled UVLS is uncertain with the wording in the draft standard. The definition should also incorporate some of the elements in the rationale to provide definition for what is or is not a centrally controlled load shedding program .

4. Do you agree with the Applicability of the proposed PRC-010-1? If not, please explain your concerns.

☐ Yes
☒ No

Comments: The applicability section does not cover legacy UVLS systems that were installed by a utility that has since turned over the responsibility for its planning functions to a transmission planner and is now registered as a transmission owner if the transmission planner does not require UVLS.

5. Please specify if you have comments or suggested changes to any of the draft requirements for the proposed PRC-010-1.

☐ Yes
☒ No

Comments:

6. Do you support the revised SAR and the direction of the proposed PRC-010-1? If no, please indicate what suggested changes would put you in favor of the revised SAR and draft standard.

☐ Yes
☒ No

Comments: The revised SAR is fine. The definition excluding centrally-armed UVLS systems from the standard may require these UVLS systems to be forced into requirements more typical of SPSs, such as redundancy and the more strenuous reporting. This would occur even if the purpose of the central arming is to prevent the UVLS from operating during light load conditions.