Meeting Notes
Project 2016-EPR-02

September 7-9, 2016

PJM
Audubon, PA

Administrative

1. **Introductions**
   The meeting was brought to order by the Chair, S. Solis, at 8:35 a.m. Eastern on Tuesday, September 7, 2016. S. Solis provided the team with general comments and welcome introductions. B. Harm communicated housekeeping items and gave a safety briefing. Participants were introduced and those in attendance were:

Name	Company	Member/ Observer	In-person (Y/N)	Conference Call/Web (Y/N)
Stephen Solis	Electric Reliability Council of Texas, Inc.	Chair	Y	-
Dennis Sauriol	American Electric Power	Vice Chair	Y	-
Alex Chua	Pacific Gas & Electric	Member	Y	-
Kevin Harrison	ITC Holdings	Member	Y	-
Bill Harm	PJM Interconnection, LLC	Member	Y	-
Tim Kucey	PSEG Fossil, LLC	Member	Y	-
Michael Scott	NextEra Energy, Inc.	Member	Y	-
Laura Anderson	North American Electric Reliability Corporation	NERC Staff	Y	-
Scott Barfield-McGinnis	North American Electric Reliability Corporation	NERC Staff	Y	-
Lauren Perotti	North American Electric Reliability Corporation	NERC Staff	Y	-

Name	Company	Member/ Observer	In-person (Y/N)	Conference Call/Web (Y/N)
Juan Villar	Federal Energy Regulatory Commission	Observer	Y	-
Juan Luz	Federal Energy Regulatory Commission	Observer	Y	-
Michael Cruz-Montes	CenterPoint Energy, LLC	Observer	-	Y
Alan Engelmann	Commonwealth Edison (Exelon)	Observer		
Si Truc Phan	Hydro-Québec TransÉnergie	Observer	-	y
Alison Mackellar	Exelon Nuclear	Observer	Y	-
Andy Pusztai	ATC, LLC	Observer	-	Y
Guy Zito	NPCC	Observer	-	Y

2. **Determination of Quorum**
The rule for NERC Standard Drafting Team (SDT or team) states that a quorum requires two-thirds of the voting members of the SDT. Quorum was achieved as all seven members were present each day.

3. **NERC Antitrust Compliance Guidelines and Public Announcement**
NERC Antitrust Compliance Guidelines and public announcement were read by S. Barfield-McGinnis. The group was reminded at the beginning of each day that participants are under the guidelines. There were no questions.

4. **Roster Updates**
The team reviewed the team roster and confirmed that it was accurate and up to date.

Agenda

1. **Review of Notes from Previous Meetings**
During the review of the August 17, 2016 meeting notes, A. Mackellar asked if “voltage schedule” and “voltage limit” were defined NERC terms. S. Solis responded that Project 2015-09 – Establish and Communicate System Operating Limits drafting team would consider the benefits of defining the term “system voltage limit.” A. Mackellar questioned whether the voltage schedule in Requirement R1 and R5 are the same while reviewing the September 1, 2016 notes. S. Solis noted that the “voltage schedule” reference could be the same and is one of the points that the team

needs to discuss further. For example, a Transmission Operator (TOP) could determine the voltage desired at certain controlling buses and then have a specific schedule for Generator Operators (GOP) in order to maintain the desired voltage at its transmission buses. A. Mackellar asked the group if it is typical to address voltage schedules with the Generator Owner (GO) as well as the GOP. Additionally, how are the variations in seasonal operation addressed by others? S. Solis noted that ERCOT has voltage schedules that are adjusted accordingly. From the September 1, 2016 notes, A. Mackellar asked what the intent is concerning the exemption criteria of Requirement R4. For example, is the exemption intended for a blanket exemption or specific to generating units? D. Sauriol noted that it could be specific to a unit because there may be cases of a weak generator with respect to the transmission system may have no material effect on voltage of the system. If too stringent of a voltage schedule is placed on the generator, they may end up with a violation.

2. **Enhanced Periodic Review Grading Review**

VAR-001

The team continued from the September 1, 2016 conference call beginning with VAR-001-4.1, Requirement R5. This requirement uses both "voltage schedule" and "reactive schedule." Some attendees noted that not all entities use the Automatic Voltage Regulator (AVR) terminology. For example, the AVR may be unit specific and the site may have a voltage regulation mark or flag. The team might need to consider the use and/or a definition of the voltage and reactive schedule. S. Solis noted that the team needs to review the Project 2014-03 – TOP/IRO project to see how the requirements were mapped from the original Transmission Operations and Interconnection Reliability Operations (IRO) standards to the new. From the VAR-001, Requirement R5 rationale:

Rationale for R5:

> *"The new requirement provides transparency regarding the criteria used by the TOP to establish the voltage schedule. This requirement also provides a vehicle for the TOP to use appropriate granularity when setting notification requirements for deviation from the voltage or Reactive Power schedule. Additionally, this requirement provides clarity regarding a "tolerance band" as specified in the voltage schedule and the control dead-band in the generator's excitation system.*
>
> *Voltage Schedule tolerances are the bandwidth that accompanies the voltage target in a voltage schedule, should reflect the anticipated fluctuation in voltage at the Generation Operator's facility during normal operations, and be based on the TOP's assessment of N-1 and credible N-2 system contingencies. The voltage schedule's bandwidth should not be confused with the control dead-band that is programmed into a Generation Operator's automatic voltage regulator's control system, which should be adjusting the AVR prior to reaching either end of the voltage schedule's bandwidth."*

There seems to be some level of duplication between VAR-001, Requirement R5, Part 5.1 and VAR-002, Requirement R1. B. Harm believed the original VAR drafting team ended up with two standards to differentiate the performance between TOPs and GOPs.

The team recessed to join the North American Generator Forum (NAGF) call to discuss any concerns of the NAGF members about VAR-001 and VAR-002. The only significant issue from the NAGF call included that the TO should include a time period for complying with the voltage schedule in VAR-001, Requirement R5. A. Mackellar added after the NAGF call that the requirement should have a “magnitude” component of going out of bounds with the schedule. What happens when the generator goes outside of the tolerance band from a requirement standpoint? S. Solis noted that a generator should be holding in the band very well, except when other extenuating conditions are causing the generator voltage to move. Monitoring changing voltage schedules may be taking System Operator attention away from more important matters. Lastly, an NAGF caller raised concerns about issues with variable generation (i.e., wind). For example, certain variable integrated resources may not be able to hold a voltage. Team members added that some fossil plants have no excess capacity when meeting the voltage schedule. The team will need to discuss further.

The team resumed its review of VAR-001, Requirement R5 using comments from the grading spreadsheet. The team believed it would be good to discuss how seasonal voltage schedules are addressed. During the conversation, two sidebar comments were raised about VAR-001, Requirement R4. First, Requirement R4 may need to include the “operations” time horizon. Second, Requirement R4 may need clarity on how the exemption criteria is developed (e.g., blanket or specific).

Continuing with VAR-001, Requirement R5, the voltage schedule and/or Reactive Power schedule. For example, add clarity to “Each Transmission Operator shall specify a [see footnote] voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) at either the high voltage side or low voltage side of the generator step-up transformer at the Transmission Operator’s discretion.” Two additional questions were posed: (1) is there a concern about directing a voltage schedule at one point in time, and (2) are there any unintended consequences if all generators apply a schedule at once? One attendee thought that VAR-001, Requirement R5, Part 5.1 should have flexibility to direct either voltage or reactive control. Additionally, should VAR-001, Requirement R5 have a Real-time component (most believe it would create confusion). From the grading process, in VAR-001, Requirement R5, it would be clearer to specify who is exempted from the schedule. Comments from the Violation Severity Level (VSL) on Requirement R5 noted that the second portion of the Severe VSL may need a High VSL component as well.

K. Harrison suggested that the team may need to define “generator voltage schedule” and “generator reactive Power schedule, “system voltage schedule,” and AVR (could be technology specific) in VAR-001, Requirement R5. S. Solis reminded the group that Requirement R5 uses “voltage schedule” and “Reactive Power schedule,” but only voltage schedule is used in

Requirement R1. He also asked if the Reliability Coordinator (RC) needs to be involved relative to coordination between TOP Areas and/or impact to System Operating Limits (SOL) and Interconnection Reliability Operating Limits (IROL) beyond a single TOP Area. For example, if a voltage schedule gets communicated to the RC on a 30-day basis, upon request (assuming it's used in the determination of IROLs), how does the voltage schedule get integrated into the determination of an IROL in Real-time or day-ahead? The two VAR standards seem silent on this component. This should be discussed for the benefit of industry.

Last, D. Sauriol commented that there is no timing provided by the TOP for being outside the voltage schedule (i.e., excursion). The notification requirements in Requirement R5, Part 5.2 should include the timeliness of the notification. Providing the information to GOP is inconsistent, including the potential for reoccurrence. How long may the GOP be outside the schedule before a notification? A. Mackellar concurred this is a problem for Exelon's power plants.

Continuing from the team's grading spreadsheet should the TOP be telling the GO what tap the generator step-up (GSU) transformer should to be on as required by VAR-001, Requirement R6? M. Cruz-Montes pointed out that PRC-019-2 - *Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection* may provide an example for how voltage and reactive changes may be coordinated between the TOP and GO. He further suggested this requirement could be enhanced to improve when the requirement initiates and not rely on the initial interconnection agreements. For example, required tap changes to the GSU transformer following a TOP study. Requirement R6 also does not address cases where the TO may be the owner of the GSU transformer. Hydro-Québec provided additional support since the TO and GO ownership of the GSU transformer is accounted for in FAC-008-3, Requirement R1. This concern may need be addressed in any future VAR standard revisions. Comments from Hydro-Québec pointed out that the requirement is not results-based. It specifies the means rather than the outcome or result. Additionally, the term "necessary" seems irrelevant.

<u>VAR-002</u>

The team continued discussing the grading comments for VAR-002-4.1, beginning with Requirement R1. A question came up about whether there should be requirements around the commissioning and tuning of the power system stabilizer (PSS). The team may need to address voltage regulators or automatic voltage regulators (AVR) that have an integrated PSS. The team may need to ask industry if it is clear that a PSS can be standalone or integrated into an AVR. M. Scott noted that Requirement R4 in VAR-002 addresses dispersed generation resources (DGR); however, in Requirement R1 may unintentionally capture DGR (i.e., each unit) where the intent needs/could to be at the site level because there may be times when not every unit would be in voltage control mode.

In VAR-002 Requirement R2, should there be some sort of exemption for following schedule during startup and shutdown? Also, in Requirement R2, Part 2.1 DGR may not have an alternate means of controlling voltage. If not available, the failure of the AVR should not result in a violation. The DGR owner may need a provision for notifying the TOP as an improvement to the standard.

Questions were raised about Requirement R2, Part 2.2 concerning instruction from the TOP to the GOP to modify a voltage schedule and may be redundant with TOP-001-3, Requirement R1 requiring the TOP to issue Operating Instructions to maintain reliability. Requirement R2, Part 2.3 whether the voltage point of measurement is a necessary requirement. The reliability benefit is not clear and may need additional industry input. Also, the clause "specified by the Transmission Operator" is unnecessary and may be confusing.

On VAR-002 Requirement R3, A. Chua noted that the notification time intervals should be determined by the local TOP and not a requirement unless there is a technical justification for 30 minutes. A. Mackellar added that the timeframe could be dependent on the size of a plant and its location in the interconnection. S. Solis surmised that the timeframe is based upon the Real-time Assessments that are performed on at least a 30 minutes basis by the TOP and RC in TOP-001-3, Requirement R13 and IRO-008-2, Requirement R4, respectively. S. Barfield noted that the standard drafting team working on Project 2007-06.2 argued that the maximum timeframe to direct actions to maintain reliability would be limited to an hour. A maximum of an hour is due to having the data refreshed on at least a 30 minute basis for the Real-time Assessment (RTA) and is consistent with the rationale provided by S. Solis. Also, S. Barfield highlighted that the data specifications that provide inputs to the RTA and Operations Planning Analysis (OPA) in TOP-003-3 and IRO-010-2 only requires the TOP and RC to specify data required to perform the RTA and OPA and not at all generating plants, unless the input is necessary. A. Mackellar suggested that VAR-002 Requirement R3 could be clearer if it noted that the requirement could be met through telemetry. The team may need to look at the requirement from an exception standpoint. For example, if the status change is telemetered (i.e., through TOP-003-3 or IRO-010-2), then the notification would be required by exception. S. Solis added that the RC may need notification of status change as well, but from the TOP and not the GOP. This would align with the idea or concept that the data specification would be a vehicle for notification and that Requirement R3 would become a notification by exception.

VAR-002 Requirement R4 may need clarification that a full "D" Curve is not required when reactive capability is affected. S. Solis added that the RC may need notification of status change in reactive capability as well, but from the TOP and not the GOP. This would align with the idea or concept noted above for Requirement R3. S. Solis noted that reactive capability is based on the "D" Curve, which is a snapshot of the capability; therefore, the notification component should be clear that it is for degradation and not additional capability due to other factors. Additionally, this requirement may need to consider an exception for reporting reactive capability changes or alternative means that may be handled by other standards. K. Harrison added that he did not believe the circumstances would occur very often, therefore, should remain a direct notification.

VAR-002 Requirement R5 is a data flow requirement from the GOP to the TOP. There are similar requirements in MOD-032-1 *Data for Power System Modeling and Analysis*; however, those data transmittal requirements are to the Transmission Planners (TP) and Planning Coordinators (PC), not the TOP. S. Phan provided additional context to the feedback provided by Hydro-Québec from the team's earlier assignment to review the standard using the grading process. In Canada, most

GSU transformers are owned by the Transmission Owner (TO) and the standard is silent on how the TO would provide that data upon request. The concern may impact VAR-001 as well. The time horizon is "Real-time Operations" and is not reflective of the longer 30-day period to comply with the performance. The time horizon probably should be "Operations Planning."

VAR-002 Requirement R6 "equipment rating" is a NERC defined term and may need capitalizing. Reliability Standard IRO-001-4 uses only "equipment" in this context, for example, and also may need to be further evaluated for relevance. The Time Horizon should be "Operations Planning" and/or "Near-term Planning" and not "Real-time Operations." It may take up to a year for the GO to make adjustments and therefore cannot be done in real-time.

3. **Review of VAR Reliability Standards**

   a. VAR-001-4.1 – Voltage and Reactive Control
      The team re-reviewed the Requirements and Measures more thoroughly. VAR-001, Requirement R1 should include clarifiers that "adjacent" means those entities that are synchronously connected (e.g., see COM-001-2). Measure M1 does not use "calendar" like the requirement. Measure M2 uses "resources based on their assessments of the system" as a measure for performance not mandated by the requirement; however, this raises the question whether there was intent to require an assessment. Further, the measure falls short on the conditions for which sufficient reserves are required. Measure M3 has "may include," but not the full phrase "may include, but is not limited to…" For Requirement R4, there may need to include exemption criteria to perform a re-evaluation of the exemption on a periodic basis. Also, there may be a need for the TOP or GOP to raise concerns (i.e., notification, feedback) where they are having issues meeting the voltage schedule. Measure M5 does not address whether the target value or range is based on the low-side or high-side of the GSU transformer. Is this important? Requirement R5, Part 5.3 is not consistent with R1 in using "calendar" with calendar days. Measure M6 appears to imply the consultation is a performance of the requirement. Also, Measure M6 should be made consistency with the structure of Requirement M1 (i.e., "including, but not limited to…").

   b. VAR-002-4 – Generator Operation for Maintaining Network Voltage Schedules
      The team did not discuss VAR-002 in greater detail at this meeting and may take it up during a later meeting or call.

4. **Roundtable Discussions**

   a. Voltage schedules in general
      Beginning the discussion with TOP entities, B. Harm gave an overview of the Optimal Voltage Control program that PJM is working toward. The group discussed the potential for changes in the way the VAR standards would be complied with. Members did not see any particular issues with the current standards as written; however, cautioned that if revisions were made in response to the enhanced periodic review that drafting team members should consider the potential for voltage schedules becoming dynamic as opposed to the schedules, that for the

most part, are traditionally static in nature. Currently, the VAR standards appear to provide this flexibility.

S. Solis provided detail on how ERCOT as a TOP communicates schedules and noted that ERCOT is exploring dynamic voltage schedules as well. K. Harrison provided ITC's background on schedules noting that ITC treats "system" and "generator" voltages schedules differently. System schedules are applicable only at the buses. Reactive Power schedules are generally limited to older generator units. The system voltage schedule traditionally is set the same across all buses and are essentially the "system voltage limits" that ITC uses. D. Sauriol also noted that AEP uses the same voltage schedule and limit philosophy as ITC.

The discussion turned to how GOPs address voltage schedules. A. Mackellar noted that structural changes have occurred over the years. For example, PJM provided the monitoring points at the high-side of the GSU transformer and now Exelon has taken over the monitoring under their voltage programs. Within the New York Independent System Operator (NYISO) footprint, Exelon receives a voltage schedule for most plants except for one plant.

b. Reactive reserves (e.g., for small units that are operating at the upper end of the reactive out to meet the voltage schedule). Is this good for reliability?
   B. Harm provided an overview of the *Reliability Guideline, Reactive Power Planning and Operations* (June 2016 Draft) document. S. Solis used the Reactive Reserves section of the document to initiate discussion about reserves. He further raised the concern that with new market entrants (e.g., GOP and TOP) relying strictly on Reliability Standards and may not have a wealth of good industry practice. The team should think about how the VAR standards encapsulate the operation of the bulk-power system with respect to monitoring reactive reserves. This is especially important as the resource mix changes (i.e., resources with less reactive capability) into the future.

5. **Future meeting(s)**
   Tentatively set for the week of October 24, 2016.

6. **Adjourn**
   The meeting adjourned at 11:46 p.m. Eastern on Friday, September 9, 2016.