PNNL-36516

Transmission Operator Workflows for Real-Time Reliability Studies

A Review of Control Room Practices and Naturalistic Decision Making

August 2024

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Prepared for the U.S. Department of Energy
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Richland, Washington 99354

Summary

This report provides an overview of real-time reliability study tools and their use by power system operators in the control room environment. After introducing some of the nuances of the control room environment and the differences in perspectives between power system engineers and operators, the roles and responsibilities of key entities involved in RTCA workflows are introduced. These are specifically the transmission system operator (TOP) and reliability coordinator (RC), which are required to run tools such as real-time contingency analysis (RTCA) as part of a real-time reliability assessment every 30 minutes, as dictated by a series of standards issued by the North American Electric Reliability Corporation (NERC).

The process by which power systems operators operate the grid is discussed in terms of naturalistic decision making (NDM) and the recognition-primed decision-making (RPD) model. This cognitive model describe how experts working in high-risk, high-stress environments make safety-critical decisions under uncertainty and time pressure. For power system operators, the mental simulations involved in the traditional RPD model are supplemented by physics-based simulations using numerical tools, such as RTCA, to improve situational awareness and effectiveness of control actions.

Next, a generic workflow is introduced to describe operator decision making for running RTCA tools and responding to system violations on a pre-contingent basis. The types of analysis performed and control actions chosen by power system operators are described in detail. The overall high-level workflow is then expanded in subsequent sections, with special attention given to high-voltage violations, low-voltage violations, and thermal overloads. Each type of violation is described in detail, with explanations of common causes, impacts on equipment and customers, and mitigation strategies. An additional workflow diagram is provided for each type of violation.

Acknowledgments

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Acronyms and Abbreviations

AGC	Automatic Generation Control
AI	Artificial Intelligence
AOR	Area of Responsibility
AVR	Automatic Voltage Regulation
BA	Balancing Authority
BES	Bulk Electric System
CA	Contingency Analysis
DER	Distributed Energy Resource
EHV	Extra High Voltage
EMS	Energy Management System
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FIDVR	Fault-Induced Delayed Voltage Recovery
IROL	Interconnection Reliability Operation Limit
ISO	Independent System Operator
LODF	Load Outage Distribution Factor
ML	Machine Learning
NDM	Naturalistic Decision Making
NERC	North American Electricity Reliability Corporation
PSSE	Siemens Power System Simulator for Engineering software
PTDF	Power Transfer Distribution Factor
RAS	Remedial Action Scheme
RC	Reliability Coordinator
RPD	Recognition-Primed Decision-making
RTCA	Real-time Contingency Analysis
SCADA	Supervisory Control and Data Acquisition
SA	Situational Awareness
SE	State Estimation
SOL	System Operating Limit
SVC	Static VAr Compensator
TSA	Transient Stability Analysis
TOP	Transmission System Operator
TSO	Transmission System Operator
VSA	Voltage Stability Assessment

Contents

1.0 Introduction

The operations control room at electric utilities is a high-risk, high-stress, high-tasking environment in which power system operators (sometimes referred to as grid dispatchers) are responsible for real-time operation and control of the bulk electric system (BES). Although a small amount of automation exists through feedback control systems, such as automatic generation control (AGC), most control actions are performed by human operators coordinating via three-way verbal communication with field crews and operators at other control centers. An example of a typical mid-size transmission control room is shown in Figure 1.

Control of remote field equipment is performed either through a supervisory control and data acquisition (SCADA) system or manually by field crews (who drive a truck to a remote location and then “turn the crank” to close switches or adjust equipment). The SCADA is system is supplemented with advanced power applications to form an Energy Management System (EMS) for transmission control rooms. The EMS software typically includes a suite of advanced power applications, such as state estimator (SE), contingency analysis (CA), voltage stability analysis (VSA), and transient stability analysis (TSA).

This report will focus on the use of real-time contingency analysis (RTCA) by power system operators as one of the key tools for reliability coordination and ensuring reliable operation of the bulk transmission grid.

Figure 1: Control room at a mid-sized transmission system operator (TSO), taken from [40].

1.1 Functional Entities Involved in Contingency Analysis

Due to the extreme complexity and hundreds of individual job tasks involved in real-time operation of the electric grid, the job of operating the bulk grid is divided among multiple categories of entities. The responsibilities of each entity are defined in detail by the North American Electric Reliability Corporation (NERC), which is responsible for overseeing day-to-day regulatory compliance. The responsibilities of each entity are described in extreme detail by the NERC reliability standards [1]. Reliability Coordinators (RC) have the highest level of authority and are responsible for reliable operation of an entire geographical region and possibly an entire grid interconnection. There are a total of 18 RC in North America. Each RC is also typically responsible for overseeing multiple Transmission Operators (TOP) and Balancing Authorities (BA). The primary function of the RC is providing situational awareness and real-time monitoring because only the Reliability Coordinator has sufficient perspective/vision necessary to act in the interest of wide-area reliability.

The RC is also responsible for establishing and monitoring Interconnection Reliability Operating Limits (IROL), which if violated, can lead to instability, uncontrolled separation, or cascading outages that will adversely impact the reliability of the bulk electric system. IROLs are determined through system planning studies examining voltage stability limits and angle stability limits for a wide range of operating conditions. Violations of IROLs must be resolved within 15 minutes using emergency control actions, up to and including load shedding (informally known as a rolling blackout). Day-ahead and real-time contingency analysis is one of key tools used by the RC to ensure the reliability of the overall region. The RC coordinates outages and reviews operations plans of TOPs and BAs on daily basis and perform next day studies using contingency analysis, voltage stability analysis (VSA), and transient stability analysis (TSA). The RC can deny or delay request for any outage if consequences can adversely affect reliability of the grid.

The Transmission Operator is responsible for operation of transmission facilities and equipment within high-voltage substations to maintain the reliability of the bulk electric system. This includes switching operations for lines, transformers, and shunt equipment (capacitors and reactors) to maintain system voltage within predefined voltage schedules. There are a total of 180 TOPs in North America. The TOP is also responsible for defining System Operating Limits (SOLs), probable contingencies, and operating procedures for normal, abnormal, and emergency conditions. SOLs are typically defined based on the high/low voltage limits of equipment, thermal limits of transmission lines, thermal limits of transformers, etc. Violations of SOLs will result in tripping of equipment by protective relays. If one piece of equipment trips due to thermal overload, the resulting power flow will need to be carried by other lines and transformers, which in turn may become overloaded and trip. This can lead to a cascading outage and regional blackout.

In real-time, the TOP is responsible for monitoring the grid and keeping the system under all relevant SOLs and IROLs. Because the RC is the only entity with a complete view of the region and reliability problems that one entity may be causing in a neighboring area, the TOP must coordinate closely and comply with all directives from the RC. TOP also has obligation to perform a real-time reliability assessment (RTA) every 30 minutes, although in practice, this assessment is performed every 5 minutes. This provides sufficient time so that if one of the software applications used to perform the RTA fails to solve, the TOP has sufficient time to fix the model and complete the assessment before the reporting time window lapses.

1.2 Operator Naturalistic Decision Making

Unlike power systems engineers (who often have advanced university degrees and strong backgrounds in mathematical modeling and physic-based simulation), power system operators in the United States generally come from a field work background, with experience as either a lineman / substation crew or as a nuclear reactor / shipboard power operator aboard military submarines and aircraft carriers. As a result, power system operators have substantially different technical perspectives and decision-making processes than power systems engineers, as documented extensively by [2]. A comparison of such perspectives is illustrated in Table 1.

Table 1: Comparison of Perspectives between Power Systems Engineers and Operators

Dimension	Engineering Perspective	Operator Perspective
Cognitive approach	Abstract, analytical, formal, deterministic.	Physical, holistic, empirical, fuzzy.
Areas of emphasis	Efficiency, optimization, algorithmic results & performance	Safety, situational awareness, rapid response to real-time events.
Approach to managing operating cost	Minimize economic cost / locational marginal price, and max customer satisfaction.	Maintain bulk reliability regardless of economic cost.
Approach to customer reliability	System average interruption frequency index (SAIFI) / System average interruption duration index (SAIDI) metrics	Customer load is just a tool. Shed load as need to maintain bulk reliability.
Approach to equipment modeling	All components of same rating are modeled, treated identically	Each component unique – sound, vibration, temperature, crank handle resistance, etc.
Approach to new tools	Appreciate innovation, novelty, and cutting-edge technologies / algorithms	Skeptical of new technology. Require extreme consistency, availability, reliability, accuracy.
Approach to decision-making	Decisions based on precise numerical results and optimality	Decisions based on past experience, operating procedures, verbal communication with other humans.

As a result of these differences, researchers developed a fundamentally different approach to understanding operator decision-making and control room workflows called Naturalistic Decision Making (NDM). NDM research seeks to understanding how humans make decisions in real-world settings characterized by complexity, uncertainty, and time pressure [3]. The NDM framework was created by a group of about 30 behavioral scientists in 1989 who gathered for a conference sponsored by the Army Research Institute [4]. This framework identified five essential characteristics of expert decision making in real-world settings: proficient decision makers, situation-action matching decision rules, context-bound informal modeling, process orientation, and empirical-based prescription.

A central model within NDM is the Recognition-Primed Decision-making (RPD) model, which was first developed by Gary Klein to describe the decision making processes of firefighters [5]. This model observes that experienced decision-makers use their extensive knowledge and past experiences to recognize patterns and quickly identify plausible courses of action. When faced with a new situation, they compare it to previous ones stored in their memory, allowing them to rapidly assess the situation and determine a likely successful response. Rather than evaluating multiple alternatives simultaneously, as traditional decision models often suggest, individuals using RPD generate one option at a time based on their intuition and prior knowledge. The decision-maker then performs a mental simulation to determine if that choice would lead to the correct outcomes. If the first option seems insufficient, they move on to another, repeating the process until they find a satisfactory solution.

This model was subsequently extended by the work of Frank Greitzer and Robin Podmore [6], [7] to examine the decision processes used by operators for assessing operator tool usage [8], [9], [10] and creating effective training [11]. Within this framework, it was observed that power system operators heavily rely on computer-based simulations using EMS tools (such as real-time contingency analysis) to supplement their mental simulations. Power system operators follow a cycle (shown in Figure 2), in which they assess a situation using cues from assistant tools. These cues trigger story patterns of prior events, which they return to their tools to validate. Once validated the story patterns inform a set of actions intended to mitigate the situation.

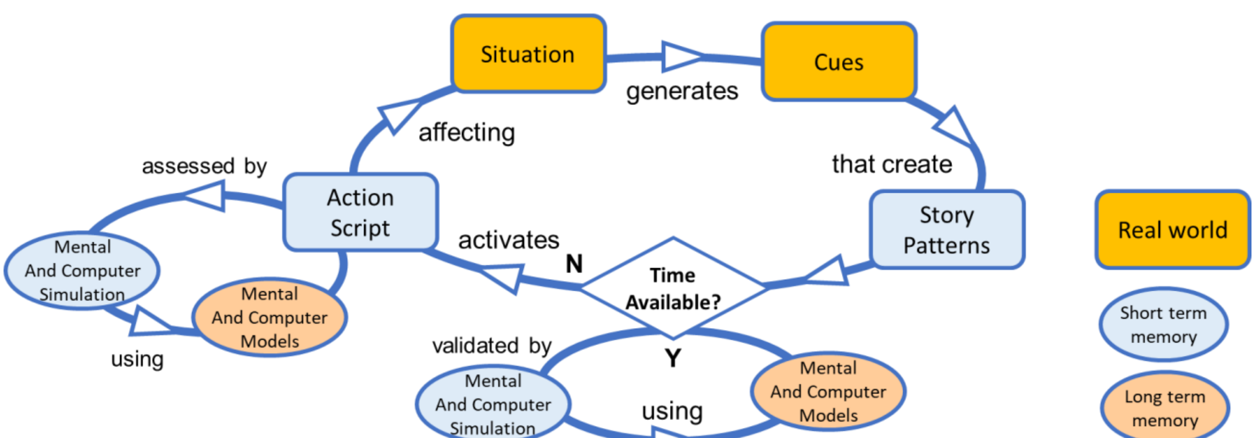


Figure 2: An adaptation of the recognition-primed decision model used by power system operators for real-time operations, adapted from [11].

The **Situation** refers to the current state of the bulk power system, which will vary based on a wide range of factors, such as time of day, season, weather conditions, outaged equipment, and power flows between various areas within the transmission grid.

The **Cues** used by operators are derived from the information presented to operators, including SCADA displays, alarms logs, contingency analysis summaries, charts, maps, and wallboard displays. In the Area of Responsibility (AOR) of a small to mid-sized TOP, there are thousands of measurements collected from field equipment every few seconds, so effective display of this information is critical to building operator situational awareness (SA). An example of a summary display with the status of real-time EMS applications is shown in Figure 3.

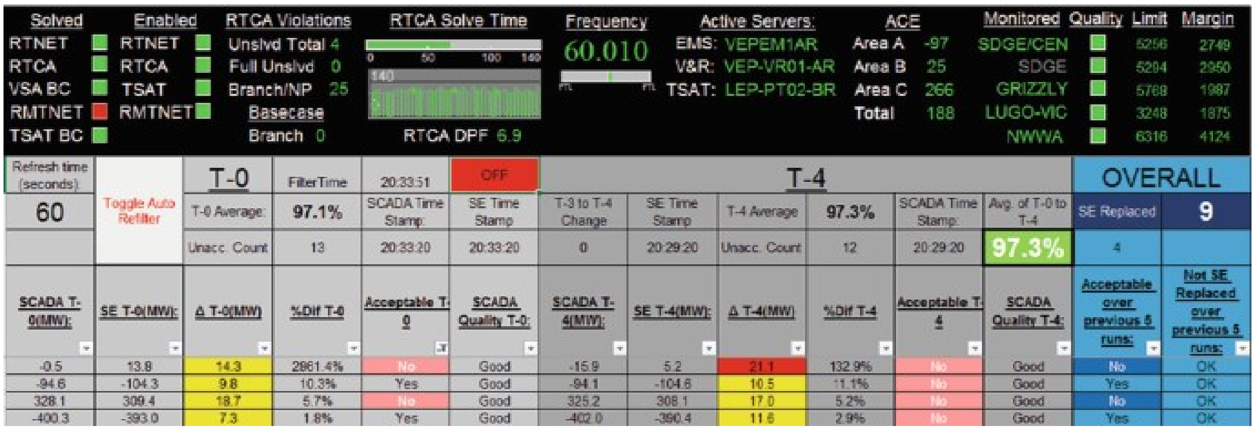


Figure 3: A summary display of the status of real-time reliability tools such as RTCA in the control room, taken from [15].

Power system operators then use a limited number of recognizable patterns guiding decision making to create a **Story Pattern**. The story is informed by the three levels of SA based on the perception of elements in the environment, the comprehension of their meaning and the anticipation of what will happen [12]. Figure 4 illustrates the stages of perception, comprehension, and projection from the perspective of a power system operator. The story pattern is informed by binary equipment statuses, anticipated values for current conditions, conflicting data (equipment malfunction vs bad data), alarms received (or lack of such), and system behavior during normal, alert, and emergency conditions.

Once the power system operator has built a full story pattern, they will seek to validate their projection of the future system status through a combination of mental and computer-based **Simulations**. For most system conditions, the operator can run a mental simulation based on validation of system conditions against their established cognitive model and what-if scenarios. As the operator scans their EMS displays, they constantly validate the information displayed against simple rules of thumb, such as “I see zero power flow this line, which means the breaker is open; is it actually open?” or “Is the total MW flow into the bus equal to the flow out of the bus?”. The experienced operator can usually estimate the qualitative impact on the system for any given control action. For example, an operator will know intuitively that switching in a capacitor

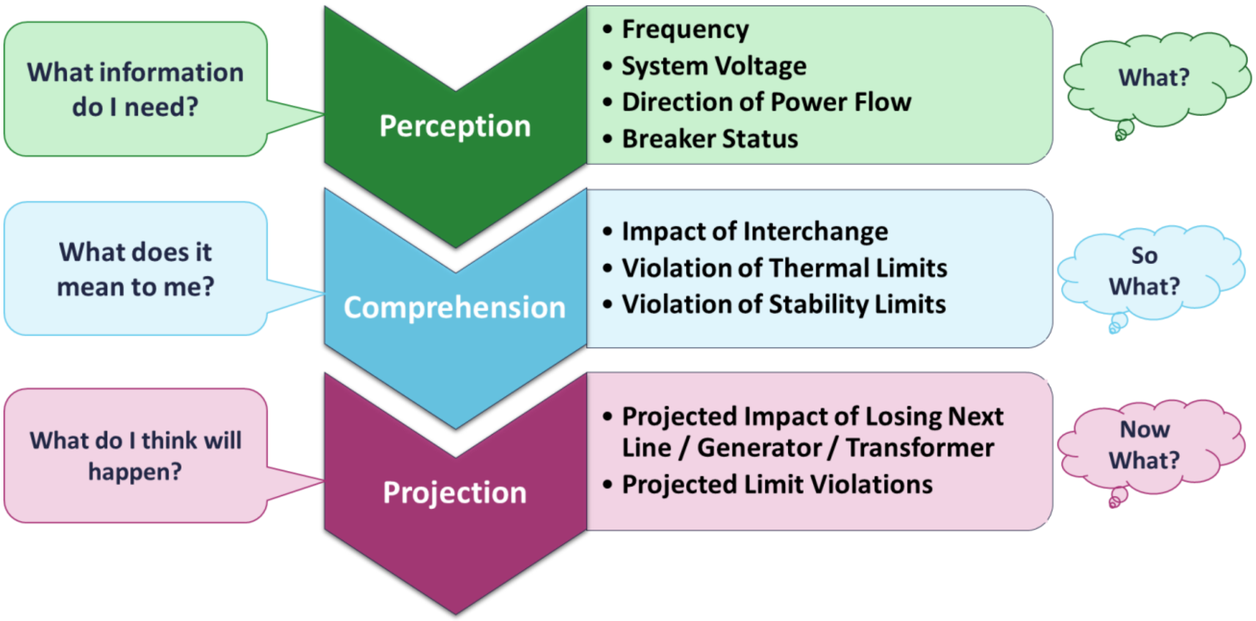


Figure 4: Situational awareness, as divided into stages of perception, comprehension, and projection with related power system parameters used by control room operators.

will increase local bus voltages, whereas switching in a reactor will decrease local bus voltages. However, estimating the quantitative effects of control actions when the system is in an unusual operating condition can be very difficult. This need illustrates why availability of accurate numerical analysis tools in the control room is so important.

In Figure 5, the operator will observe that line Seattle-Renton #3 is out of service, as illustrated by the white color in the EMS display. The operator can also tell that lines #1 and #2 are near their 70% thermal limit, as indicated by the thickness of the green bar. The operator can then run a what-if scenario in their head, where they imagine what would happen if either line was suddenly lost. In this case the remaining line would need to carry the load of both lines, which would 70% + 70% = 140% of the limit of the line. This scenario is a large SOL violation. The operator would then realize that the remaining line would immediately trip out, which could turn into a cascading outage and blackout.

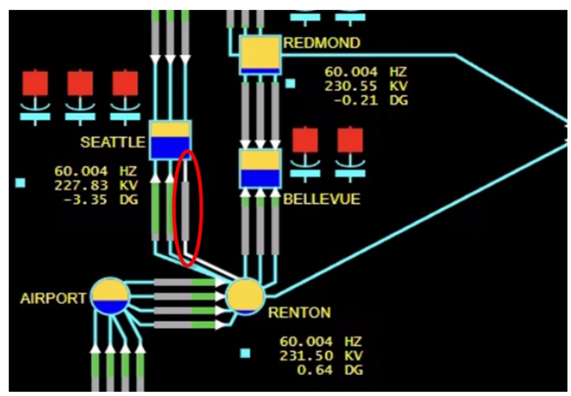


Figure 5: Sample EMS display on the Cascadia synthetic model.

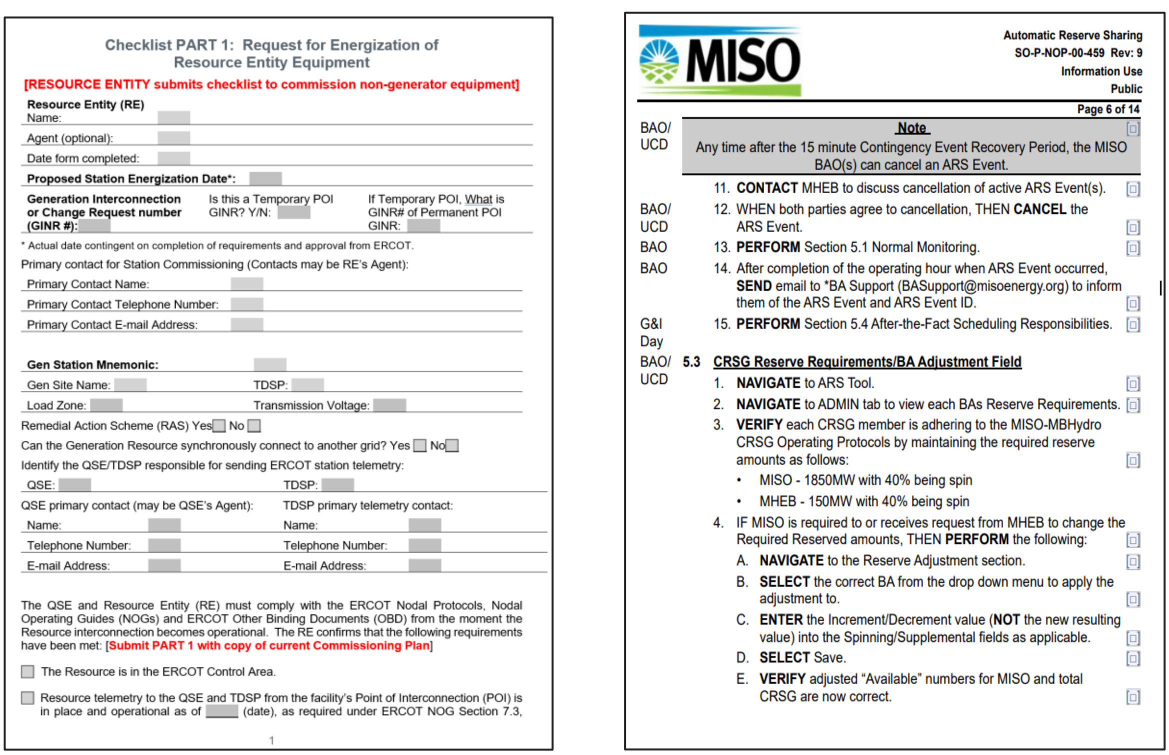
This mental simulation can be validated by checking the RTCA display, shown in Figure 6. RTCA validation would reveal that the given contingency would actually cause a 34.8% overload of the line (which is close to the 40% mental estimate). The operator would then proceed to take remedial control action to mitigate the SOL violation.

Contingency	Contingenc	Violation	Type	Overload (% abs)	Units
SEATTLE - RENTON SEA_RENT 2	Line	SEATTLE - RENTON SEA_RENT 1	Overload	34.82	MVA
SEATTLE - RENTON SEA_RENT 1	Line	SEATTLE - RENTON SEA_RENT 2	Overload	34.82	MVA

Figure 6: RTCA display window for two line contingencies on the Cascadia synthetic model.

Finally, the operator will develop an **Action Script** with a series of sequential actions that they will take to address the situation. The choice of control action is dictated by the operator's decision workflow and written operating procedures. Detailed decision trees for common contingency violations are presented within this report. Operators also rely heavily on structured checklists for both the most common and most complicated tasks, such as shift turnover, pre-defined IROL violations, and black start restoration. Examples of planning and operations checklists from the Electricity Reliability Council of Texas (ERCOT) and Midwest Independent System Operator (MISO) are shown in Figure 7.

If there is sufficient time and appropriate study tools are available, the operator may validate their planned action script through further simulations of the grid. This validation is typically performed by saving a snapshot of the entire transmission grid at the given time (i.e., EMS basecase), and then loading that model into an offline study tool for further simulations and what-if studies.



Checklist PART 1: Request for Energization of Resource Entity Equipment

[RESOURCE ENTITY submits checklist to commission non-generator equipment]

Resource Entity (RE) Name:

Agent (optional):

Date form completed:

Proposed Station Energization Date*:

Generation Interconnection or Change Request number (GINR #): Is this a Temporary POI GINR? Y/N: If Temporary POI, What is GINR# of Permanent POI GINR:

* Actual date contingent on completion of requirements and approval from ERCOT.

Primary contact for Station Commissioning (Contacts may be RE's Agent):

Primary Contact Name:

Primary Contact Telephone Number:

Primary Contact E-mail Address:

Gen Station Mnemonic:

Gen Site Name: TDSP:

Load Zone: Transmission Voltage:

Remedial Action Scheme (RAS) Yes No

Can the Generation Resource synchronously connect to another grid? Yes No

Identify the QSE/TDSP responsible for sending ERCOT station telemetry:

QSE: TDSP:

QSE primary contact (may be QSE's Agent): TDSP primary telemetry contact:

Name: Name:

Telephone Number: Telephone Number:

E-mail Address: E-mail Address:

The QSE and Resource Entity (RE) must comply with the ERCOT Nodal Protocols, Nodal Operating Guides (NOGs) and ERCOT Other Binding Documents (OBD) from the moment the Resource interconnection becomes operational. The RE confirms that the following requirements have been met: [Submit PART 1 with copy of current Commissioning Plan]

The Resource is in the ERCOT Control Area.

Resource telemetry to the QSE and TDSP from the facility's Point of Interconnection (POI) is in place and operational as of (date), as required under ERCOT NOG Section 7.3,

1

MISO

Automatic Reserve Sharing
SO-P-NOP-00-459 Rev: 9
Information Use
Public
Page 6 of 14

BAO/ UCD **Note**
Any time after the 15 minute Contingency Event Recovery Period, the MISO BAO(s) can cancel an ARS Event.

11. **CONTACT** MHEB to discuss cancellation of active ARS Event(s).

BAO/ UCD 12. WHEN both parties agree to cancellation, THEN **CANCEL** the ARS Event.

BAO 13. **PERFORM** Section 5.1 Normal Monitoring.

BAO 14. After completion of the operating hour when ARS Event occurred, **SEND** email to *BA Support (BASupport@misoenergy.org) to inform them of the ARS Event and ARS Event ID.

G&I Day 15. **PERFORM** Section 5.4 After-the-Fact Scheduling Responsibilities.

BAO/ UCD **5.3 CRSG Reserve Requirements/BA Adjustment Field**

1. **NAVIGATE** to ARS Tool.
2. **NAVIGATE** to ADMIN tab to view each BAs Reserve Requirements.
3. **VERIFY** each CRSG member is adhering to the MISO-MBHydro CRSG Operating Protocols by maintaining the required reserve amounts as follows:
   - MISO - 1850MW with 40% being spin
   - MHEB - 150MW with 40% being spin
4. IF MISO is required to or receives request from MHEB to change the Required Reserved amounts, THEN **PERFORM** the following:
   A. **NAVIGATE** to the Reserve Adjustment section.
   B. **SELECT** the correct BA from the drop down menu to apply the adjustment to.
   C. **ENTER** the Increment/Decrement value (**NOT** the new resulting value) into the Spinning/Supplemental fields as applicable.
   D. **SELECT** Save.
   E. **VERIFY** adjusted "Available" numbers for MISO and total CRSG are now correct.

Figure 7: Sample publicly available operations checklists from ERCOT [42] and MISO [43].

2.0 Real-Time Contingency Analysis

2.1 RTCA Tools and Classification of Contingencies

As a result of the Northeast 2003 Blackout, a series of transmission operations standards were developed to help ensure the reliability of the bulk power grid. NERC Standards TOP-001-5 [13] and IRO-008-2 [14] require that each TOP and RC conduct a real-time reliability assessment every thirty minutes to ensure that no current or anticipated operating state results SOL or IROL violations. In practice, most utilities perform assessments every five minutes using a combination of power flow, contingency analysis, and VSA / TSA stability tools.

RTCA is the primary tool for monitoring expected post-contingency operating conditions and identifying unacceptable system performance. A contingency is defined a loss of any given transmission line, transformer, generator, or circuit breaker. In practice, this is reduced only to equipment with a nominal voltage rating greater than 99 kV and generators with a nameplate capacity of at least 50 MW [15]. A complete list of all individual equipment that can be lost at a given time is compiled to form the "$n-1$" set of contingency definitions, along with all credible $n-2$ contingencies (such as two transmission lines on the same tower). The contingency analysis study is then performed by solving a power flow study with each consecutive outaged element removed from the system. If the study is solved using an exported EMS basecase or a static planning model of the system, it is known as offline contingency analysis. If the study is solved using the full node-breaker model updated with real-time equipment values from the State Estimator, then it is known as real-time contingency analysis. The RTCA solution is used to rank the various contingencies to determine the next Most Severe Single Contingency (MSSC) for current existing system conditions. For generation contingencies, the MSSC is generally loss of the single largest generating unit in the system.

Reliable system operation requires that both the RC and all TOPs in the region be proficient in the use of RTCA and knowledgeable in analyzing the results of the RTCA solution. For RTCA to run successfully, the State Estimator must have either a valid solution or a solution that solves with a mismatch that is accurate enough to allow the RTCA power flow to solve correctly. If the Base Case Solution power flow solves it will then process pre-defined contingencies and classified as "Unsolved", "Partially solved", "Harmful", "Potentially Harmful", Not Harmful", "Not Active" or "With Remedial Action Scheme". If the contingency is classified as a "Harmful" it means that limit violations will occur in the case that particular contingency happens. Harmful contingencies are displayed. A "Potentially Harmful" contingency is one that has detected that loading is at 95% of normal equipment ratings. A "Harmful" contingency means that loading is greater than 100% of the equipment ratings or the voltages have exceeded the limits set in SE.

Accurate results of RTCA depend on the accuracy of the model and having the correct topology of the system. The system model must be accurate and have all the correct impedances. It also must have correct switch status and generation values to give accurate results. To properly analyze RTCA solution results you must be aware of some of the limitations encountered in developing RTCA solution results. Contingencies should be defined in the EMS system by opening the correct breakers to de-energize the equipment. Some contingencies have Remedial Action Scheme (RAS) actions associated with them that need to be defined in the contingency. However, a discussion of RAS schemes is beyond the scope of this report.

In general, all control room CA tools are based on a static power flow solution with each outaged element removed, solved at 60 Hz system frequency. The approaches used can be categorized as either full AC power flow solutions or approximate methods [16]. Full AC power flow solutions sequentially apply each credible contingency to the power system and solve until convergence using a numerical method such as Newton-Raphson [17] or Fast-Decoupled power flow [18]. These methods provide detailed and precise analysis of the system under each contingency scenario at the cost of computational speed. In contrast, approximate methods typically use a Direct Current (DC) load flow approximation, which simplifies the analysis by neglecting reactive power flows in the system [19]. Another approximate method involves sensitivity metrics analysis, using Power Transfer Distribution Factors (PTDF) and Load Outage Distribution Factors (LODF) to estimate changes in system conditions without directly solving a power flow. These methods provide quicker, though less detailed, insights into the impact of various contingencies.

Some novel CA tools based on machine learning (ML) and artificial intelligence (AI) techniques have been proposed for a variety of use cases [20]. Possible uses of AI/ML include selection of credible contingencies, contingency clustering [21], contingency ranking [22], and estimation of post-contingent states [23]. Numerous AI techniques (surveyed by [20], [24]) have been proposed for contingency analysis, dating back to the 1970s [25]. The previous generation of older expert systems preferred decision trees and/or fuzzy logic, while newer ML techniques typically use neural networks and support vector machine methods. However, the ever-changing topology of the transmission grid presents a fundamental problem to creation of valid training for ML tools. As a result, few (if any) of these tools have been deployed in utility control rooms.

2.2 Limitations of Contingency Analysis

RTCA tools have many limitations that are often neglected or not completely understood. The first is that RTCA only uses a static power flow with contingent element(s) out of service. This inherently assume that passage from initial grid state to the final grid state is stable, which may not be a valid assumption. Loss of large generators or key tie-lines can result in large system oscillations, which can result in system separation or tripping of additional units. Furthermore, RTCA can verify only against pre-defined system operating limits; it cannot calculate new system limits as the system changes with varying real-time conditions. Finally, RTCA generally has limitations for cascading analysis, where equipment that would trip after occurrence of the given contingency is not removed from the solution.

Additionally, there are many Remedial Action Schemes (RAS) models that are triggered based on voltage and frequency threshold violation over certain time period. There are examples in operations when the voltage in steady state settles at above predefined threshold, so that the given RAS would not be activated in RTCA. However, in reality, the RAS would be triggered because the system voltage or frequency was below predefined threshold for specific amount of time.

In scenarios where the power system operates near its voltage stability limits, steady-state voltage stability analyses (VSA) needs to be used instead. These studies either solve for the P-V “nose curve” [26], [27] or apply newer sensitivity metrics [28], [29]. If the power system is operating close to its angle stability limits, transient stability analysis (TSA) tools must be used instead. These tools solve either a transient stability study or an electromechanical / electromagnetic timeseries simulation to determine the end-state of the power system after occurrence of the problematic contingency. TSA tools directly address the lack of dynamic and transient RAS modeling capability to simulate out of step relays, under/over-frequency tripping of generators, and time delay protective actions. Transient stability analysis can be used to solve contingencies that cause false alarms in RTCA and to arm remedial action schemes that can prevent angle instability [15]. Dynamic CA tools are far less commonly used due to their complexity, need for accurate dynamics models, and frequent dependence on high-performance-computing (HPC) systems [30], [31].

2.3 Relevant NERC Standards for Reliability Assessment

Below is a high-level summary of NERC standards that dictate the use of contingency analysis and real-time reliability assessments. It should be noted that the NERC standards are updated on a continual basis and the latest version of the standards [1] should be used at any given time.

- IRO-008-2: RC Operational Analysis and Real-Time Assessments
  - RC must perform day-ahead study to identify violations of any SOL and IROLs
  - RC must have operating plans to address SOLs and IROLs
  - RC must conduct real-time assessment every 30 min (note: in practice, most utilities do it every 5 min)
  - RC must notify TOP, BA of any SOL, IROL violations identified
- IRO-009-2: RC Actions for IROLS
  - RC must develop operating procedures for all IROLs to 1) prevent exceedance of IROL and 2) mitigate exceedance of IROL within the required time (usually 15 minutes)
  - If IROL exceeded, RC to direct TOP and BA to resolve IROL within required time
- IRO-002-7: Monitoring and Analysis
  - RC must collect real-time data needed to conduct reliability assessments.
  - RC approves planned outages of equipment and IT/OT maintenance downtime.
  - RC must identify IROLs and monitor status of facilities and RAS schemes.
- IRO-010-4: Data Collection
  - RC to maintain full set of data needed for ops planning, real-time monitoring, and real-time reliability assessments.
- IRO-018-1: Data Quality
  - RC must evaluate quality of data used in reliability assessments.
  - RC must evaluate quality of analysis results (convergence, accuracy, etc.).
- TOP-010-1: Real-time Reliability Monitoring
  - TOP must have operating procedures for monitoring the system and conducting reliability assessments.

2.4 Generic RTCA Workflow Diagram

Figure 8 below presents a generic workflow diagram [32] for performing RTCA studies in the control room as part of a real-time reliability assessment. The process starts with the TOP or RC operator running the RTCA tool in the EMS application suite. Start of a study run can be performed manually or automatically at a regular interval (typically every five minutes). As part of the RTCA run, the tool will study all credible $n-1$ and $n-2$ contingencies that have been entered in the system, including line outages, bus outages, transformer outages, and generator outages. The solution run may also include breaker faults and inadvertent breaker operations. For a large RC territory, such as the Western Interconnection in the US, this may total over 9000 contingencies that are individually solved at each solution run [15].

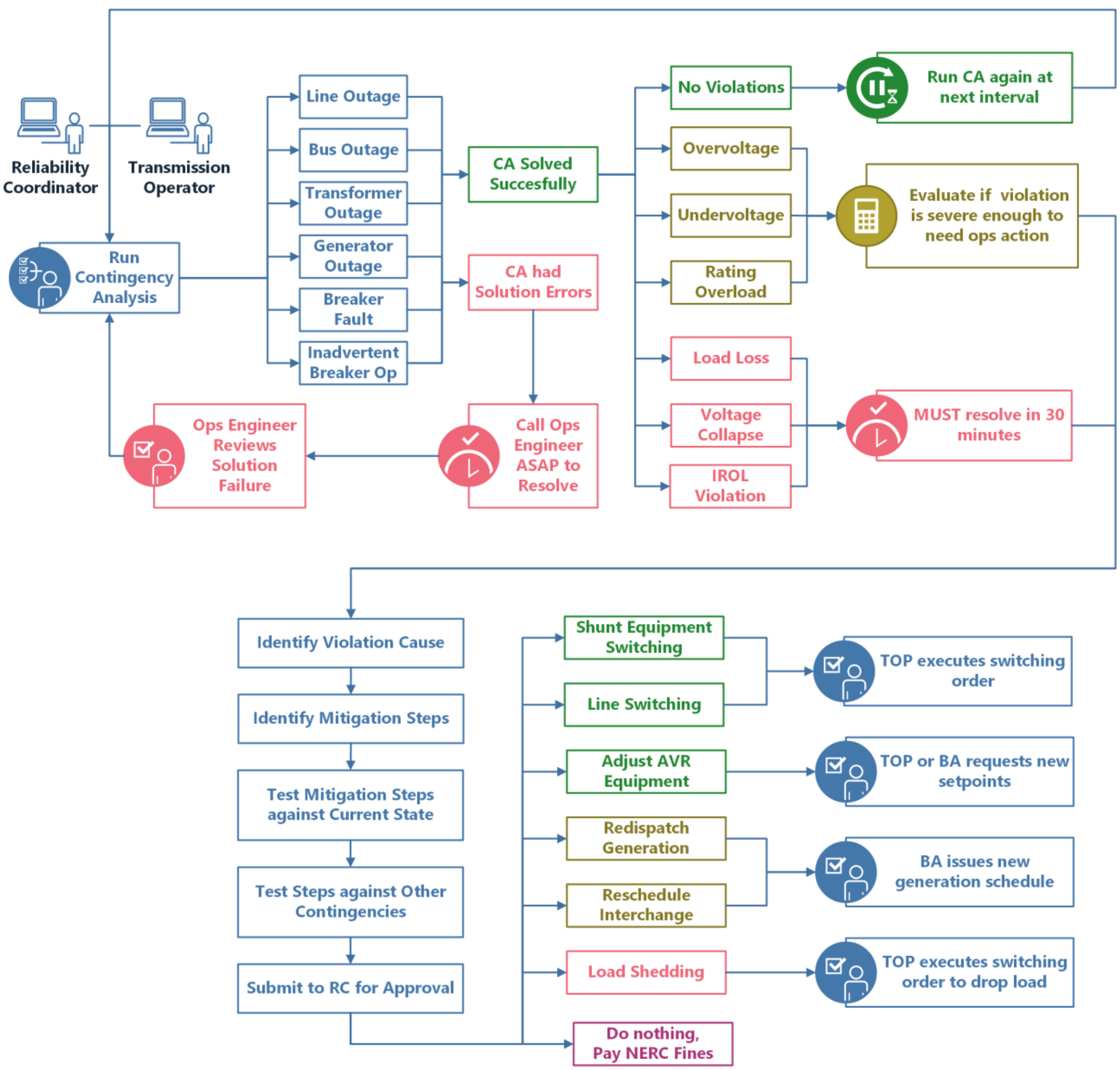


Figure 8: General workflow diagram for running RTCA and mitigating violations.

If the solution fails to converge, as shown in the red loop of Figure 8, the unsolved contingency is treated as a potential voltage collapse scenario and must be investigated along with any other harmful contingencies. In most cases, the power system operator will immediately call the Operations Engineer for assistance in determining whether the unsolved contingency is the result of a modeling error or will truly result in voltage collapse and system blackout.

If the CA solution solves successfully, the operator will then review the outputs to check if there were any post-contingent system violations. If the solution came back with no violations, no action by the operator is needed, and they will repeat the process from the beginning at the next solution iteration. If the solution does have violations, the RTCA tool will classify each violation. High-voltage violation, low-voltage violation, and thermal overload violation are less severe and will be evaluated by the operator to determine if remedial control action is required. If action is needed, the operator will perform a combination of mental and computer-based simulations following the decision trees shown in Sections 3.4, 4.4, 5.4, and 5.5 of this report. Contingencies that result in loss of load, voltage collapse, or IROL violations are treated as more severe and must be resolved within 15 to 30 minutes (depending on the type of violation). These types of violations tend to be system-specific and will be studied extensively in offline planning studies conducted by operations engineer and planning engineers. The results of these studies will then be formulated as written operating procedures that the transmission operator can execute as quickly as possible.

For all types of contingencies, the operator will generally follow a generic mitigation process that starts with identifying the cause of the violation, then formulating possible mitigation steps, testing those steps against the current system state, testing the steps against other contingencies, and then submitting the proposed set of control actions to the RC for review and approval [33]. The remedial actions that the operator can generally be grouped into three categories. The first category of control actions are non-cost actions. These actions do not incur any financial cost to the utility to implement and include switching of shunt capacitors or reactors, adjusting automatic voltage regulation (AVR) setpoints of generators, and switching transmission lines in or out of service. Operators will try to use these actions first to mitigate any RTCA violations. The second category of actions are off-cost actions, which typically involve re-dispatching or starting up / shutting down generating units. Because these actions take the system off the economically optimal operating point calculated by Economic Dispatch (ED) and Unit Commitment (UC) analyses, there is a direct financial cost to utility in taking these actions. Finally, if none of those actions resolve the contingency and it is severe enough to warrant emergency actions, operators can call for load shedding at critical locations in the system. Table 2 summarizes the actions that may be used.

Table 2: Summary of Possible Operator Control Actions to Mitigate RTCA Violations

Non-Cost Actions	Off-Cost Actions	Emergency Actions
Capacitor / reactor switching	Generation re-dispatch	Load shedding
Adjusting AVR setpoints	Generator startup/shutdown	
Line switching	Curtailment of renewables	
	Reschedule interchange	

3.0 Low-Voltage Violations

3.1 Common causes

Low-voltage violations in contingency analysis are generally associated with reactive power shortages caused by a combination of one or more factors, each of which are discussed in this section. The first is associated with long-term voltage instability, caused by heavy line loading and generating units exceeding their reactive capability curve. Figure 9 below depicts the typical reactive capability curve of a conventional synchronous generator, which represents the decrease in the ability of the unit to provide reactive power as the real power output of the unit increases. The capability curve of each unit is different and should be based on operating experience and unit testing. The ability of the unit to supply reactive power is limited by several factors including 1) rotor winding overheating, 2) field winding heating, 3) end turn heating, and 4) unit instability caused insufficient field strength [34].

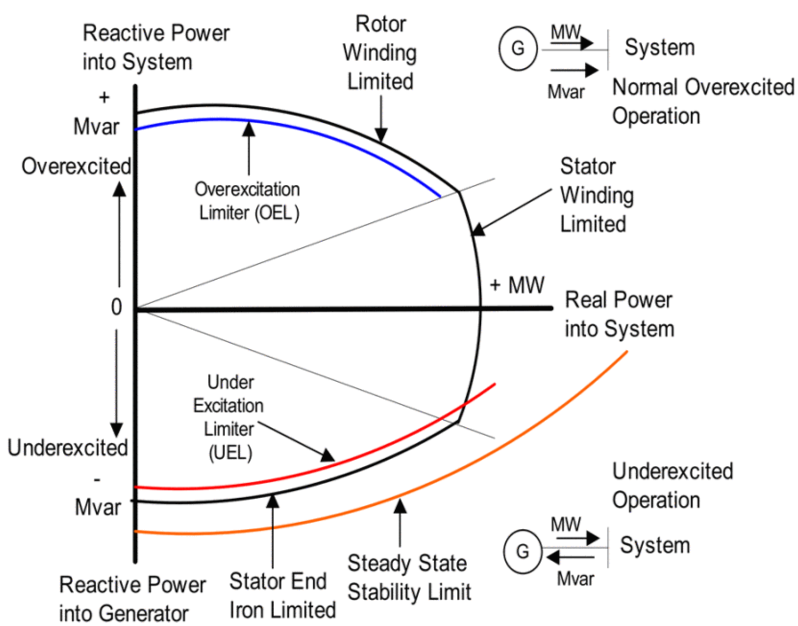


Figure 9: Typical reactive capability curve of conventional synchronous generators, taken from [44].

The behavior of conventional excitation systems, along with the need to maintain sufficient reactive reserves during real-time operations is well understood. However, inverter-based renewable generation units follow a capability curve bounded by 0.95 pf, as specified in FERC Order 827 [35] and as shown in Figure 10 below. It is worth noting that Order 827 also eliminated the previous exemption for wind generators to provide reactive power support.

Due to the much smaller range of reactive power output capability by non-synchronous generation, displacement of conventional units by renewables can lead to units reaching their reactive capability limits sooner, resulting in low-voltage violations. It may also cause a decrease in reactive reserves and higher risk of voltage collapse under operating conditions that previously did not contain any low voltage violations.

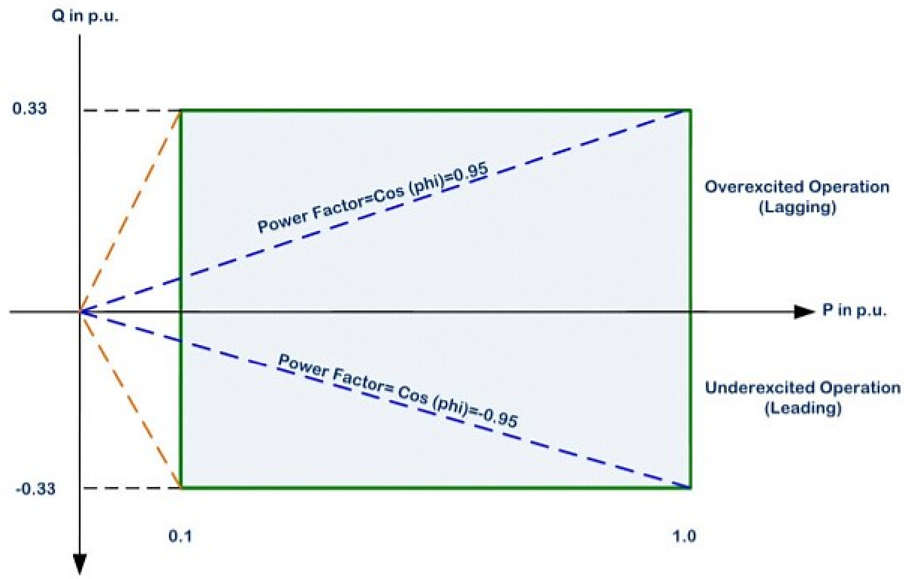


Figure 10: Typical reactive capability curve of non-synchronous generators, with 0.95 pf bounds on inverter-based resources.

The second common cause of low-voltage violations is associated with medium-term voltage instability and exceedance of the transfer limit of very long transmission paths. A rule-of-thumb used by power system operators for judging if the system is approaching voltage collapse is

- 500 MW over 500 miles (~800 km) of 500 kV line
- 300 MW over 300 miles (~500 km) of 345 kV line
- 200 MW over 200 miles (~300 km) of 230 kV line
- 100 MW over 100 miles (~150 km) of 115kV line

These guidelines are not a replacement for full voltage stability analysis. However, they provide a rapid tool for real-time assessment of low-voltage problems and proximity to voltage collapse.

A third related cause of low-voltage problems is heavy loading of the bulk transmission system, as described by the concept of Surge Impedance Loading. As can be seen from Figure 11, the reactive power consumption of a transmission line is a power function of the MW flow across the line. Under light loading, the line injects reactive power into the system, raising bus voltages. Under heavy loading, the line absorbs reactive power, lowering bus voltages. As lines approach their thermal limit, the associated reactive power consumption can quickly exceed the capability of nearby generators and lead to either localized or widespread low-voltage violations.

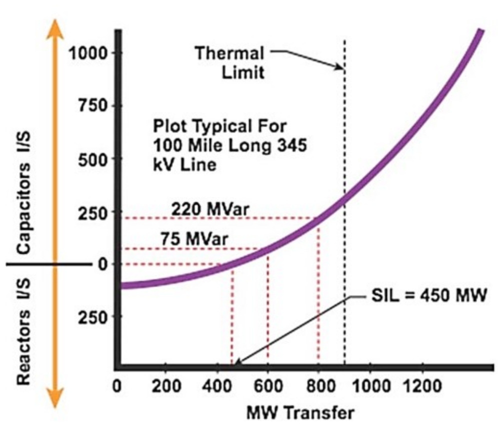


Figure 11: Surge impedance loading curve of a 345kV line, taken from [45].

A fourth related cause is insufficient reactive compensation of inductive loads with a low power factor. Load centers with large amounts of single-phase induction motor loads (such as refrigerators, air conditioners, etc.) often need capacitive compensation at both the distribution and sub-transmission level. Insufficient power factor compensation of feeders can result in depressed voltages at these load centers. Note that this is separate from the concept of short-term voltage instability and fault-induced delayed voltage recovery (FIDVR), which is caused by stalling of AC motors during a large fault on the transmission system.

The last common cause of low-voltage violations is mis-operation of voltage-control equipment. If transmission operators fail to switch out large line-reactors or bus-reactors and switch in shunt capacitors during high-load conditions, severe low-voltage conditions may result. Likewise, adjusting LTC transformer tap settings to raise voltage typically worsens voltage stability problems and may lead to voltage collapse. For this reason, most US utilities specify in their operating manuals and guidelines that transformer taps are not to be used to correct any low-voltage violations.

3.2 Impacts on equipment and customers

The impact of low-voltage violations on customers is typically not significant and is limited to low power quality and minor irritations, such as reduced light bulb brightness. However, low-voltage violations are an indication of bulk transmission voltage stability issues that may worsen into voltage collapse and system blackout.

An exception is industrial customers in the information technology sector. Data centers, semiconductor processing plants, and electronics assembly centers can be disrupted severely by low-voltage conditions, with outage costs exceeding thousands of dollars per minute. Figure 12 depicts typical equipment operating limits for information technology (IT) industry customers. In regions with large IT loads, it is recommended that additional consideration is given to the impacts of low-voltage conditions by increasing amounts of renewable penetration and displacement of conventional units.

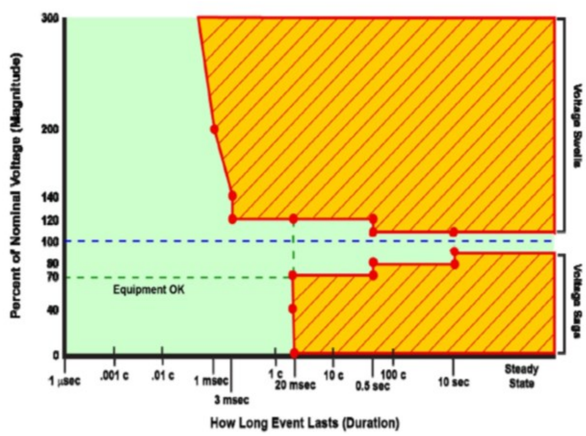


Figure 12: Typical equipment operating limits used by the IT industry [41]

3.3 Mitigation Strategies

Low-voltage violations can be mitigated by a combination of actions at both the system planning and real-time operations horizons. At the system planning level, installation of additional reactive compensation is often the most cost-effective approach. Shunt capacitors should be installed at substations with frequent low-voltage violations and at load centers with high reactive power consumption (i.e. low power factor). Likewise, static VAr compensators (SVCs) and synchronous condensers can be installed at the end of very long transfer paths susceptible to voltage stability issues.

It should be noted that the reactive support provided by shunt capacitors and other static compensation decreases with system voltage. As a result, more fast-acting VAr sources (such as synchronous condensers) may be needed to provide voltage support, especially as inverter-based generation displaces conventional units. It is also unclear if shunt capacitors will provide benefit for short-term voltage stability events coupled with low-voltage ride-through issues. This is an open area of research, with additional studies and analysis recommended in this area.

At the operations level, there are multiple actions that can be taken by the transmission operator to mitigate low-voltage violations. The first is ensuring that all shunt capacitors are switched in and that all reactors are switched out. Next, the operator can raise the AVR setpoint of nearby generators, synchronous condensers, and SVCs. However, this action will have limited effectiveness if the system is already reaching the limits of the units' reactive capability curves. In that case, additional generators should be brought online to provide additional reactive support. If possible, it is preferable to bring generation online near load centers to help reduce the reactive power consumption of heavily-loaded transmission lines. If it is not possible to reduce the power transfer over very long transmission paths, load shedding may be necessary to prevent voltage collapse. LTC transformer tap operation is generally not recommended and will instead worsen low-voltage violations and create additional voltage stability issues.

Most utilities define a schedule of allowable actions and the time within which operators must respond to low-voltage and high-voltage conditions. An example of criteria used by the PJM system operator is shown in Table 3.

Table 3: PJM policy for mitigating simulated post-contingency voltage violations [36]

Voltage Limit Exceeded	If post contingency simulated voltage limits are violated	Time to Correct
Emergency High	Use all effective non-cost actions.	Within 30 minutes
Normal Low	Use all effective non-cost actions.	Not applicable
Emergency Low	Use all effective non-cost actions, off-cost actions, and emergency procedures except Load Shed Directive.	Within 15 minutes, load shed is not used.
Load Dump Low	All of the above including Load Shed Directive* if analysis indicates potential for voltage collapse.	Within 5 minutes
Voltage Drop Warning	Use all effective non-cost actions.	Not applicable
Voltage Drop Violation	All effective non-cost and off-cost actions including Load Shed Directive* if analysis indicates potential for voltage collapse.	Within 15 minutes
Post-Contingency Transfer Limit Warning Point (95%)	Use all effective non-cost actions. Prepare for off-cost actions. Prepare for emergency procedures except Load Shed Directive.	Not applicable
Post-Contingency Transfer Limit	All of the above including Load Shed Directive if analysis indicates potential for voltage collapse.	Within 15 minutes or less depending on the severity

3.4 Operator Workflow Diagram

Figure 13 presents a generic decision tree to represent the sequence of questions and actions that an expert power system operator would use to resolve low-voltage violations, starting with non-cost solutions and working progressively to off-cost and emergency actions.

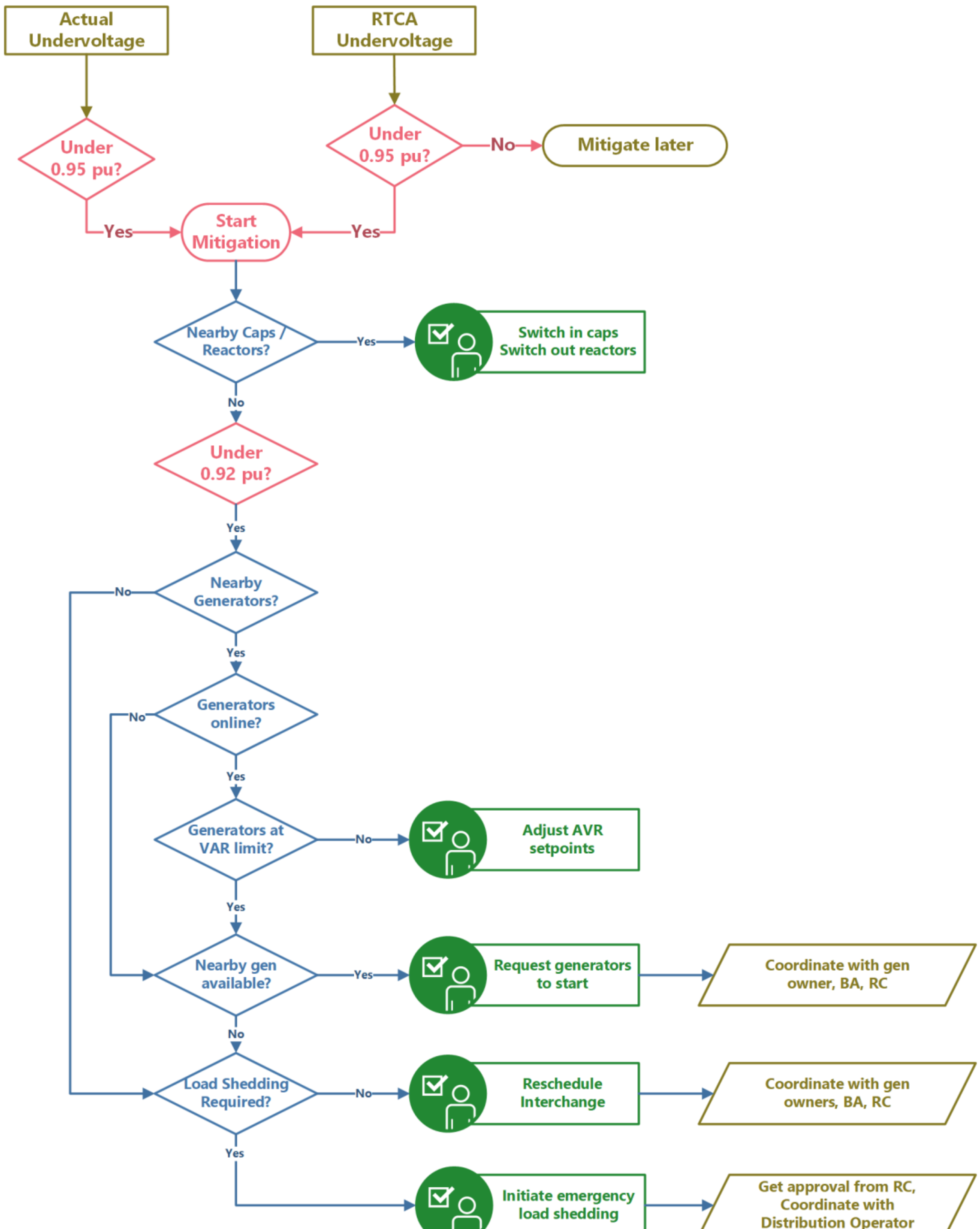


Figure 13: Operator workflow for resolving low-voltage RTCA violations.

4.0 High-Voltage Violations

4.1 Common causes

Unlike the wide array of causes of low-voltage violations, the capacitance and charging MVAr of extra high voltage (EHV) transmission lines during light load conditions are largely responsible for high-voltage violations through a phenomenon known as Ferranti Rise. Table 4 provides typical line charging parameters for various voltage classes of transmission lines and underground cables.

As depicted in surge impedance loading curve of Figure 11 (repeated from earlier), the MVAr consumption of EHV transmission lines shifts to a MVAr injection during low load conditions. The large amount of charging injection from lightly-loaded transmission lines can quickly exceed the absorption capability of the conventional generators operating within their reactive capability curve. This is especially a problem during system black-start restoration when there is very little load on the system. Reactive power injected into the system by line charging can easily cause system voltages to exceed 1.10 per-unit and cause equipment damage. For this reason, it is extremely important to build cranking paths through 115kV transmission lines and ensure that all line reactors and bus reactors are closed in before re-energizing any high voltage lines.

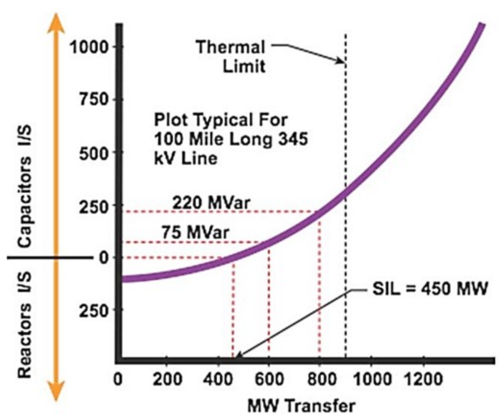


Figure 11: Surge impedance loading curve of a 345kV line, taken from [45]. (figure repeated from earlier)

Table 4: Typical Line Charging Characteristics per km for Various Voltage Levels

Line Voltage	Overhead Line Charging (MVAr/km)	Underground Cable Charging (MVAr/km)
500 kV	1.0 – 1.3	19.0
345 kV	0.53	10.6
230 kV	0.19	5.5
115 kV	0.04	2.1

High-voltage violations can also be caused by mis-operation of voltage control equipment. If transmission operators fail to switch out shunt capacitor and switch in line-reactors and bus-reactors, severe high-voltage violations can result during light load conditions.

Increasing penetration of renewables at the both the transmission and distribution level can exacerbate high-voltage violations through two mechanisms. At the transmission, inverter-based generation operates within a much narrower power factor than conventional generators, thus providing little support for mitigating high-voltage conditions. If the inverter controller is not set to control voltage, but rather provide fixed PQ output or a fixed power factor, then renewable-based generation can rapidly worsen high-voltage problems by injecting additional reactive power and raising system voltage further. Meanwhile, at the distribution level, customer-owned generation and rooftop solar decrease the total feeder load, worsening light loading of the system. If the renewable penetration level of the feeder is sufficiently high, the distribution system may start back-feeding the bulk transmission grid. Most sub-transmission and distribution control and optimization algorithms have not been designed for such reverse flows, resulting in equipment mis-operation and voltage violations.

4.2 Impacts on equipment and customers

High-voltage conditions can cause rapid damage to both utility and customer equipment. The most significant is permanent damage to the insulation of motor and transformer windings. Voltage above 1.10 pu will cause rapid insulation degradation. Although the protective relays of extra-high voltage (EHV) transformers typically prevent any damage during steady-state high voltages, any small surges caused by remote switching operations can cause permanent damage instantaneously during elevated voltage conditions, as illustrated in the equipment photos in Figures 14 and 15.

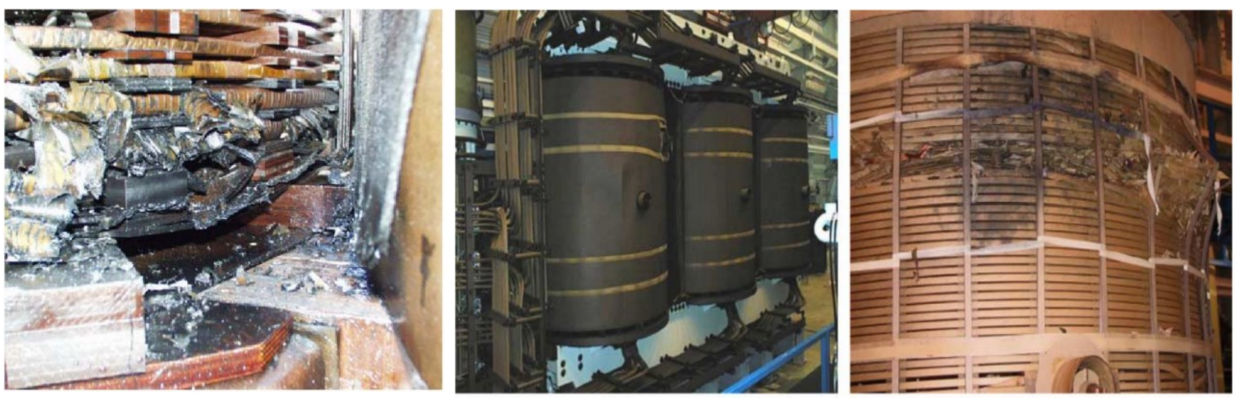


Figure 14: Permanent damage to 400kV transformers caused by over-voltage conditions, taken from [46], [47]

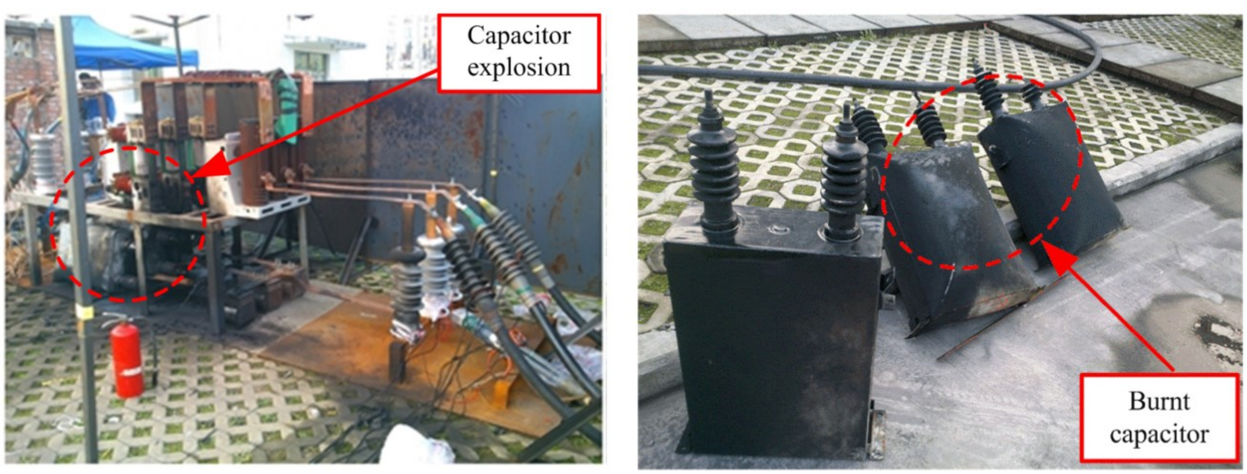


Figure 15: Shunt capacitors damaged by over-voltage during switching, taken from [38]

4.3 Mitigation Strategies

High-voltage violations can be mitigated by a combination of actions at both system planning and real-time operations horizons. At the planning level, high-voltage violations can be resolved by installing line-reactors on EHV transmission lines, as well as bus-reactors and SVCs at EHV substations. Generators at conventional thermal plants that have been displaced by renewables can be converted to synchronous condensers. Transmission-level non-synchronous generation can be set to regulate voltage, rather than power factor or reactive output.

At the operations level, there are multiple actions that can be taken by the transmission operator to mitigate high-voltage violations. The first is ensuring that all shunt capacitors are switched out and that all reactors are switched in. The AVR setpoints of generators, synchronous condensers, and SVCs should be lowered. If synchronous units are reaching the limits of their reactive capability curves, generation should be re-dispatched to increase flows through lightly-loaded EHV transmission lines. Depending on the operating procedures of the utility, 500kV lines may be switched out to decrease charging MVAr injected into the system and increase loading on other lines. Additionally, 500–220 kV transformer taps may be adjusted with great effectiveness to reduce high-voltage violations (note: taps should not be adjusted to correct low-voltage violations). Finally, MVAr may be circulated by adjusting the taps of parallel EHV transformer banks in opposite directions. This technique is highly effective and used by many international utilities to mitigate high-voltage violations at substations without shunt reactors. However, this approach is still considered controversial and not currently practiced by US utilities.

4.4 Operator Decision Workflow Diagram

Figure 16 below presents a generic decision tree to represent the sequence of questions and actions that an expert power system operator would use to resolve high-voltage violations, starting with non-cost solutions and working progressively to off-cost actions. This diagram follows the operator chain of logic that starts with evaluating the severity of the violation and determining whether remedial action is needed. If action is necessary, the operator will then sequentially evaluate individual control actions, starting with switching of shunt capacitors and reactors. If those resources are unavailable, the operator will check if there are local generation resources that could be used for voltage control. If so, the operator will first turn to adjustment of automatic voltage regulation (AVR) and then to generation redispatch. Switching out extra-high-voltage lines is also an approach that can be used with great effectiveness if there are no generation resources and line switching would not impact bulk system reliability for other contingencies.

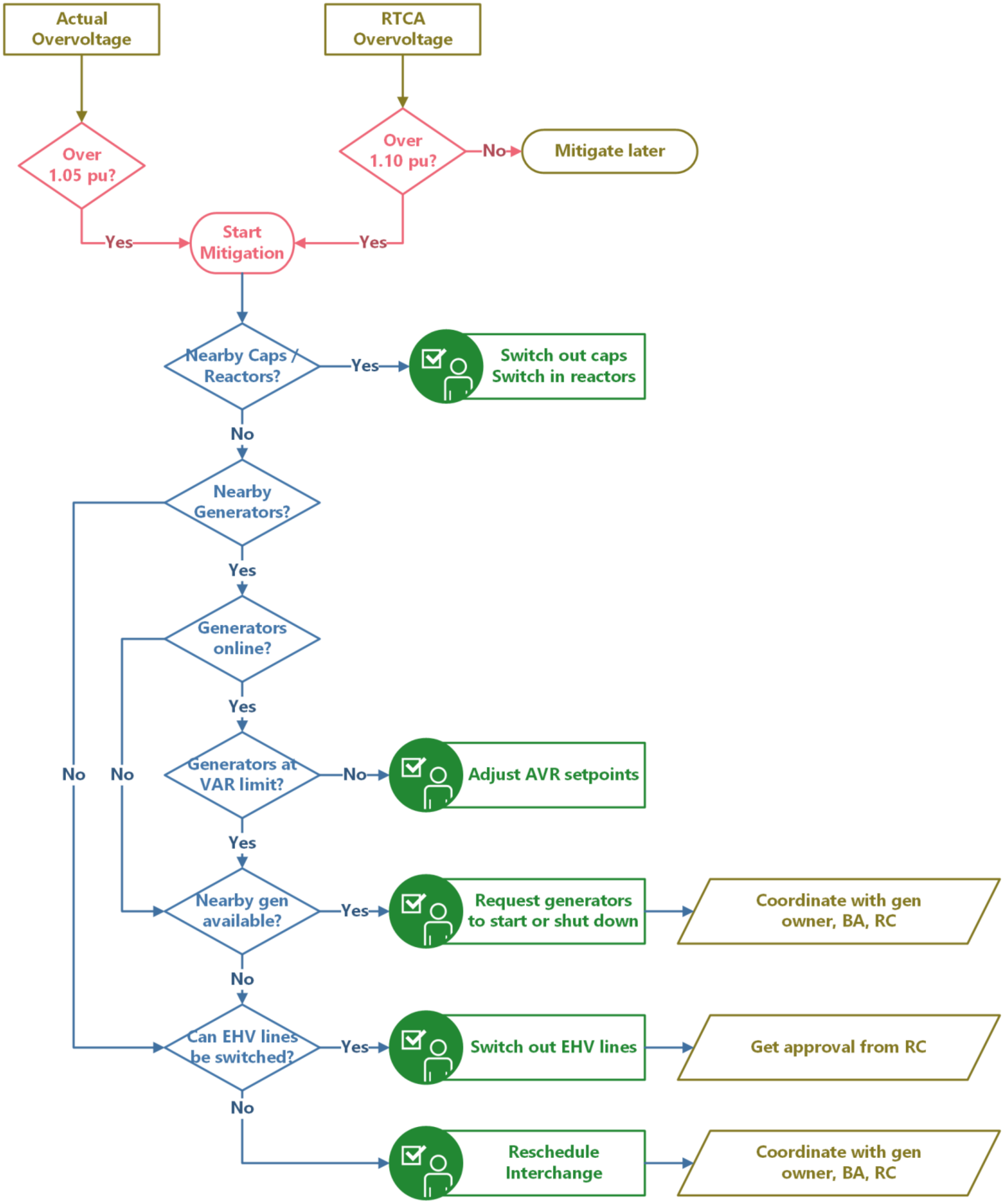


Figure 16: Operator workflow for resolving high-voltage RTCA violations.

5.0 Thermal Overloads

5.1 Common Causes

There are many possible causes of thermal overloads on equipment. Some are related to overall system conditions, and others to outages of equipment. Two system operating conditions that can lead to widespread overloading conditions are extreme heat and extreme cold emergencies.

During extreme heat conditions, the entire bulk electric system for a region will be facing very high system load, which can easily reach or exceed historic system peaks due to air conditioning loads. This is especially true of areas that have historically not experience hot weather but are beginning to see large growth in air conditioning load due to climate change. Additionally, the system may experience generation capacity shortages. In hot weather, power plant efficiency decreases, and some units may be forced offline. The likelihood of thermal overloads is increased further through dynamic reduction of thermal operating limits. For transmission lines, line sag is increased from heat, and the line cannot carry same amount of power as under normal conditions. Likewise, there is a higher risk of overheating of transformers since the transformer cooling fans may not be sufficient to prevent overheating of windings. This is further exacerbated by the possibility of cascading tripping of transformers, in which loss of one transformer will overload others in a banked configuration.

During extreme cold conditions, the system may also easily reach or exceed historic system peaks to plug-in resistive heating loads. In this situation, the cold weather does help mitigate some of the thermal overloading issues, especially for transformers. However, there is this a risk of line tripping due to galloping conductors, which is a phenomenon where ice buildup on wires and high winds can cause the individual phase conductors to slap together and fault. Loss of the transmission line then puts more load on other transmission lines, which could exceed their thermal limit.

Outside of extreme weather conditions, maintenance outages and unexpected tripping of equipment can weaken the bulk electric system and create the possibility of post-contingent thermal overloads. As part of outage scheduling, the TOP and RC will run a day-ahead contingency analysis study to determine whether the outage will result in any thermal overloads or voltage violations. If violations are observed, the outage will be re-scheduled, or the daily operating plan will be modified to redispatch generation to avoid violations. In real-time operations, unexpected tripping of transmission lines and generating units occurs on a regular basis, and the resulting $n-1-1$ condition may contain multiple thermal overloads that the operator must mitigate.

In certain regions with very high penetration of renewables, transmission back-feeding from distributed energy resources (DER) may also become a cause of post-contingent thermal violations of transmission system equipment. Currently, DER hosting capacity analysis is based on the thermal limits of distribution lines and substation transformers and provides a maximum limit of DER that may be installed on the system. However, if the actual installations of DERs begin to approach that limit, reverse power flow on the system may begin to impact transmission operations and contingency analysis results. One TOP with whom the authors spoke has recently been forced to plan for out-of-merit generation dispatch due to day-ahead contingency analysis violations caused by DERs. However, this is an emerging system issue and open area of research with few resources available in the literature.

5.2 Impact on Equipment and Customers

All physical equipment that carry electrical current are subject to a maximum limit of power that they can carry without overheating. If the total power flow exceeds the maximum rating, the equipment may be damaged and will be automatically removed from the system by protective relays. In the case of transmission lines, as the amount of current carried by the line increases, the temperature of wire will increase accordingly, causing it to sag closer to ground. If the clearance between the line and nearby trees and vegetation is too small, the line with short-circuit and experience a phase-to-ground fault. It has been well-documented in the literature that tree-contact by three transmission lines over a short period of time was the initiating event behind the August 2003 blackout.

For substation transformers, the temperature of windings is of key concern. The rate of insulation degradation increases nonlinearly with temperature, and so operators will take emergency control action up to and including load shedding to prevent the transformer exceeding 90% to 100% of its thermal rating. Figure 17 shows a closeup of one of the temperature gauges on a substation transformer. The gauge has two hands, one for the real-time temperature and another draghand needle which records the highest temperature recorded since it was reset. The temperatures of the transformer windings and oil are also often collected via SCADA and sent to the control room for alarming and asset management.

Figure 17: Closeup of a winding temperature gauge with the draghand needle indicating the highest temperature the transformer has reached since being reset.

Thermal overloads of equipment are generally not perceivable to end-use customers. However, if transmission operators are unable to mitigate the overload, the RC may issue a load-shed directive, resulting in rolling blackouts for customers within the affected area.

5.3 Mitigation Strategies

The mitigation strategy for thermal overloads involves the concepts of parallel flows from a source to a sink, as shown in Figure 18. With loss of one tie-line, the power must be carried by the remaining two lines, which may exceed their capacity. The solution is re-routing power to the sink from alternate areas or dispatching local generation within the sink area to reduce the total amount of power that needs to be imported. If neither of these options are possible and there is a risk of a cascading outage, the operator may need to call an emergency load shed directive to reduce the demand in the importing area.

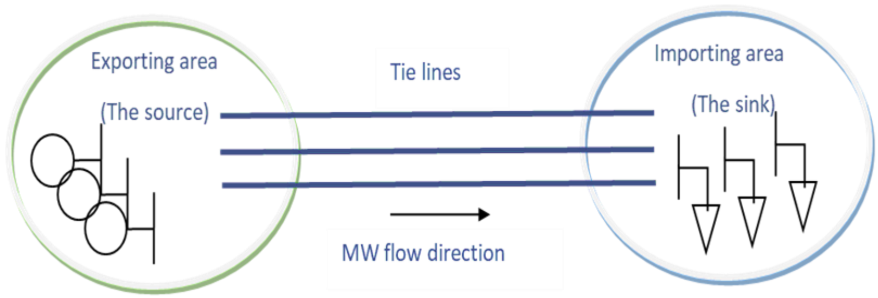


Figure 18. Source and sink concept.

A notable example of successful implementation of pre-contingent violation mitigation of thermal overloads by power system operators is documented in the NERC event observations report on the June 2022 derecho-type storm in Ohio [37]. On June 13-14, record hot and humid weather created heavy system loading, which was then coupled by a set of severe thunderstorms that created a derecho storm with straight-line winds of 80-90 mph (130+ km/h). The storm caused loss of numerous transmission assets, including 26 lines and 31 substations at the 69 kV level, 15 lines and 13 substations at the 138kV level, and one 345kV transmission line. After initial line tripping caused by the storm, TOP and RC performed an $n-5$ contingency analysis and called for 500 MW of pre-contingent load shed to prevent a cascading outage.

As part of the mitigation strategy, the operators took control actions both in real-time and ahead of event. Prior to the storm, the system operators took proactive preventative measures: The RC issued a hot-weather alert and cancelled 22 planned maintenance outages to strengthen system prior to the storm. During the event and subsequent system restoration, the RC and TSO operators talked continuously over the phone to verify system ratings provided by the TSO planning department and compare system configurations prior to taking any control actions. The TSO operators continuously ran system studies during restoration, including real-time contingency analysis, state estimation, and offline engineering studies. This allowed them to coordinate with RC more easily. Finally, the TSO reported to the RC how much load could be shed at each substation. The RC then helped the TSO identify where were the best locations to shed load to relieve n−5 contingency violations at closest point to overload.

5.4 Operator Workflow for Extra High Voltage Branch Overloads

Figure 19 presents a generic decision tree to represent the sequence of questions and actions that an expert power system operator would use to resolve thermal overloads on EHV equipment, starting with non-cost solutions and working progressively to off-cost and emergency actions.

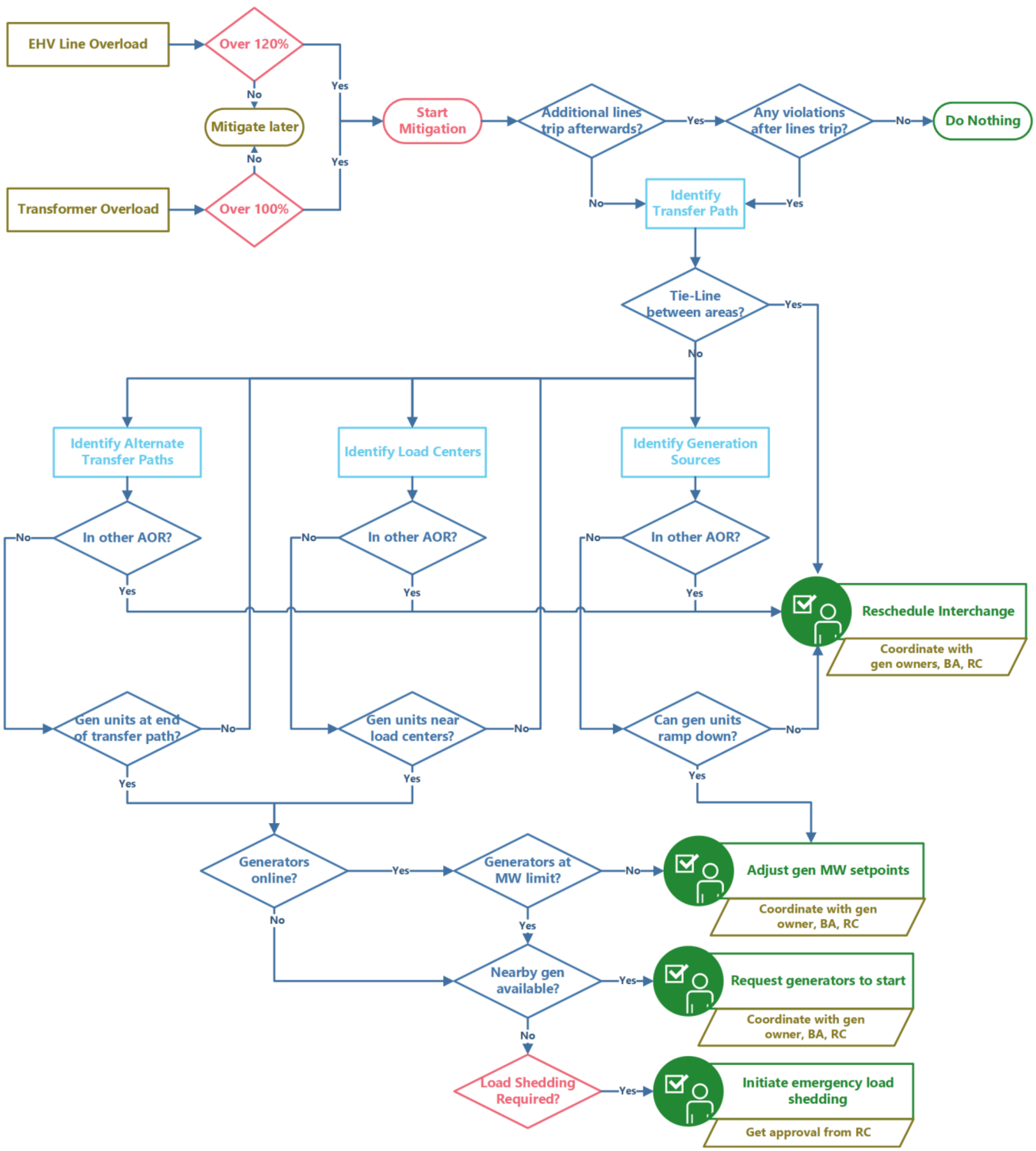


Figure 19: Operator workflow diagram for mitigating thermal overloads on EHV equipment.

5.5 Operator Workflow for High Voltage Branch Overloads

Figure 20 presents a generic decision tree to represent the sequence of questions and actions that an expert power system operator would use to resolve thermal overloads on high voltage and medium voltage equipment, starting with non-cost solutions and working progressively to off-cost and emergency actions.

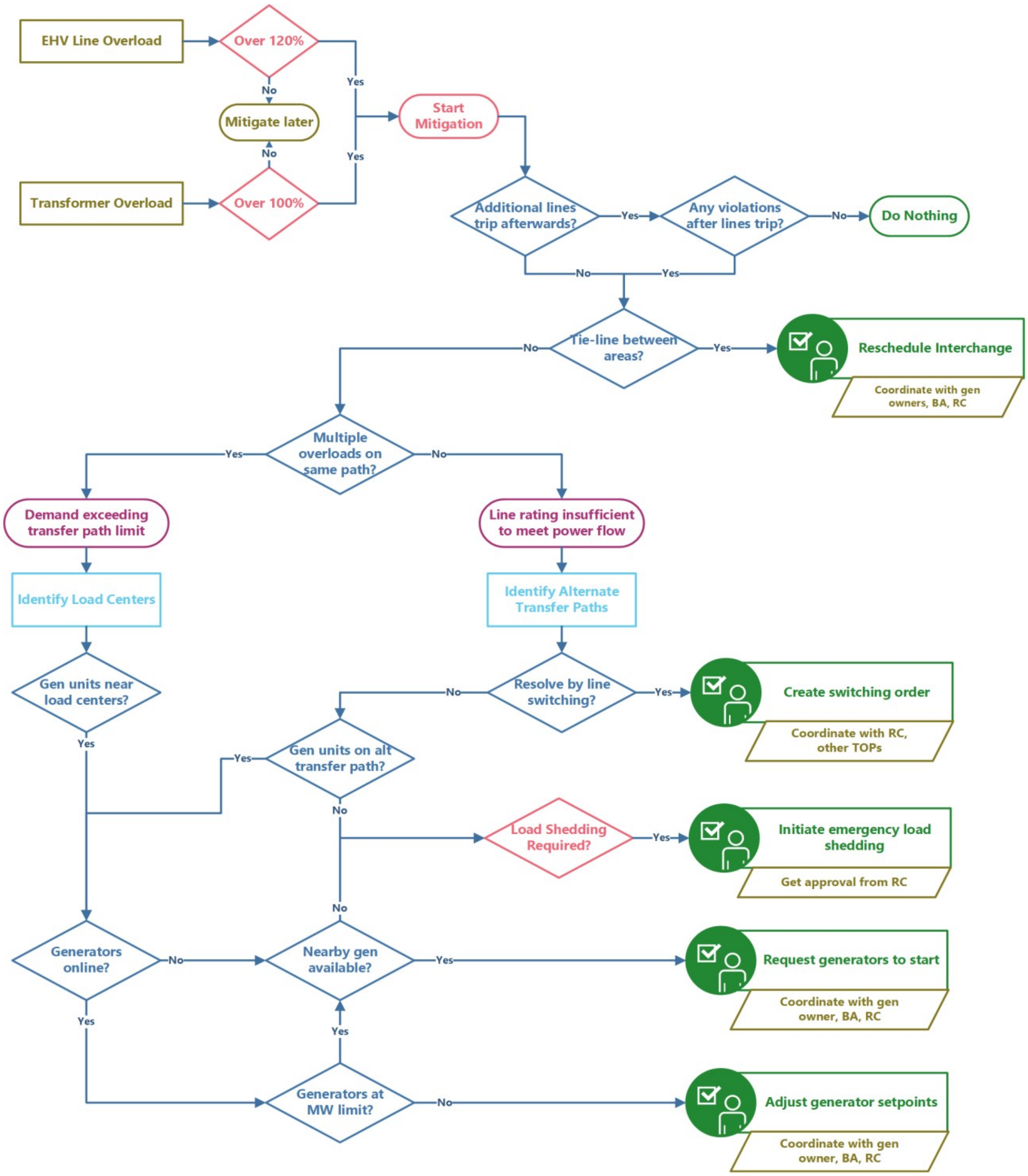


Figure 20: Operator workflow diagram for mitigating thermal overloads on HV equipment.

6.0 Conclusion

This report provided an overview of the types of tools used by power system operators in the control room for ensuring the real-time reliability of the bulk electric system. Real-time contingency analysis is one of most important tools, and extensive discussion was provided regarding the structure of tools used, as well as the limitations of contingency analysis. In situations when the transmission system is near its stability limits, traditional RTCA will fail to converge, and real-time voltage stability and transient stability analysis tools must be used instead. These tools were also introduced in context of the need to study troublesome contingencies and arm remedial action schemes.

This report also provided a summary of operator naturalistic decision-making as a model to describe the process-oriented, high-risk, high-stress environment of power system control rooms. Unlike engineers and optimization tools that compare multiple alternatives simultaneously and then select the best result (based on numerical criteria), power system operators follow a sequential decision-making process based on development and application of situational awareness. Within this process, operators compare the current operating condition to their past experience, and then select a single candidate action based on their understanding of how each type of action would affect overall behavior of the electric grid. Operators then evaluate that single candidate action using a combination of mental simulations and analysis tools in the control room to determine if the action would resolve the situation or if additional actions are needed.

Understanding this process is key to developing the next generation of advanced power applications for control room use. If the logic used by the application or manner in which results are presented do not directly support naturalistic decision-making process of operators, it is likely that the tools will not be used. Human-machine trust issues among power system operators present a particular challenge to introduction of new tools, which may be rejected by end-users. The unique work culture, experience requirements, and procedures-based approach of control room work present further barriers. Although these challenges are anecdotally well-known by industry practitioners, few citable sources exist in the literature for how operators use existing and new tools in the control room.

To that end, this report presented a series of detailed logical flowcharts to explain the sequence of decisions that operators use to resolve various types of contingency analysis violations, including low-voltage violations, high-voltage violations, and thermal overloads of branch elements at both the high-voltage and extra-high-voltage levels. To provide context for each of these workflows, additional operations-focused materials were provided regarding the underlying causes of each type of violation, impacts on customers and/or the bulk electric system, and mitigation strategies used by power system operators.

It is anticipated that this report can serve as a guideline for both researchers and industry practitioners seeking a better understanding of operator decision-making. Gaining such an understanding and incorporating operator cognitive process into new advanced power applications can help build human-machine trust and lower the barrier to adoption of new tools in the control room. Although this work provides a detailed description of RTCA tool usage, more research is urgently needed to improve understanding of operator cognitive processes and create numerical frameworks for evaluating the effectiveness of new control room tools for other tasks.

7.0 References

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