NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Reliability Concepts

Discussions about:

- *Managing Risks*
- *Credible Contingencies*
- *Acceptable Performance*
- *Timeframes*
- *Boundary Conditions*
- *System Operating Limits*

Version 1.0.2

Change History

Version 1.0.2 – Format repairs, December 19, 2007

Version 1.0.1 – Format repairs, December 14, 2007

Version 1.0.0 – Approved by Operating Committee and Planning Committee, December 12-13, 2007

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Foreword

We began this project in 2003 simply to update our definitions of the terms System Operating Limits and Interconnection Reliability Operating Limits. But simply defining those terms still left them open to interpretation because they depend on definitions of other terms, like “wide area” and “single contingency” and “violation time (Tv).” What is a single contingency? What encompasses a “wide area?” How do system planners consider operating limits in their plans? Why do we list our standards in a table in Standard TPL-001, but in a narrative form in FAC-010 and -011? Are these really planning “criteria” and operating “criteria,” and are they the same? If not, why?

For all these reasons, in 2006 it became clear to both the Planning Committee and Operating Committee that we needed to revisit the concept of operating limits.

Historically, we have planned and operated the Interconnections so that the next disturbance, event, or equipment failure that is likely to occur will not cause any area of the Interconnection to become unstable and lose its integrity, or cause generation or transmission equipment to operate outside its normal limits. These rules and principles comprise our *reliability criteria* for planning and operating the Interconnections, and these criteria, in turn, form the basis for our reliability standards.

Some of the earliest documents on NERC’s reliability criteria include the “NAPSIC[1] Minimum Criteria for Operating Reliability,” (1970), and NERC’s “An Overview of Reliability Criteria Among the Regional Councils,” (1982). NERC updated the latter document, which deals with system planning, in the 1990’s. The NAPSIC criteria evolved into the Operating Policies and then the NERC reliability standards that deal with interconnected systems operation.

NERC has not reviewed these criteria for several years. They are still technically valid and, if we apply them rigorously, help keep our reliability standards focused. However, events over the last decade, including 1.) electric power generation deregulation, 2.) open transmission access, 3.) the resulting dis-integration of many (but certainly not all) vertically integrated utilities that NERC subsequently reflected in its Reliability Functional Model, 4.) the associated rewriting of NERC’s reliability standards in terms of the Functional Model, 5.) the “responsible entities” that now include many small utilities that had previously been part of larger control areas, and 6.)

[1] North American Power Systems Interconnection Committee, the NERC Operating Committee’s predecessor.

FERC's interest in the technical merits of those standards as NERC became the Electric Reliability Organization, prompt us to re-examine our operating and planning reliability criteria.

What all this means is that the planning and operating boundaries—what's "your" system versus what's "my" system—overlap or blur. Balancing authority areas and transmission operator areas may not be the same. Reliability coordinator boundaries don't necessarily line up with Regional Reliability Organizations. So the notions of "wide area" or "cascading" take on new perspectives. Is a "wide area" at least two balancing areas? Two transmission systems? Is a reliability coordinator's footprint, say California ISO, wide enough itself? Do PJM *plus* MISO define a "wide area?" How about ERCOT? TVA? The Los Angeles metropolitan area?

* * *

What we've learned by writing this Reliability Criteria and Operating Limits Concepts document and talking to the Operating Committee and Planning Committee and their subgroups is that our reliability criteria are based on many underlying assumptions and nuances that everyone may be aware of, but not everyone fully appreciates or agrees with. Therefore, the Operating Limit Definition Task Force decided to step back to the ideas *behind* those reliability criteria. And what we concluded led us to this collection of conversations about six concepts that are divided into two sections:

Philosophical concepts

1. Managing risk
2. Credible contingencies
3. Acceptable performance

Technical concepts

4. Boundary conditions
5. System operating limits
6. Timeframes

This document discusses each of these concepts, and then suggests how each contributes to the planning and operating criteria upon which our reliability standards should be based. One of our "byproducts," so to speak, are definitions of System Operating Limit and Interconnection Reliability Operating Limit, which is what we set out to write.

Judgment. We often use the word "judgment" in this document because the words "risk," "credible," "likely," and "acceptable" do not lend themselves to exactness. Whether the consequences of a risk are acceptable is, more often than not, arguable, inexact, and changeable. Only through our experiences, lessons learned, engineering expertise, and managing expectations will we arrive at the "right" set of reliability criteria and standards. And that's why judgment is important.

That said, we understand that NERC's reliability standards cannot set a level of judgment. What they can do, however, is provide the agreed-upon parameters that one must consider when arriving at informed decisions.

Final thoughts

This document is not a criteria, standard, or what we would call in the new age a "paradigm shift." It's neither a defense nor criticism of current practices. The OLD-TF tried to put all, or at least most, of these ideas aside (not always easy!). Then the task force backed up all the way to the beginning: the ideas of managing risk and expectations.

We expect this document to be the starting point for discussions, not the end point that's been decided.

Introduction

The concepts of operating and planning criteria and system operating limits are key to developing reliability standards that are technically sound. These concepts explain why system planners consider certain “contingencies” when developing their plans, why contingency analysis is so important to system operators, and how the planning, operations planning, and real-time operating timeframes are similar—and different.

History. The NERC Operating Committee formed the Operating Limit Definition Task Force (OLD-TF) in November 2002 to address a report to the NERC Board of Trustees that highlighted violations of NERC operating policies and regional standards requiring system operators to report “Operating Security Limits.” The report appeared inconsistent across the Regions, and the OC concluded that the inconsistent or incomplete reporting of OSL violations was caused by 1.) an imprecise definition of an “OSL violation,” and 2.) unclear actions that Reliability Coordinators and other operating personnel are expected to take to return the system to a safe operating state as quickly as possible. As a result, the OC asked the OLD-TF to clearly define “Operating Security Limit” and the requirements for reporting OSL violations.

In March 2003 the OLD-TF submitted a report to the Operating Committee suggesting that there were, in fact, two types of Operating Security Limit violations:

1. Those that would affect only a “limited set of facilities” were called System Operating Limits (SOL), and
2. Those that posed a serious threat to the reliability of the bulk power system, such as instability, uncontrolled loss of Interconnection integrity, or voltage collapse, were called Interconnection Reliability Operating Limits (IROL).

The OLD-TF also noted that Reliability Coordinators and other system operators needed to recognize 1.) when the system was operating beyond its operating limits, and 2.) the importance of returning the system to a safe operating state as quickly as possible.

To address this second observation the OLD-TF surveyed the Reliability Coordinators to find out how they calculated Interconnection Reliability Operating Limits and how they mitigated IROL violations. The survey results pointed to the need to clarify the definition of SOLs and IROLs themselves, the definition of SOL and IROL violations, and the (former) NERC operating policies that set the SOL and IROL compliance violation limits, or Tv.

In 2005 NERC translated the Operating Policies into individual Reliability Standards that were then organized into various categories. As a result, the references to IROLs and SOLs in many of those standards lost their context when read by themselves, as was quite apparent in the May 2006 FERC assessment of NERC Reliability Standards and NERC's response to that assessment. Furthermore, recently adopted standards FAC-10 and -11 include the term "system operating limits" in both the operating and planning "horizons." One might infer these limits are the same in both horizons, and in a general sense that's true. But as we'll explain in this document, system operating limits are real-time operating limits derived from "boundary conditions" calculated in the planning and operations planning timeframes that take on different dimensions as we move towards real-time.

In 2006 we expanded the Operating Limit Definition Task Force to include members of the Planning Committee, and also expanded the scope of their work to look at operating and planning criteria concepts, realizing that clear criteria are important for developing relevant reliability standards.

This document is the result. It explains the concepts behind NERC's reliability criteria and how these criteria and concepts are applied in the planning, operations planning, and real-time operations timeframes. It ends with definitions of System Operating Limit and Interconnection Reliability Operating Limit that are somewhat different than what we have in our standards today.

The "Interconnection." We use repeatedly the term "Interconnection" because that's our playing field. While we usually think of planning and operating the "bulk power system," system planners and operators realize that, in reality, the distribution system and the customers' loads—whether they be light bulbs or air conditioners or arc furnaces—are connected to the bulk power system and contribute to the performance of the entire Interconnection. The Reliability Concepts discussed in this document are not intended to address distribution system engineering or operations, or set any specific levels of customer service. But the concepts presented in this document recognize that the operation of the bulk power system directly affects the supply to the distribution system and, therefore, end-use customers. In that sense, one could think of the concepts in this document as pertaining to the "delivery point performance" of the transmission system, or where the transmission system connects to the distribution provider.

Styles in the Document

Important points. Points or conclusions that are especially important in are flagged with the "i" ball at the left.

Marginal notes. Topics or "side-bar" comments that are related to the discussion are placed in marginal notes as on the right.

Marginal notes. These deal with related issues, or define a term or explain a phrase in the main text on the left.

Reliability Criteria: Philosophical Concepts

Managing Risk

We begin our discussion of reliability criteria with a discussion of *risk*. In everyday terms, risk is the likelihood that something will happen that causes damage, injury, or loss. Stating this a bit more analytically, risk is the combination of two things: 1.) the likelihood that something will happen, and 2.) the consequences if it does.

In the context of electric system reliability, risk is the *likelihood* that an operating event will reduce the *reliability* of the Interconnection to the point that the *consequences* are unacceptable. (Figure 1) Because we cannot prevent events from happening, we plan and operate the electric system so when they do, their effects are manageable, and the consequences are acceptable. So one of the keys to providing a reliable Interconnection is managing risks.

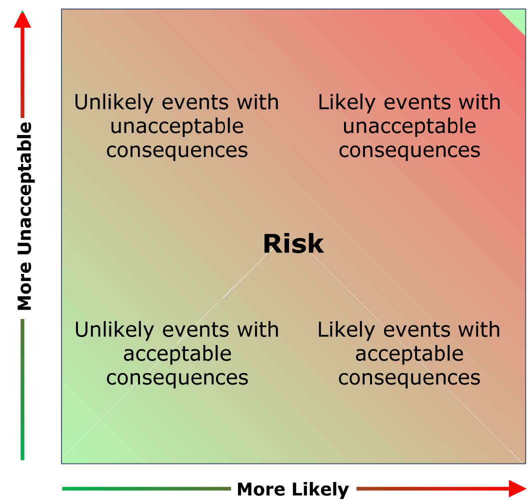

Figure 1 - Whether risk is acceptable is a function of two parameters: 1.) the likelihood that an event will reduce the reliability of the Interconnection, and 2.) the consequences if it does.

Acceptable consequences and managing expectations

Before we delve further into which consequences are "acceptable" and which aren't, we need to talk about *expectations*, both the customer's and NERC's.

The customer's expectations

Simply stated, customers expect uninterrupted electric service—or nearly so—for their own health and welfare. We know our societies rely on electricity; we needn't say more.

NERC's expectations

On the other hand, and just as simply stated, NERC expects to 1.) maintain real-time Interconnection integrity (which could otherwise cause a cascading blackout), and 2.) protect the generation and transmission equipment from catastrophic damage (which could jeopardize reliability for weeks or months).

Interconnection "Integrity." By "integrity," we mean that the transmission system is interconnected with equipment intact and voltages within safe limits. It does not necessarily mean that it can serve the entire customer demand.

The nature of synchronized, interconnected operations relies on a contiguously and continuously connected—and managed—generation and transmission network, and NERC is responsible for developing the standards for planning and operating that network (the

"Interconnections"). So important are these principles that the system operator will, on occasion, disconnect customers from the Interconnection to maintain its integrity or protect generators or transmission facilities from severe damage, and NERC standards clearly require system operators to do precisely this, pre- or post-contingency (we will discuss this later). Indeed, the failure to maintain Interconnection integrity and protect generation and transmission equipment will absolutely lead to blackouts, long restoration times, or electric service curtailments, none of which meet the customer's expectations, and all of which jeopardize our nations' health, welfare, and security.

Loss of customer service. For these discussions, there are several ways customers can lose service: 1.) when they are automatically disconnected by protection systems including, but not limited to, underfrequency or undervoltage load shedding relays following the loss of Interconnection integrity, 2.) when they are manually disconnected when other means are not available to maintain Interconnection integrity or to protect transmission or generation equipment, and 3.) when the transmission equipment they are connected to fails or is disconnected.

We do not consider interruptions from momentary voltage "blips" as loss of customer service. That's a power quality issue that NERC standards do not cover.

We plan and operate the Interconnection to 1.) maintain its integrity, and 2.) protect its equipment. These are what we consider the acceptable consequences following operating events.

From this very important statement rise two overarching questions:

1. How do we manage risk so that operating events will result in these acceptable consequences?
2. How do acceptable consequences translate into customer service?

How system planners manage risk

System planners manage risk through well-established substation and protection system design and logic that reduces the chance that likely events will jeopardize the reliability of the transmission network. For example, substation circuit breaker configurations are designed to isolate (contain) transmission equipment failures so they don't cascade into widespread Interconnection integrity failures—an unacceptable consequence considering the likelihood of single element[2] failures.

The transmission system is designed and operated to isolate events such as transmission line or transformer faults, breaker or switch failures, or generator trips, preventing them from causing the Interconnection to lose its integrity. Therefore, the only customers whose service should be interrupted are those directly connected to the piece of equipment that failed or tripped. As long as we maintain Interconnection integrity, we do not expect other customers to lose service as a result of these very likely events. (See "Loss of Customer Service" at right.)

A more severe event—say the failure of two or three 500 kV lines serving a substation—calls for other expectations. We would still

[2] By "element," we mean a transmission line, transformer, circuit breaker, switch, etc. We use the term "element," "facility," and "equipment" interchangeably, and for the purposes of this document, they mean the same thing.

expect the Interconnection to maintain its integrity, but considering the unlikelihood and severity of this particular event, we would judge as acceptable automatic load shedding at surrounding substations to prevent the loss of Interconnection integrity (through voltage collapse) or manual load shedding to protect transmission equipment, or both. Failure to do either could threaten Interconnection integrity, which can take hours or days to reestablish. Or, just as bad, could damage or destroy transmission equipment that might require weeks or months to repair or replace. Clearly, a relatively short customer outage is an acceptable consequence if it avoids loss of real-time Interconnection integrity or equipment damage that could result in longer duration outages.

How system operators manage risk

System operators manage risk in real time by monitoring and controlling generating dispatch and reserves, line flows, voltage profiles, load-generation balance,[3] etc., for two primary reasons: 1.) Maintain Interconnection integrity, and 2.) protect generation and transmission equipment from catastrophic failures. The operator's success in achieving these expectations during normal operating conditions, emergencies, and system restoration directly affects customer service in the short and long term.

Coordinated planning and operations

Utilities began interconnecting their transmission systems in the 1920's, which enabled them to reduce the chance that an event on their combined systems would result in unacceptable consequences. (It also allowed the utilities to take advantage of the north/south seasonal load diversities). We have learned through experience the kinds of risks we can manage through interconnected systems operation. For instance, by tying their transmission systems together and sharing operating reserves, utilities reduce the chance that the failure of a generator (a likely event) will cause customers to lose service or damage transmission equipment, or even worse. Furthermore, the larger interconnected system is more stable and better able to withstand contingencies.

Coordinating transmission service, interchange between balancing areas, and transmission planning doesn't prevent generators from failing or transmission faults from happening. Rather, they manage the

[3] To help maintain Interconnection frequency.

risk by ensuring the consequences are acceptable when these inevitable events happen.[4]

Unavoidable risks

But the brutal facts, as they say, are that utilities cannot afford to build or operate the Interconnection to avoid *all* risks. The generation and transmission systems are finite and limited and always will be. At some point, the failure of a significant number of transmission lines will cause part of the Interconnection to become unstable and lose its integrity, regardless of automatic or system operator actions. And hurricanes and ice storms will take their toll.

All the world's money cannot construct an electric system robust enough to remain unscathed from extremely unlikely and extremely severe events. While the consequences may be vast, some risks are simply unavoidable. Saying these consequences are also unacceptable is moot. Saying we don't want the events to happen is obvious.

Acceptable risks

It is just as pointless to assume that *every* disturbance, event, or equipment failure will reduce the reliability of the Interconnection. If we know (not simply assume) the failure of a radial transmission line, while likely, has little or no effect on the integrity of the 230 kV network that feeds it (i.e., the reliability consequences of building this radial line are known and acceptable), then the risk is acceptable. Conventional wisdom does not justify the costs of constructing duplicate transmission facilities or extending the far end of every radial line to another point on the high-voltage network.

There may also be occasions when we operate part of the Interconnection even after it has lost its integrity. For example, shortly after a hurricane, the utility may be able to quickly and temporarily "patch together" its transmission system with radial spurs that would not meet NERC's (or even the utility's own) planning reliability criteria. And while the utility may choose to operate to a lower level of reliability, it should not operate the damaged part of the Interconnection in a way that jeopardizes 1.) the integrity of the parts that are still intact, nor 2.) the generation and transmission equipment in the fragmented area. (Remember: Interconnection integrity and equipment protection are first and foremost). The utility may consciously decide to operate these fragmented sections in this manner if its customers are to have any electric service. The customers on those parts of the grid are susceptible to even the most likely, single

[4] Interconnected systems operation also reduces costs by exploiting the natural diversity of generator failures.

equipment failures, but we would consider this to be an acceptable risk considering the circumstances while the utility rebuilds its transmission network to reestablish the damaged network's integrity. In this case, the adverse consequences of *not* connecting the fragmented sections to provide electric service as soon as physically possible are unacceptable.

Restoration. During restoration periods, our focus changes from the risk of interrupting customers to the risk of damaging equipment.

While hurricanes rip apart the transmission system, blackouts disconnect the generators (and may damage them in the process). Depending on how many generators are 1.) still on line after a blackout, 2.) off line but undamaged, and 3.) off line and broken, the system operator may be forced to accept risks to customer service during the restoration period that would be unacceptable at other times. It's quite possible that the process of orchestrating the generator and customer reconnections will be interrupted by various smaller scale blackouts as the system operator reestablishes the transmission system's integrity, balances generation to load, and maintains voltage and angular stability. While we know the transmission system may be operating outside the boundary conditions that were used in the planning and next-hour operations planning studies we accept these risks. During this period, operating limits are mostly aimed at keeping generation and transmission equipment within *their* limits to avoid catastrophic damage. While we accept the risk that credible contingencies may interrupt customer service during the restoration period, we cannot accept the risk of damaging generators or substation equipment, which typically require long, expensive repairs. The system operator should know from studies, training, and experience the operating limits he needs to stay within while restoring the system and how those limits change thorough the stages of establishing network integrity, and up to normal interconnected operations.

Event severity and customer service

The table below shows in two dimensions what we've been explaining in one: System operators always expect to 1.) maintain Interconnection integrity, and 2.) protect generation and transmission equipment. But as the events become more severe and more difficult to contain, they may need to interrupt customer service, either pre- or post-contingency, to meet our expectations.

Table 1 - Examples of how Interconnection events can affect customer service.

Event	Possible Effects on Customer Service
Single-element failure	Customers served exclusively by faulted element(s) lose service.
Line fault with delayed clearing	Customers served by impacted element(s) lose service.
Substation failure	Customers served by substation lose service.
Simultaneous single element faults (multiple contingencies)	Depends on severity of the contingencies.
Severe equipment overload	Customers are manually interrupted to protect equipment.
Unable to maintain ACE	Customers are manually interrupted to re-establish balance.
Voltage or system instability	Customers are interrupted by undervoltage relays or manual load shedding.
Islanding (imbalance)	Customers are interrupted by underfrequency relays or manual load shedding.
Restoration	Any of the above are possible.

So far, we have expressed acceptable consequences in terms of preserving Interconnection integrity and protecting[5] generation and transmission equipment, leaving "local" reliability to the purview of the utility or reliability council.

As we explained earlier, NERC does not establish distribution performance criteria, power quality requirements, or standards on customer service. However, NERC's role as the ERO also includes responsibilities for critical infrastructure protection and national security. Reliable transmission service to metropolitan areas and offsite power to nuclear generating stations are two examples of "local" reliability that rises to NERC's attention. While interrupting electric service to, say, Montreal, New York, Toronto, Chicago, Dallas, Los Angeles, or Vancouver may not jeopardize the reliability of the Interconnection, they are unacceptable nonetheless because the societal impact or national security consequences may be too widespread and severe. The continuity of offsite power to nuclear power plants is critical to their ability to provide a reliable electricity resource and meet regulatory requirements.

This does not mean that service to large metropolitan areas or nuclear generators takes precedence over overall Interconnection integrity and equipment protection. It does mean system planners and operators consider these critical loads when developing the boundary conditions in the planning and operations planning timeframes, and the operating limits in real-time.

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[5] By "protecting," we mean avoiding damage from operating the equipment beyond its safe ratings. We are not referring to physical protection.

Summary

1. Customer service depends on 1.) maintaining the integrity of the Interconnection, and 2.) protecting generation and transmission equipment from catastrophic damage.
2. The degree to which customer service is interrupted is a function of the likelihood and severity of the event, and how well it can be contained.
3. While it’s impossible to eliminate risks, it is possible to manage them.
4. Reliability criteria is based on managing these risks by planning and operating the Interconnection to reduce the chance that an event will jeopardize its integrity or severely damage the generation and transmission equipment.
5. Consequences that are unacceptable in some situations are acceptable in others—and vice versa. It depends on the nature and location of the event.
6. In some cases, such as during restoration from a blackout or catastrophic natural event, system operators might operate a portion of the Interconnection that has become fragmented or radial at greater risk as long as doing so doesn’t 1.) jeopardize the integrity of other parts of the Interconnection that are still intact, or 2.) severely damage generation and transmission equipment.
7. In some cases, planners and operators will plan and operate the Interconnection to withstand events for which the consequences to local or national security are too great to ignore. This includes service to metropolitan areas and nuclear power plants.

Reliability Criteria: Technical Concepts

We now move from the philosophical concepts of reliability criteria to the technical. We'll translate *events* into *contingencies*, and *acceptable consequences* into *acceptable performance.* And we will cover Interconnection restoration.

Contingencies

In the first section we discussed *risk.* In the context of the reliability of the Interconnection, risk has two parts: 1.) the *chance* that a future event will jeopardize reliability, and 2.) the *consequences* once that event happens.

Analyzing the past to predict the future. By analyzing past events, we learn what is credible and what isn't. Some events are not obviously credible until we analyze trends over several years. For example, the utility industry has considerable experience in tracking generator reliability through the NERC Generator Availability Data System.

Utilities refer to future events as *contingencies.* In its broadest definition, a contingency is an event that may occur in the future, that needs to be dealt with, and therefore must be prepared for.

Credible contingencies. It's impossible to stop contingencies from happening, nor predict with certainty when they will occur or their severity. But we can, and do, analyze them after they happen, and from this analysis and sharing "lessons learned" and best practices glean a better understanding of what kinds of contingencies are *credible* and how to reduce their likelihood.

A credible contingency has two attributes: 1.) *plausibility* (believable), and 2.) *likelihood* (probable). For example, we know from experience, analysis, and common reasoning, that the failure of a single transformer or transmission line or generator are all plausible. So is the failure of an entire multi-generator power plant or the collapse of two transmission lines on a common right of way, though these last two examples are less likely (less probable). All are credible contingencies. We also know the consequences of each of these contingencies, not only from our experiences after these events happened (event analysis), but also from system simulations and studies ("*what if they happened*?"). The simultaneous failure of seven 500 kV lines serving three substations due to five delayed clearing breakers and three wave traps is so unlikely or implausible (take your pick), that this would not be a credible contingency. If it happened, we would expect a fairly large area of the Interconnection to lose its integrity with cascading outages at other substations. So the set of credible contingencies range from those that are more likely to those that are less, and those that plausible to those that aren't, and a corresponding range of expectations of acceptable consequences.

Are acts of nature contingencies? Not per se. They are events that trigger contingencies. Lightning, a contaminated insulator, brush fire, or airplane can all trigger a line fault.

Critical contingencies. But there's another variable: *criticality*. Two contingencies with the same likelihood and plausibility may have very different consequences. The failure of a 230/138 kV transformer in one part of the Interconnection may have a very different effect on the surrounding network than the failure of a 230/138 kV transformer in another. One may play a key role in reactive support, and so its failure would be more critical to Interconnection integrity, while the other would hardly be noticed and not be critical at all. Or, the failure of a particular 230/138 kV transformer may not be critical today, but very critical tomorrow when other lines are out of service for maintenance.

“Critical facilities.” “Critical facilities” do not comprise a defined list. Whether a facility is “critical” depends on how its operation affects other parts of the Interconnection, which can vary from one hour to the next.

Therefore, the system planner, operations planner, or real-time operator will develop various planning requirements or operating rules (sometimes called “guides”) for managing risk under certain conditions or situations.

Judgment of credibility and criticality

Neither “likely,” “plausible,” or “critical” are exact—they extend over a continuum from “very” to “not,” and all points in between. Some events are more likely or plausible than others, and some are more critical than others, and so we are faced with yet another judgment on the degrees of likelihood, plausibility, and criticality and how all three relate to acceptable performance. The industry will decide how to define these terms in our criteria and reliability standards. However, individual system planners, operations planners, and operators will also have to judge for themselves whether an event is *more likely, plausible, or critical on their own systems* to include in their boundary condition studies, operating guides and limits, and mitigation procedures. We raise these points in this document as concepts that need to be considered.

We cannot emphasize enough the roles experience, judgment, and analysis play in how we plan and operate the Interconnection. From *experience* we know which kinds of contingencies are more or less plausible and likely to occur, and which are more or less critical. Tracking and analyzing past events helps us *judge* the kinds of contingencies that are credible or critical (or both) and their consequences. Then *analyzing* these contingencies in the planning and operations planning timeframes lets us predict how the Interconnection will perform when and if these events happen.

The important point is that we plan and operate the Interconnection so that credible contingencies result in acceptable performance. And after these contingences happen, the system operator is able to adjust the system to be able to handle the next credible contingency.

Single- and Multiple-Element Contingencies

We tend to think of contingencies as “single” or “multiple.” Hence the expression “n-1” when we are referring to the failure of a single element like a transformer or generator, or “n-2” then we are referring to, say, a double-circuit transmission line, or two generators at a power plant. But while this seems perfectly logical, it’s not correct because sometimes separate *elements* are either physically or electrically linked so that when element A fails or trips off or is disconnected, element B goes with it. (Though not necessarily vice versa. See marginal notes on “Elements, Facilities, and Equipment,” and “Elements in Planning and Operating Studies” at right and the section “Protecting Equipment” on page 27.)

So, for all intents and purposes, 1.) the simultaneous failure of two single elements that are electrically or physically linked may be almost as likely as the failure of either element separately, so 2.) some multiple-element contingencies are credible, and 3.) the expression “-1” could refer to either the failure of a single element or the failure of multiple elements that are physically or electrically linked and failed together as one. Therefore, single contingencies may be single-element or multiple-element.

“Elements” in planning and operating studies.

Generally speaking, planning studies are “nodal” and consider facilities while operating studies may consider elements that make up facilities.

Single-element contingencies

Examples of single-element contingencies include 1.) single phase-to-ground faults, 2.) phase-to-phase faults, 3.) three-phase faults, 4.) generator failures, and 5) the disconnection of any element without a fault. In each case, only one element is affected within a particular zone of protection (see text box “Zone of Protection.”)

Zone of protection refers to a region of the Interconnection with a defined set of *elements* is protected by a defined set of relays.

Historically, NERC accepts the presumption that the failure of any single element is a likely event and a credible contingency.

Multiple-element contingencies

Physical relationships. We may find, on occasion, that a single event involves the failure or misoperation of two elements. It’s likely that two transmission lines (separate elements) sharing the same towers will both short circuit if the towers collapse, or if lightning strikes the towers (Figure 2). Also, some stations are designed with multiple circuits terminating on a common bus through separate breakers for each line. In this case a failure of the bus will interrupt several circuits.

Both of these examples—the tower failure and common bus failure—are *single* contingencies involving *multiple* transmission elements that are physically related (two lines attached to the same tower or multiple lines served from a common bus).

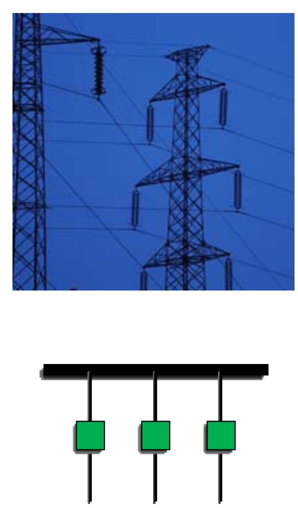


Figure 2 – Two circuits on the same tower and three breakers connected to the same bus are examples of multiple elements that are physically connected and whose failure is a credible contingency.

A less obvious example would be two generators that the plant operator has temporarily connected to the same station service bus. The failure of that bus will trip *both* generators. So, in this configuration, the simultaneous failure of two generators may be a credible contingency because their auxiliary equipment is physically connected to the same bus. The system operator needs to know this configuration exists[6].

While less likely than single-element failures, experience may show these *multiple-element* events are plausible, likely enough, and critical enough to be treated as single contingences. System planners and operators would include them in their own planning requirements and operating guides, and what we judge as acceptable performance following these events may be different than single-element single contingencies.

Electrical-physical relationships. We expect protection systems, such as circuit breakers, to discretely remove faulted equipment from the transmission system and therefore contain the failure to a very small area. But we know from experience that single phase-to-ground faults sometimes fail to clear because of a stuck breaker at one end of the line. In this case, what appears to be two separate events (the fault and then the stuck breaker) *may* be a single, multiple-element credible contingency if our experience reveals the particular transmission configuration, breaker type or manufacturer, are more prone to this type of failure. There's an electrical relationship because the fault caused the relay to trip the breaker. And there a physical relationship because the breaker is connected to the faulted line.

Absent known problems with the control or protection system, we expect the operator to assume those systems will work as designed.

But electrical-physical relationships can also change over the progression of time from the planning, operations planning, and real-time operating periods. For example, the zone of protection that was designed in the planning timeframe and then actually implemented may change as we move toward real-time operations. (That's why System Operating Limits and Interconnection Reliability Operating Limits revealed in the planning timeframe may have little merit in real-time operations.) Again, just as with other physical changes, the system operator needs to know the zone of protection has changed.

The simultaneous failure of multiple elements that are physically or electrically related may be likely and plausible, and therefore may be a credible contingency.

So expressing our reliability criteria in terms of "n-1" is not always correct. Rather, our reliability criteria should be based on being

[6] We are not talking about "common mode failures," where, for example, two generators share auxiliary equipment.

able to withstand the *next credible contingency*, which may include two or more elements.

Multiple-element contingencies considered credible in the planning timeframe may not be credible in the real-time operating timeframes, and vice versa.

Multiple contingencies. When the failure of one element causes the failure of others due to some electrical dependency that wasn't expected or designed for, we do not consider that to be a multiple-element credible contingency, and our expectations of acceptable performance are not necessarily the same as if it was. For example, consider a two-generator power station in Figure 3 where each generator, and its station service supply, is connected to separate busses that are electrically distant. While the two generators are physically adjacent, they are electrically separate and independent. We do not expect the failure of one generator to affect the other, or even the surrounding parts of the Interconnection. One could *imagine* this sequence of events, but it's not very likely because of the way these particular generators are connected to the Interconnection. This example shows how system planners manage risk by connecting G1 and G2 on separate busses electrically distant from each other. Therefore, the failure of one should not affect the other.

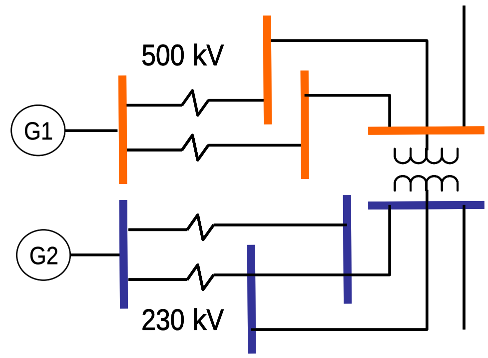


Figure 3 - By design, the operation of G1 and G2 are isolated from each other.

Therefore, in this particular example, the simultaneous failures of G1 and G2 is not a single multiple-element contingency; rather, these are multiple (two), single-element contingencies. If they had occurred at different times, they would be individual, credible single contingencies. But that's not the case when they occur simultaneously.

The simultaneous failure of multiple elements that are not physically or electrically related by design is not likely and therefore not a credible contingency. However, if those elements become physically or electrically linked, either accidentally or on purpose, their simultaneous failure could be a multiple-element credible contingency. Therefore, the system operator must know if that dependency exists.

Likelihood

So now the question becomes: Which kinds of contingencies are the most likely to occur and which are less likely? How does the likelihood of a contingency affect our planning and operation of the Interconnection? How do we want the Interconnection to respond to the most likely contingencies, and why and how do our expectations change for those contingencies that are less likely? The table on the right illustrates this point; it's not absolute, and we could add many more contingencies and then debate their relative likelihood of occurring. And there's a point at which the likelihood is so low that the event is not credible at all.

Contingency	Likelihood
Single transmission line or generator failure.	Decreasing ↓
Double-circuit failure on same tower.	
Single line failure + stuck breaker (delayed fault clearing)	
Trip of all multiple generators at the same plant.	
Failure of two transmission lines feeding substation	
Substation failure	

Likelihood as a function of design. From experience, and simple common sense, we know that single-element contingencies are considerably more likely to occur than multiple element contingencies because the generation and transmission system is designed to contain equipment failures through substation and generating plant design. Breaker configuration, protection logic, generating plant controls and station service are designed to prevent equipment failures from spreading to other parts of the plant or substation and cascading into multiple outages.

What's the worst contingency? The worst contingency is limited only by our imagination. But, for practical reasons, this isn't an open-ended scale. On the other hand, contingencies that we imagine are extremely unlikely still happen, and when we investigate those events may find that the "trigger" is more common than we thought. Again, experience will tell.

But there is no single transmission system design specification, nor do we propose there be one. While breaker-and-a-half substations are inherently better at containing equipment failures than ring-bus substations, they are also much more expensive. It may or may not be practical to connect multiple generators at the same plant to different parts of the transmission system. Therefore, multiple-element contingencies that may not be credible in some parts of the transmission system may be credible in others because of the difference in transmission system substation design or transmission line topology or generator connections. But differences in transmission design philosophy does not necessarily mean differences in customer reliability. It does mean the system planner, operations planner, and operator must know which contingencies are more likely, and which ones aren't, and be able to manage the risks of both.

External factors. External factors, such as weather, can quickly the increase the likelihood of a contingency (see **Figure 4**). For example, the failure of two separate transmission lines supplying the same substation is much more likely in the presence of thunderstorms. Indeed, such an event triggered the 1977 New York City blackout. Therefore, system operators may want to dispatch generation differently during these periods, and treat some multiple contingencies in the summer afternoon as likely and credible, even though they weren't likely that morning.

We won't spend more time on external factors, except to say they can change unlikely events into likely events, and therefore, into credible contingencies. And over a very short period.

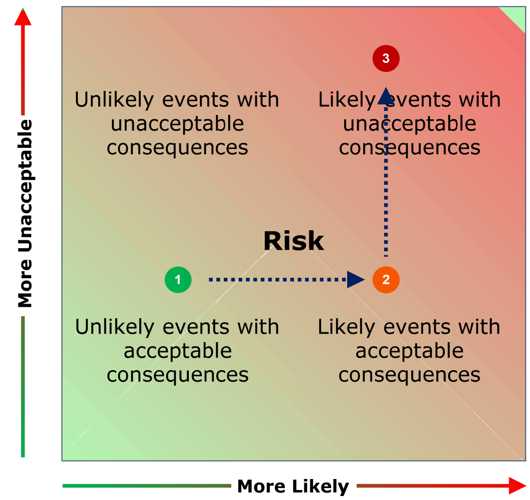


Figure 4 – An approaching thunderstorm can increase the likelihood of a fault caused by lightning (1→2). And heavy line flows could result in unacceptable consequences (2→3).

Re-preparation

Until now, we have implied that multiple contingencies are the *simultaneous* failure of two or more elements that, had they occurred at different times, would be two separate single-element contingencies. But how much time can pass before we make that distinction? Actually, there are three other questions we need to answer:

1. How much time *does the system operator need* to re-prepare the system to withstand the failure of the next piece of equipment, and
2. How much time *is the system operator allowed* to re-prepare the system to withstand the failure of the next piece of equipment, and
3. What is the *risk* during the re-preparation time?

We are not going to answer these questions in this document; rather, we pose them because the standards NERC writes must address all three.

Containment. We also understand that as contingencies involve more *elements* or *facilities*, our ability to contain them—to limit their spread—becomes more difficult, and as a result we accept the fact that the area affected becomes more extensive with potentially greater impact to customer service. We expect the effects of single element contingencies to be very localized to the point that only the customers who are directly connected to the element that failed will be materially affected.

At the extreme, multiple contingencies may disrupt Interconnection integrity and overload equipment, which could affect customers over a large area of the Interconnection.

So one of our objectives is to *contain* the effects of an event caused by credible contingencies to the smallest area possible. Table 2, which is by no means exact, provides the general idea. The relative containment of these events is not this absolute.

Event	Containment
Single-element failure	Less Contained
Line fault with delayed clearing	
Substation failure	
Simultaneous single element faults (multiple contingencies)	
Severe equipment overload	
Unable to maintain ACE	
Voltage or system instability	
Islanding (imbalance)	

Table 2 - This list provides a general idea on the relative containment of various events. The order will vary from system to system.

The August 2003 blackout is a good example of a lack of containment. A series of credible, single element contingencies that should have been completely contained spawned multiple contingencies, and a large part of the Eastern Interconnection lost its integrity.

The 1965 blackout is even more striking: a highly credible, single element contingency, which should have had no effect anywhere in the Eastern Interconnection, caused an immediate, widespread cascading outage affecting the Northeast U.S. and southeastern Canada. Of course, that event happened before NERC's time, and was the very reason we need reliability criteria and standards.

Therefore, our planning and operating criteria should be focused on preparing for and managing credible contingencies (those that are likely and plausible) as well as those critical contingencies whose consequences are unacceptable.

Summary

1. Credible contingencies are events (including disturbances and equipment failures) that are likely to happen.
   a. We consider the failure of single elements (a transmission line, a breaker, a generator) as a credible contingency.
   b. We consider the failure of multiple elements that are electrically "related" *and that experience has shown to be a likely occurrence* as a credible contingency. For example, a single-phase-to-ground fault plus a stuck breaker *may* be a credible contingency if experience has shown this multiple-element event to be likely.

2. Two or more dependent contingencies (that are electrically related) may, or may not be credible, depending on how we plan and operate the Interconnection.
   a. The corollary is that we plan and operate the Interconnection to remove the electrical dependency of separate contingencies and therefore contain their effects.
3. Two or more independent contingencies (that aren't electrically or physically related) that occur simultaneously are not necessarily double or multiple contingencies. They are two separate, simultaneous, contingencies. The fact that they occurred at the same time is simply unfortunate.
4. We have historically thought of our operating reliability criteria as being able to withstand an "n-1" event—that given some part of the Interconnection with "n" elements, we can reliably operate following the failure of any one of them. But given the many different kinds of credible contingencies, "n-1" is not always correct. Rather, our reliability criteria should be based on being able to withstand the next credible contingency, which may include multiple elements.

   Therefore, the system operator monitors the actual flows on its facilities and controls these flows so that they are within acceptable limits (System Operating Limits and Interconnection Reliability Operating Limits.) Keeping the actual flows within the SOL and IROL (and assuming those limits were calculated correctly) will help ensure the contingency flows (the flows that would result if the contingency occurs) will also be within acceptable limits.
5. The system operator must also posture, or "re-prepare" the system so that it is able to withstand the next credible contingency within a certain period of time[7].
6. Equipment that is already off line, either planned or forced, is not a "contingency." Contingencies are events that haven't happened. Rather, the actual or expected (in the case of planned outages) configuration is the starting point for any analysis in the operation planning time frames. We will explore this in detail in the Real-Time Period discussion.

[7] We won't define that "certain period of time" in this document. It would probably be defined in a reliability standard.

Acceptable Performance

The first two sections explained that, while we cannot prevent events from happening on the Interconnection, we can prepare for them. We do this by planning and operating the Interconnection so when events—*contingencies*—do happen, their consequences are acceptable. We explained this as “managing risk.”

Then we discussed the idea of *credible contingencies*, and explained that these could be single- or multiple-element. And that some contingencies were more *critical* than others.

As contingencies become more severe, their effects can become harder to limit or contain, and we will expect the Interconnection to lose its integrity if the contingency becomes severe enough. However, we also expect those kinds of contingencies to be highly unlikely.

The third reliability concept ties contingencies to acceptable consequences, and then defines those consequences in technical terms as the *acceptable performance* of the Interconnection. Table 3 on page 29 shows these relationships.

At this point, we can define acceptable performance following a credible contingency as: 1.) maintaining Interconnection integrity, and 2.) protecting Interconnection equipment[8] from severe damage.

Interconnection Integrity

The reliability of the Interconnection depends on its continuous network connectivity. Events that unravel the Interconnection, such as those in August 2003, may start out slowly, and then escalate to very fast (fractions of a second) cascading failures that cannot be manually stopped once they enter their dynamic phase. NERC’s reliability standards are aimed at preventing cascading outages (another way of expressing the goal of “maintaining Interconnection integrity”) by requiring that Interconnection voltages and phase angles remain stable following credible contingencies. So, stability is an important part of our definition of “acceptable performance.”

Protecting Equipment

In addition to maintaining Interconnection integrity, NERC standards also require that equipment remain loaded within its “applicable ratings” following credible contingencies. There are really two goals

[8] Generally we are referring to the “bulk power system” equipment, but may include equipment at lower voltages that support BPS operations.

embedded in this requirement. First are the short term effects when equipment that loads to the point of catastrophic failure initiates cascading outages, instability, and loss of Interconnection integrity. Second are the long-term effects of the failure of equipment that takes months or years to replace. It's this latter goal, protecting equipment, that is only implied in NERC's standards, and should be clearly stated.

To do that, we need to look more closely at equipment ratings, and how the system operator can intervene to bring equipment loading under control to prevent severe damage and avoid endangering the public.

Definitions: Facility, element, equipment. NERC defines "facilities" as combinations of "elements." (see Figure 5) This document refers to single- and multiple-"element" contingencies, and stresses the importance of protecting "equipment," but doesn't mention "facilities." NERC defines "equipment rating," but not "equipment," and defines "facility ratings" in terms of the ratings of the equipment making up that facility. Indeed, when it comes to ratings, we usually talk in terms of "equipment ratings," not "element ratings." Table 1 in TPL-001 refers to "applicable ratings," which it defines as the

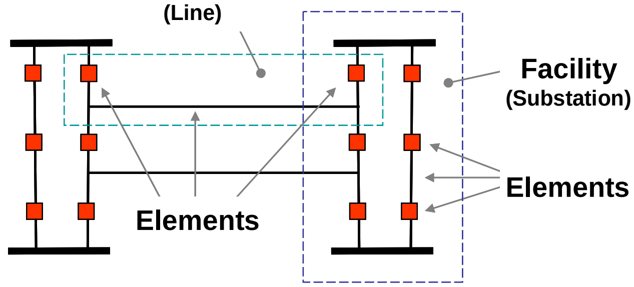
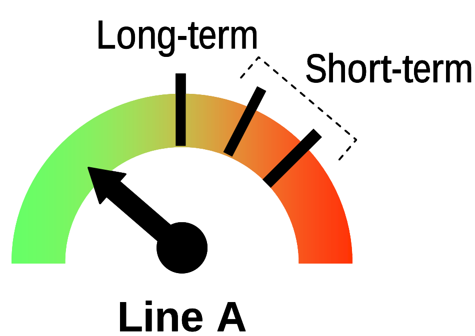


Figure 5 - Facilities are combinations of elements.

> "... applicable Normal and Emergency facility thermal rating or voltage limit as determined and consistently applied by the system or facility owner. Applicable ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings."

This definition implies that ratings are also a function of time, but more explanation is needed to understand how much time the system operator has to reduce the flow (or voltage) on equipment from its Emergency Rating to its Normal Rating.



This section will use the term "equipment ratings," recognizing that ratings could refer to either individual elements or facilities. And recall that we are after two goals: 1.) maintaining Interconnection integrity, and 2.) protecting equipment.

Long-term Rating. Quite simply, the long-term rating sets the limit at which the equipment can operate without appreciably reducing its life expectancy.

Short-term and Emergency Ratings. We would logically infer that the system operator must keep all transmission equipment within its long-term ratings. But there's actually some leeway here because equipment can usually be loaded above its long-term rating for a limited time, called its "short-term rating." And that short term could provide enough time for normal load patterns or operator action to bring the loading down to the equipment's long-term rating.

The short-term rating is a function of both MW flow and time. A transmission line may have a 500 MW long-term rating, a 650 MW two-hour rating, 700 MW one-hour rating, and an 800 MW 30-minute rating. The equipment owner could set 15-minute ratings and even shorter duration ratings at which the equipment could operate for only minutes without severe damage. Some might call these very short duration ratings "emergency ratings."

The point is that "acceptable performance" following a contingency may mean that some equipment is loaded to its short-term rating, and the system operator actually has time to intervene or judge that the load and generation pattern will return the equipment loading to its long-term rating. This will be important to our later discussion on system limits.

We expect the Interconnection to maintain its integrity and all equipment to operate within its long-term ratings all the time. Following a credible contingency, we expect all system voltages and phase angles to settle into new, stable positions. Equipment may load to its short-term rating, but the system operator will manually intervene if necessary to reduce that loading to the long-term rating.

Table 3 - Typical examples of credible contingencies and acceptable performance. The acceptable performance is also a function of the severity of the event.

Event	**Acceptable performance**
Maintaining Interconnection Integrity	
Credible Contingency – Single element failure	Voltages remains stable and within safe operating limits, and phase angles remain stable everywhere.
Credible Contingency – Multiple-element failure	Voltages immediately surrounding the contingency may become depressed, but remain stable. Phase angles remain stable everywhere.
Unable to maintain area control error within limits	The system operator will take whatever action is needed to return the balancing area ACE to within control performance limits. Tm < control performance limits. Voltage and phase angles remain stable everywhere.
Protecting Equipment	
Equipment above long-term rating but less than emergency rating	Tm < equipment short-term rating time limit.* The system operator will take whatever action is needed to return the equipment to its long-term rating. This may include manual load shedding.
*Note: Tm is the time limit for returning the system to within a system operating limit or interconnection reliability operating limit. It is not a compliance violation measure.	

In general, we manage risk by translating the general terms of the likelihood and severity of an event and the consequences we are willing to tolerate into the technical terms of acceptable Interconnection performance and system limits that we measure as MW and MVar flows, voltages, phase angle differences, system stability, area control error, and so forth. Judgment and experience, as well as common sense, tell us that less likely and more severe events are more difficult to contain and when they occur we expect the Interconnection to perform differently than it would from a simple and local equipment failure. The outer bound we never want to cross is the loss of Interconnection integrity or severe equipment damage resulting from contingencies that are likely to occur.

Now we've reached the point that we can state NERC's planning and operating criteria as:

Definition of "Adequate Level of Reliability." These four sentences are included in the definition of "Adequate Level of Reliability."

We plan and operate the Interconnection:

1. **To maintain its real-time operating integrity,**
2. **To ensure that credible contingencies result in acceptable performance,**
3. **To protect the generation and transmission equipment from severe damage, and**
4. **To enable the system operator to restore the Interconnection's integrity if it is lost.**

Summary

1. Our reliability criteria relates credible contingencies to acceptable performance.
2. In general, acceptable performance means 1.) maintaining Interconnection integrity and 2.) protecting generation and transmission equipment from severe damage.
3. The degree to which customer service is interrupted is a function of the likelihood, severity, and containment of the contingency.
4. Our reliability studies (planning and operations planning) reveal the Interconnection's *predicted* performance following various events.

Timeframes

Though we usually think of *operating* criteria as distinct from *planning* criteria, the two are very closely linked because what the system planners design, the system operators must operate. But we cannot simply state the obvious without explaining and understanding the relationship—or more precisely, the interrelationship—between system planning and system operations. We will start with the diagram below.

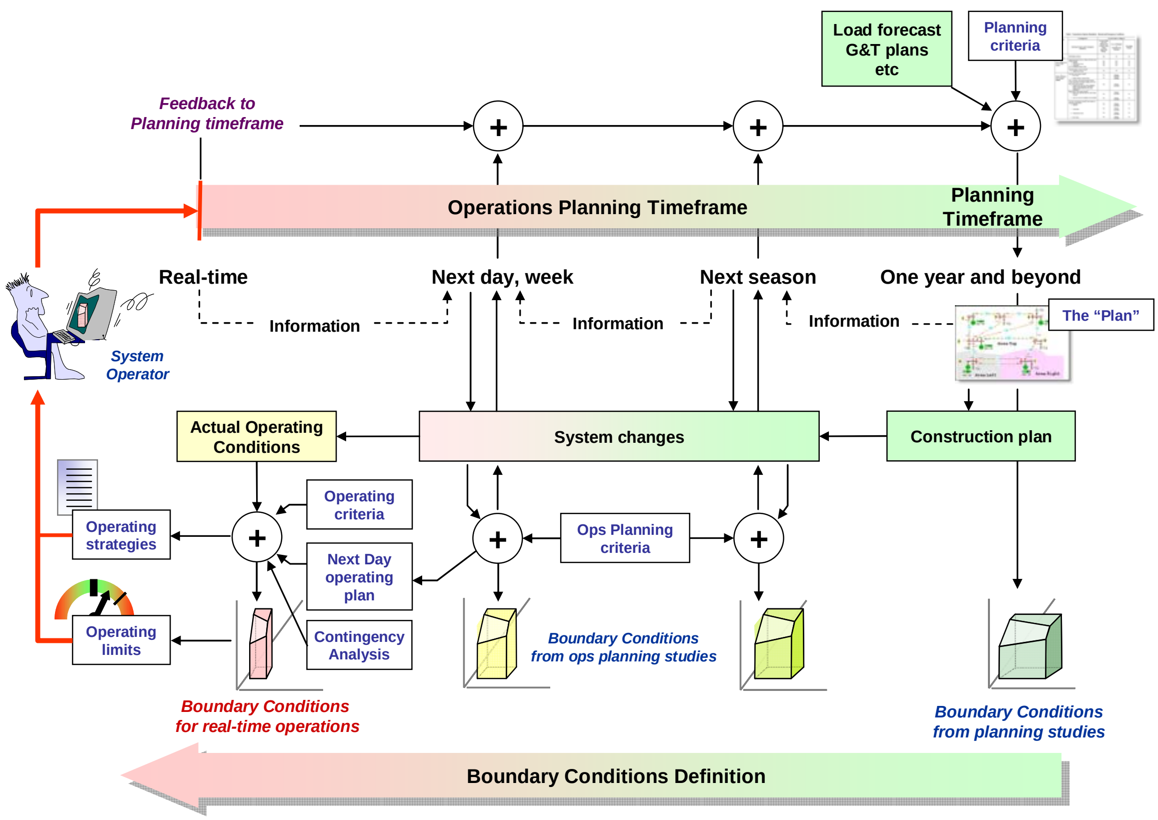


Figure 6 - Timeframe overview.

We immediately see two major progressions that link system planning and system operations. First, there is the **timeframe** beginning with **real-time operations** (right now!), progressing through the **operations planning** period that covers the next hour, day, week, month, and season, and extending into the **planning** period of one year and beyond. These periods describe the three **timeframes** during which we study and operate the Interconnection using planning, operations planning, and operating criteria. The second progression shows the refinement of the **boundary conditions** as our studies move from the planning timeframe more than one year away, through the operations planning timeframe that ends the next hour, and finally arriving at the point of real-time operations where we have derived the **operating**

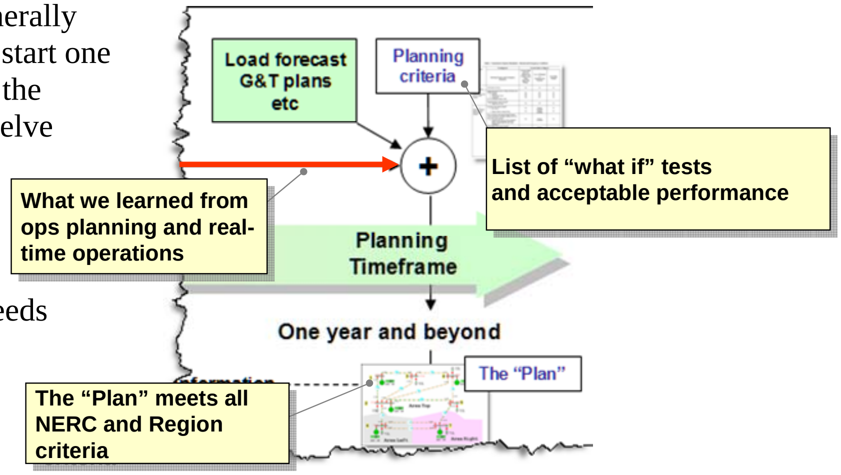
limits for the system operator. In each of these approaching timeframes, we know more and more about the generation dispatch, demand, interchange, and transmission topology as we move closer to the present. Within these timeframes are several eddies of **feedback** and **feedforward** information links regarding system construction and modifications, studies, and real-time information display (situation awareness) that tie operations and planning together.

Because our objective is to be able to operate the Interconnection so that credible contingencies result in acceptable performance, protect equipment from severe damage, and restore the Interconnection after a blackout, we must design and build the system so that it can achieve this objective. Our success in planning an Interconnection we can operate reliably "right now" and that's robust enough to accommodate different load patterns, equipment availability, and market pressures rests largely on the assumptions we make about our customers' electricity needs in the future and what we learn from operating the system day-by-day. That means we need solid information linkages in both directions between the planning and operating timeframes.

We could start this discussion at any point along the timeframe, but we found it best to begin with the **planning timeframe**. Of course, we know everything happens "now"—system planners are planning the system "now." But what they are planning for is what the Interconnection will look like a year or more from now. So let's start with how they do that.

Planning Timeframe

From a practical standpoint, we generally consider the planning timeframe to start one year from now and extend as far as the utility's business model allows. Twelve months is, more or less, the earliest time at which utilities can begin building or significantly modifying parts of their transmission systems to meet the needs of the system operator[9].



Developing the "Plan"

Planning the transmission system requires four major ingredients:

1. Load forecast,
2. Existing generation and transmission systems along with those future plans already in place,
3. What planners learn from system operators about the performance of the existing system, and
4. The planning criteria, which lists the acceptable performance of the Interconnection following "what if" tests of credible contingencies.

Load forecast. System planners develop their load forecast in a variety of ways using a variety of assumptions, econometric models and statistical information. We will not cover these details of forecast models in this document.

Generation and transmission plans already in place. Depending on where we are in the planning horizon, the system planner will need to accommodate those generation and transmission facilities that are either committed or are in various stages of construction. These plans include independent power plants, and power plants and transmission lines in other electrically related areas.

What planners and operators learn from each other. An important information link that some find missing, or at least weak, is one that conveys the system operators' experiences to the system planners, and the planners' assumptions and knowledge to the operators. How do operators really operate the system, and what do planners assume is

Planning studies and "uncertainty." Uncertainty is a function of how far out in the future we are looking and for the purposes of planning studies is boiled down into "Simplified Assumptions".

How we deal with outcomes of studies that use these assumptions is a function of sensitivity of the study results to changes in the assumptions as we approach real-time.

This sensitivity may need to be translated into a margin that has to be applied to the resulting boundary condition or ultimately a limit.

[9] Twenty-four months may be more realistic for some transmission and generation equipment.

acceptable performance? In particular, system planners benefit from learning 1.) which contingencies are likely, and therefore credible, and 2.) how the Interconnection actually performs following real contingencies, while the operators need to understand the planners' expectations.

What's *really* credible

As we explained above, credible contingencies are events that are plausible and likely to occur, and that likelihood can vary in different parts of the same Interconnection, and at different times. Utilities in west-central Florida must consider lightning-induced faults as very likely, credible contingencies in the middle of summer, but these are less likely contingencies in, say, British Columbia. A generator failure in a large downtown area may be of little concern at 2 a.m., but could be a critical contingency if it causes the voltage to sag dangerously at 2 p.m. if system operators aren't properly prepared.

System operators are witnesses to the events that really happen. They learn from experience what's likely and what isn't. As we explained in previous sections of this document, experience over time is critical to understanding what contingencies are credible, especially those that involve multiple elements.

Simultaneous events that may have seemed unrelated in the planning timeframe may, in fact, be tied to each other because of the actual, real-time configuration of the transmission system or current load pattern that create dependencies, either intentionally or not. Do lines A and B tend to fault at the same time? Are certain parts of the transmission system particularly sensitive to voltage decay? Are generators 1 and 2 more susceptible to instabilities? These are vital bits of data that system planners need to true up their models and add to their list of credible contingencies for their study cases. And a very important question: Does the system planner have a **wide enough view** (see text box at right) to recognize dependencies across different parts of the Interconnection? This is why regional and interregional studies are critical to planning an Interconnection that can maintain its integrity.

How wide is a "wide area?" This is one of the questions often asked, especially with respect to real-time operations. One answer is: As wide as will consider credible contingencies that are electrically or physically dependent.

Actual performance

Equally important to system planners is the actual performance of the Interconnection to these contingencies. Do the operators observe slow oscillations in Interconnection frequency or area voltage without any initiating event? Does the Interconnection frequency recover after a plant trips off line. Does the voltage sag or transformers overload, or do multiple breakers trip after a 500 kV tie opens? System planners need to know what actually happens after an event, whether credible or not, then compare this actual performance with the predicted performance, and then decide whether they need to adjust their plans or their models, or provide the system operators information on what actions are available (and acceptable) to mitigate a system operating limit violation.

We will find a similar feedback (or feedforward) loop between the operations planning and planning timeframe as well.

Projected performance

There is a related term—projected performance—which is what our planning and operations planning studies project will happen following a particular contingency. For example, if the system planner studies the simultaneous failure of all high-voltage lines into a metropolitan area, studies will probably predict a voltage collapse or instability. This may be a nuance, but it's important to understand that acceptable performance is the term we use to define how we want the system to respond. Projected performance is what our studies reveal the outcome will be. It's the system planner's job to make sure that the projected performance of the "as planned" transmission system will be acceptable. In a similar fashion, it is the operations planner's job to make sure the "about to be real-time" transmission system will perform acceptably. In the next section, we will explain how the system planner and operations planner do this.

Planning Criteria

For many years, NERC published collections of the regional planning criteria (see Bibliography), and from those criteria, developed the current planning standards—specifically, the TPL series. Within TPL-001 we find "Table I. Transmission System Standards – Normal and Emergency Conditions," which brings together many of the concepts we have been discussing in this document. (See the following two pages). Table I lists the credible contingencies in two categories, B and C, of decreasing likelihood and increasing severity, and the acceptable performance for each.

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

Expected Performance

Credible Contingencies

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

For example, we find in Category B the planning requirement that if a single line or three-phase transmission fault occurs and the breakers operate normally (the credible contingency the planner is testing), the transmission system is supposed to remain stable with all equipment loaded to within its normal operating limits, and with no load shedding or cascading outages (the acceptable performance). (However, we also note that while the “Loss of Demand or Curtailed Firm Transfers” column is marked “no” for these contingencies, footnote (b) qualifies that notation. For instance, the customers connected to the faulted equipment may lose their service.)

In Category C we find more severe credible contingencies. For example, we plan the transmission system so that following a bus section fault, the transmission system will remain stable. However, in this case, we accept some controlled load shedding. In other words, the performance we accept from the Category C events is different than from the Category B events.

The Category D events are relatively unlikely, and their consequences so severe, that we may not be able to reasonably build or operate the transmission system to recover from them. We consider these to be very rare contingencies.

For example, a three-phase fault with delayed clearing can depress the surrounding voltage deep enough to trip generating plants which causes a loss of real and reactive power that depresses the voltage further and over a wider area, and so on. That doesn’t mean system planners or operators ignore these events; rather, they study them to predict the Interconnection's performance - its margins and sensitivities - and evaluate potential mitigation plans against the probability and severity of the event.

Special considerations. Some transmission planners have devised variations on these categories to consider transmission configurations, limits, and reliability requirements that are unique to certain areas of the Interconnection. For example, some transmission planners design their system to recover from the failure of two transmission lines on adjacent rights of way because experience has proven that to be a credible contingency. As we explained in the previous section, a credible contingency in one part of the Interconnection may not be credible in another, or credible today and not so tomorrow.

The next section on Operations Planning will explain the relationship between the design categories in this table and the contingency analyses that utilities perform in the Operations Planning period.

The Deliverables

The reliability criteria provides the foundation that, along with the load forecasts, generation and transmission plans already in place, and what we learn from system operations, helps the system planner produce two things:

5. The *construction plan* that the planners hand off to whoever designs and builds the transmission system and generating plants, and
6. The *boundary conditions* from the planning studies.

Construction Plan

The construction plan provides target dates for new facilities coming into service, and may require some facility outages to accommodate the new construction. Both the new facility in-service dates and the existing facility outage schedules are critical to operations planners in developing system operating limits for the upcoming time horizon.

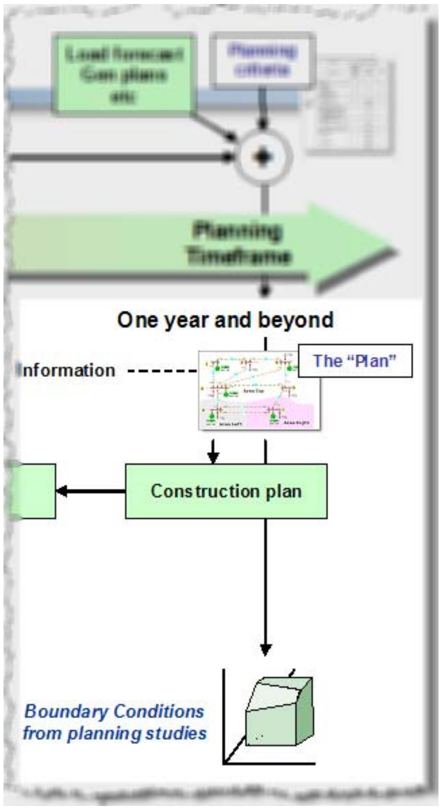


Figure 7 - The deliverables from The Plan.

Boundary Conditions

The boundary conditions are a combination of the set of assumptions that the system planner (or operations planner) uses in his studies along with the observation of acceptable performance following the test of credible contingencies (and even those that aren't credible as the planner may choose). Boundary conditions typically have several dimensions, such as system load, transmission configuration, generation, and levels of scheduled interchange.

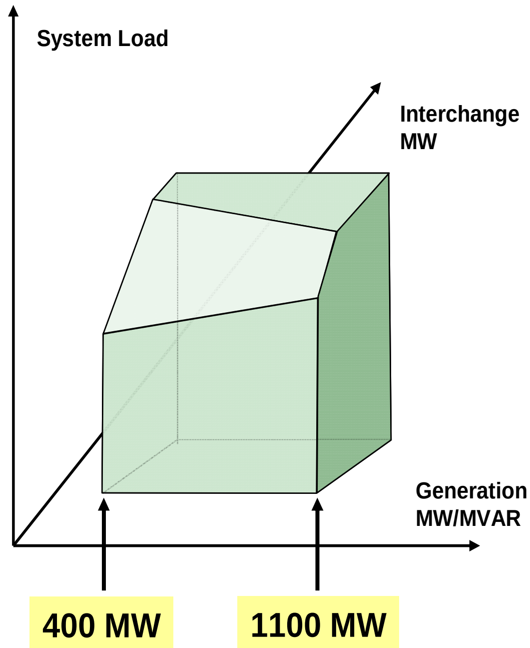


Figure 8 - The boundary conditions are the set of planning or operations planning assumptions that, when studied, produce acceptable performance. In this example, the generation boundary conditions range from 400 MW to 1100 MW.

System planners determine these boundaries by performing "what-if" tests (studies or simulations) of a set of credible contingencies at different levels of generation dispatch (real and reactive), demand, and interchange, and with various transmission configurations, and then observing whether the Interconnection exhibits the performance we consider acceptable.

Points at which the generation dispatch, load, interchange, or transmission configuration were studied and yield acceptable performance are within the boundary conditions.

We can picture the boundary conditions as a box (Figure 8) whose sides represent the range of study assumptions that produced acceptable performance[10]. From the system operator's perspective, one could say that if a credible contingency were to occur when operating within those boundary conditions, the Interconnection would perform acceptably.

Let's assume the system planner studies all credible contingencies with generation ranging from 400 MW to 1100 MW in 100 MW steps. At 1100 MW, the studies show the Interconnection will perform acceptably after a credible contingency. With generation at 1200 MW, the system planner finds that some credible contingencies did not result in acceptable performance. Therefore, generation at 1200 MW is definitely outside the boundary conditions.

But what about generation levels between 1100 MW and 1200 MW that weren't studied? **Because we don't know how the system would perform, those points are automatically outside the boundary conditions.** We may interpolate between these points and assume that

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[10] The boundary conditions illustrated in Figure 9 represents just a few of the study parameters. In reality this can be a very complex, multifaceted and multi-dimensional diagram.

generation levels between 400 and 1100 MW are safe[11], *but we cannot extrapolate* the boundary beyond 1100 MW because we don't know for certain that generation beyond that point will meet our Interconnection performance expectations until we have completed a study to prove the generation level as safe.

Therefore, the boundary conditions for generation would be from zero to 1100 MW—the greatest value that was studied *and* shown to result in acceptable performance.

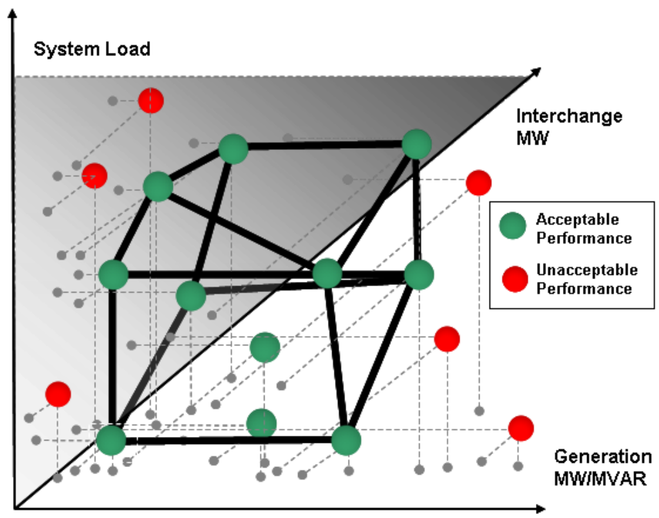


Figure 9 - "Scatter" plot of planning scenarios.

Connecting the dots

Of course, system planners cannot test *every* operating scenario, but they can test a collection of those that he believes are reasonable. For example, the system planner will input a load pattern and generation dispatch to simulate a hot summer day sometime in the future and anticipated interchange arrangements, then simulate various credible contingencies, and analyze the resulting performance of the transmission system. The planner will vary these parameters, and run similar studies that simulate typical daily light-load conditions, spring and fall load and generation patterns, winter peak demand conditions, and different levels of interchange.

Every planning study that yields acceptable performance defines a part of the boundary conditions. But a study that shows the system will probably fail following a credible contingency is outside the boundary condition. So are conditions beyond the study limits the system planner never considered.

Conducting many studies will yield a scattering of scenarios that we could imagine as points on a 3-d graph whose axes represent the variables, say, equipment limits, generation dispatch (a function of demand), and interchange, respectively. (Figure 9) The system planner can add other parameters, but we can only visualize three dimensions, so we'll just use these.

The green dots in the figure are the scenarios that the system planner tested against the credible contingencies that resulted in a successful

How many studies? We cannot expect system planners to study *every* likely condition. For example, transmission systems deeply embedded in the Interconnection could model many times more topology and interchange cases than systems on the periphery. To compensate for this, planners may use "proxies" or simulate multiple variables to provide insight into the many scenarios they cannot physically study.

[11] It isn't possible to study every point between 400 and 1100 MW. Instead, the studies are run at discrete intervals. We discuss this in the section, "Connecting the Dots."

outcome—the planned transmission system met the planning criteria. The red dots are those scenarios that didn't.

We can then "connect the dots" (the green dots in the figure) and reasonably assume that operating this planned system *at or between* those points, in any dimension, will be safe. That is, we can interpolate between the points our studies show are OK. But, *we cannot extrapolate* beyond these points because we didn't study those scenarios and don't know what will happen following a contingency, credible or not. The system may operate just fine. But we simply don't know.

We could give this diagram to the system operator right now and tell him, "The system we planned and expect to construct will operate reliably as long as you keep the generation, equipment loading, and interchange at or between the green dots. Those are your boundary conditions for the transmission and generation configuration in these planning studies." However, the system operator does not operate to the boundary conditions; rather, he operates the system to stay within flow limits on specific lines, generator output limits at power plants, and voltages at substations. These are the operating limits, which we will cover shortly.

Contingencies in the Planning versus Operating Horizons

The collection of contingencies system planners consider credible when performing their planning studies is usually different than the collection of "next credible contingencies" that system operators must be ready to deal with. System planners generally assume all transmission system elements are in service and connected as planned. They also study the system at specific load levels. The resulting plan is one that provides acceptable performance across a range of uncertain future conditions. System operators are faced with the actual transmission topology and generator dispatch at hand, and the next contingency may not be among the events the system planner studied. The system demand will most likely be higher or lower, transmission equipment may be forced out of service, and planned outages may deviate from maintenance schedules set months earlier.

Summary

1. Planning criteria comprise lists of credible contingencies and acceptable performance.
2. Utilities may need to establish planning criteria that cover additional contingencies that are credible or more critical for them, but may not be for others.

3. Planning studies use the planning criteria to yield both a construction plan and a set of safe operating scenarios.
4. Plotting the safe operating scenarios shows the boundary conditions from which the operating engineers derive a set of operating limits within which the system operator must operate the transmission system.

Operations Planning Timeframe

There usually isn't a "bright line" between the Planning Timeframe and the Operation Planning Timeframe because there may be no discrete hand-off, so to speak, of information or plans in either direction. Rather, the operations planning timeframe looks over the next several months to provide the system operators (including the reliability coordinators) with their first glimpse of what the as-built system and its associated boundary conditions will look like as real-time approaches. (Figure 10) The Operations Planning timeframe should more accurately incorporate the state of the economy and near-term expected weather conditions into the forecasted load patterns and bilateral transactions. Therefore, as we move toward real-time the boundary conditions change to reflect the shifts from our longer-term design and construction strategies to operating strategies that must be developed and implemented over the next few months, weeks, days, and hours to address the system as it unfolds.

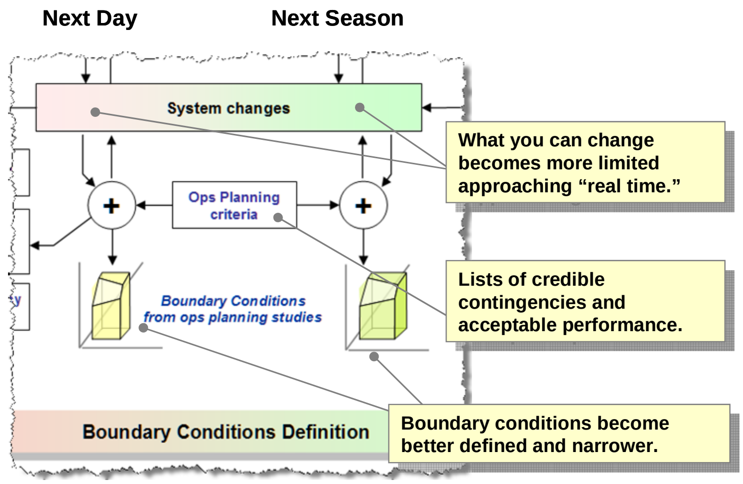


Figure 10 - As we move toward real-time ("now") our ability to operate within the Boundary Conditions shifts from the longer-term design and construction strategies to operating strategies.

To describe the operations planning timeframe we need to understand its dynamics and, as always, manage our expectations. Over the next 12 months, utilities can repair, add, and change out equipment and revise their protection schemes. Their generation and transmission construction schedules come into sharper focus. But generating stations in their early days of construction won't be on line, and cleared rights of way won't sprout transmission lines during this period. This means the boundary conditions we formulated in the planning timeframe are narrower in the operations planning timeframe to reflect the generation and transmission system "that the operators will operate." Therefore the operations planning time frame must consider 1.) those facilities that are in service today, plus 2.) those facilities from the construction plan that we can *reasonably expect* to be in service over the next 12 months or less, and 3.) long-range maintenance schedules.

Tests of credible contingencies

The kinds of credible contingencies (single element, multiple element) and the corresponding acceptable performance of the transmission system that comprise the **Operations Planning Criteria** should generally be the same through all operations planning and real-time operations timeframes, though we would expect the contingencies themselves to change to reflect the evolving topology of the system. As we move from the next month to the next week to the next day, the study assumptions become increasingly constrained by the realities of what lies ahead. (See Figure 13) For the same reason, the control actions available to the system operators and reliability coordinators become more limited and more well-defined. Therefore, some contingencies will become more critical and some less.

Moving Through the Operations Planning Time Frame

Next season, next months. Over the next several months, system engineers study different demand patterns and transmission configurations. They true up their real-time contingency analyses models, conduct stability studies, establish the boundary conditions for a series of specific possible configurations and develop base case limits for adjusting their nomographs, including voltage and reactive schedules. They know more about planned and forced generator and transmission outages, but there is still considerable “wiggle room” to allow adjustments. Most important, they have a better grasp of which contingencies might become *credible* in the operating time frame.

Who perform the studies?

The personnel who perform operations planning studies may be a part of the operations engineering staff or from the system planning staff, or both, depending on how far ahead the studies look and how the organization is structured..

Next week. Looking into the next seven days or so, system engineers, operators, and reliability coordinators should have a better grasp on the load forecast, generating unit commitment (what is scheduled to be on line), availability (what can be put on line, and what can’t), transmission configuration, voltage schedules, and scheduled interchange. These variables are inputs to the development of the operating limits and variety of strategies that become available to the system operator to keep the transmission system within those limits in real time.

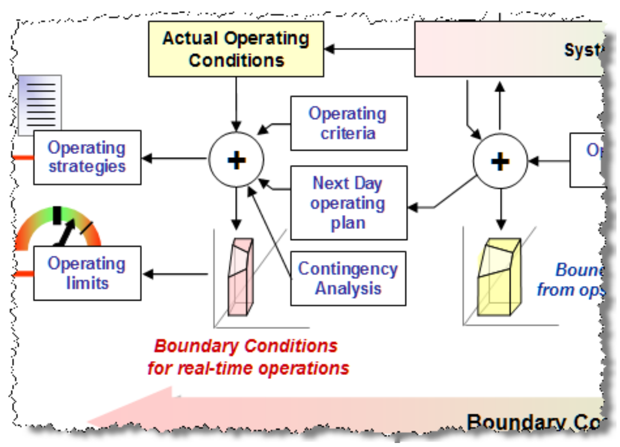


Figure 11 - The Next-day operating plan provides the basis for the real-time operating strategies.

As part of these operating strategies, the system operator or reliability coordinator may ask (or order, depending on the practicality and effectiveness of other options) generator and transmission owners and operators to defer generator and transmission maintenance. But it wouldn’t be reasonable to expect a generator to be on line next week when it’s in pieces on the turbine deck today undergoing a major overhaul.

Next Day. As the operations planning timeframe approaches real-time, the system operator has fewer options for keeping the transmission system within is operating limits. The system engineers and operators now develop the next-day operating plan (Figure 11) that will be taken into real time. This next-day plan includes the following elements (as a minimum):

- Load forecast
- Unit commitment (or resource plan) and resource availability information,
- Transmission configuration (including schedule of planned outages),
- Reactive support (may related to both resources and transmission equipment), and
- Pre-defined operating plans to address any pre-identified post-contingency limit violations
- Interchange schedules

These six elements provide the options for developing the strategies that the system operator can use to 1.) react to the next credible contingency (or worse) and keep the transmission system within the system operating limits, 2.) quickly mitigate system operating limit violations should the transmission system stray outside those limits, 3.) reposition the system to meet the next credible contingency, and 4.) restore the system following a blackout.

Of course, the system operator always has the load shedding option which he will use if there is no other way to keep or return the transmission system to its long-term operating limits quickly enough either pre- or post-contingency.

Summary

1. The “what-if” tests of credible contingencies and the corresponding acceptable performance of the transmission system that comprise the Operations Planning Criteria should be the same through all operations planning and real-time operations timeframes.
2. As we approach the next-hour, the system operator sees a clearer picture of what he will be operating in real-time.
3. The options for mitigating system operating limit violations become more limited, or they may become broader, depending on the operating conditions at the time.

Real-time Operations Timeframe

The term "real-time operations timeframe" seems an odd expression because real-time is what's happening right now. But we really need to think of "real-time" as now plus the upcoming hour for which the system operator knows the operating limits and strategies for operating within those limits.

As we then move closer to real-time operations, we will know better which operating limits will depend on network (physical equipment) improvements and changes that were assumed in the planning and operations planning timeframes, and which will now require operating solutions.

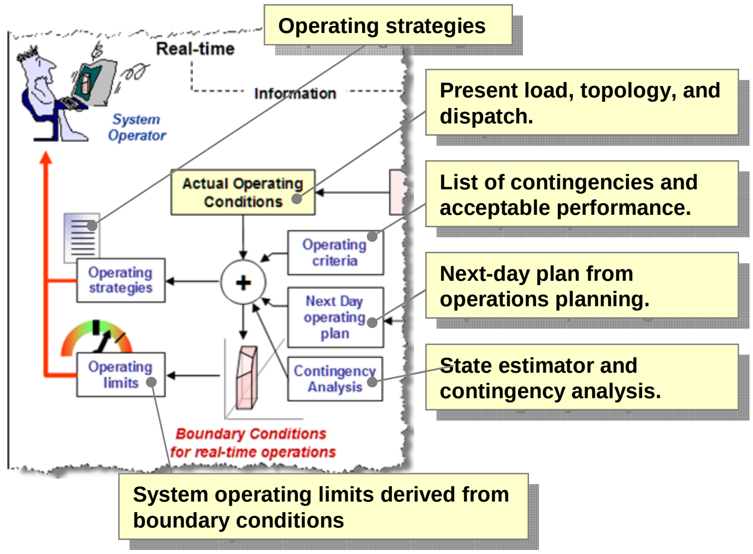


Figure 12 - The operations planning timeframe provides a day-ahead plan that should reasonably ensure that the system operator has the strategies in place.

Operating strategies

The operations planning timeframe provides the system operator with a next-day operating plan as well as the strategies available to keep the transmission system within its operating limits. Examples of these strategies include generator commitment and dispatch ranges (MW and MVar), availability of controllable loads, capacitor and reactor status, voltage schedules, arrangements with other systems for generating reserves, options for repositioning the system (mitigation) when violating system operating limits, and so on.

Operating Limits

We now need to tie the concept of boundary conditions—the specific set of study assumptions and associated outcomes that resulted in acceptable Interconnection performance—to the *system operating limits* within which the system operator must operate the system.

At first glance, it would seem that the boundary conditions and operating limits are the same. This is not necessarily true.

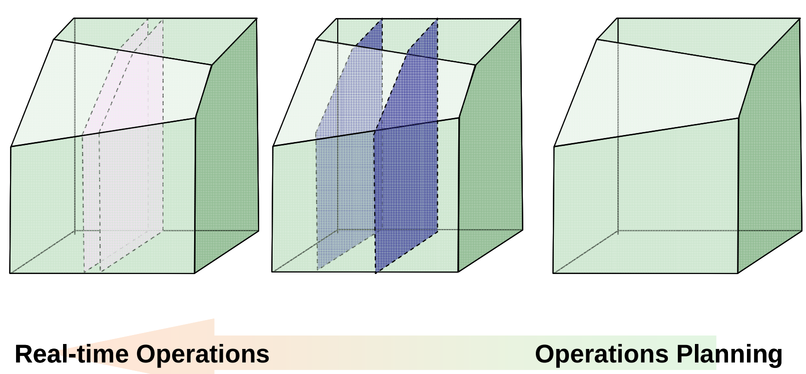
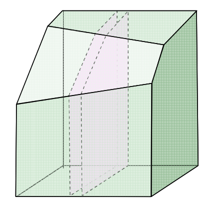


Figure 13 - The approach to real-time narrows the system operator's assumptions.

As we move from the planning timeframe through operations planning and eventually real time operation, we have a clearer picture of the day’s (or upcoming hours’) demand, dispatch pattern, and interchange levels, transmission topology, etc. In other words, as we become more certain of the expected system conditions, the boundary conditions tend to “shrink” to reflect fewer assumptions and available options (Figure 13). The operating limits are then derived from these newer and more realistic boundary conditions and expressed in terms of flow limits on specific transmission lines or corridors, reactive requirements at certain substations, and generation levels at specific power plants so that the Interconnection is prepared to perform acceptably following a credible contingency. (Figure 14)

The system operating limits are derived from the boundary conditions, and specify the ranges of line flows, system voltages, and generator loading that must be followed to ensure that credible contingencies result in acceptable performance.



Under certain circumstances, system operating limits can represent a range of conditions where it is acceptable to operate. For example, studies in the planning time frame may show the transmission system will reliably support an import of between 0 and 1100 MW on the boundary conditions on the “interchange” axis. But the operations planner may find that the generation dispatch or topology of the transmission system may allow imports up to 1500 MW.

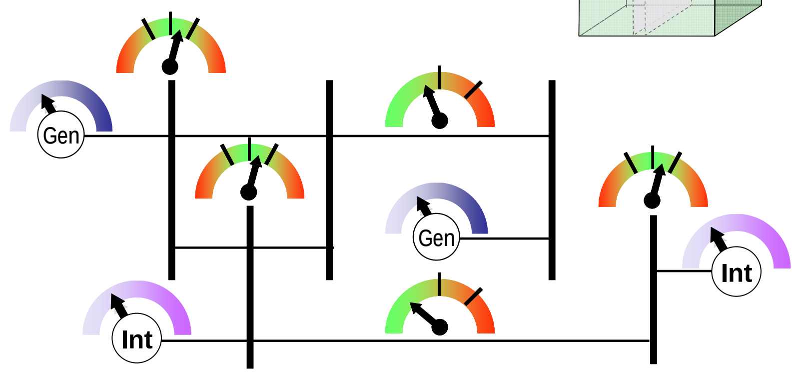


Figure 14 - The system operating limits are derived from the boundary conditions developed in the operations planning timeframe.

Operating limits after a contingency

Once a contingency occurs, the boundary conditions may change because the generation dispatch, transmission topology, or interchange flows may be quite different. It therefore follows that these new boundary conditions may require the system operating limits be recalculated. Doing otherwise would mean the system operator is “operating in a place he hasn’t studied” with operating limits that may not be valid.

Therefore, valid operating limits are those that are based on the studied boundary conditions. The system operators should not simply make up operating limits or set those limits empirically without specific knowledge of the studied conditions and the phenomena they are trying to protect against.[12]

Therefore, system operators must operate "where they have studied" so they will know where they may land following a contingency. This means they may need to take certain actions to reposition the system into a state that has been studied and shown to result in acceptable performance following a credible contingency.

On the other hand, some would argue that the studies can be conducted months ahead of time using a broad range of different transmission topologies, generation dispatch patterns, and interchange levels. The system operator would then use the operating limits that closely matched the study assumptions or maneuver the system to one of the study scenarios. This depends, in part, on the type of limits, system complexity and margin, or "head room," between the limits and expected system conditions. Generally speaking, the more predictable the system's performance, and the more head room available, can reduce the need for real time comprehensive studies to cover the range of operating conditions.

Summary

1. System operating limits are based on the boundary conditions, which are the set of study assumptions that resulted in acceptable Interconnection performance. While the boundary conditions are not the same as the operating limits, they do validate those limits.
2. Therefore, operating beyond the operating limits is either:
    a. "Operating where you haven't studied," which means the system operator doesn't know whether the Interconnection will perform acceptably following a credible contingency, or
    b. Operating where studies showed the Interconnection will not respond acceptably following a credible contingency.
3. The boundary conditions represent the set of planning or operations planning assumptions that, when studied against a set of credible contingencies, produce acceptable Interconnection performance.
4. The parameters (equipment flow and voltages) selected from the calculations that provide the key indication of the boundary conditions are System Operating Limits and Interconnection Reliability Operating Limits.

[12] See November 4, 2006 UCTE Blackout

Categories of operating limits and mitigating operating limit violations

Looking into the next few hours, the system operator has a clearer picture of the operating conditions that will materialize in real-time. The system operator knows the generation dispatch, load pattern, interchange, and transmission configuration that he is about to face. He should know the voltage schedules and reactive requirements. He also knows the system operating limits that were derived from the boundary conditions determined through contingency analyses in the operations planning timeframe. Now his job is to keep those dials and meters within the ranges that keep the system within those boundary conditions. The operator has an operating plan and list of operating strategies to help him do this. He also relies on his own judgment and knowledge of the transmission system gained through years of experience and training.

Operating limits fall into two categories—**System Operating Limits** and **Interconnection Reliability Operating Limits**—with subcategories for both.

Table 4 - This table summarizes the main characteristics and differences between System Operating Limits and Interconnection Reliability Operating Limits.

	System Operating Limits				
			Interconnection Reliability Operating Limits		
	Thermal	Voltage (out of bounds)	Voltage instability	Dynamic instability	Don't know where you are operating
Mitigation time, Tm.	Tm ≤ Equipment rating		Tm = As soon as possible		
Precontingency load shedding	May be required, though not likely because other actions are usually fast enough.		May be required if other actions do not mitigate the exceeded limit fast enough to prevent the uncontrolled loss of Interconnection integrity[13]. Instability can propagate through the Interconnection very quickly.		
	At some level, these can become IROLs				
Note: Tm is the time limit for returning the system to within a system operating limit or interconnection reliability operating limit. It is not a compliance violation measure.					

[13] NERC defines cascading as "The uncontrolled loss of bulk electric system facilities triggered by an incident (or condition) at any location resulting in the interruption of electric service that cannot be restrained from spreading beyond a pre-determined area."

Salient features of System Operating Limits and Interconnection Reliability Operating Limits

We will now list the salient features of these limits, the consequences when they are violated, how long the system operator has to mitigate those violations, and whether *precontingency* load shedding is more or less likely (see text box on following page, “The Role of Precontingency Load Shedding”). And note: when we use the expression “operating limit violation” in this document, we are using “violation” in the technical sense—as in “overload”—not as a compliance violation of a NERC standard. To make this point clearer, we will refer to the violation mitigation time as Tm rather than the conventional Tv.

1. All of these operating limits are *system* operating limits because, even though many are a function of equipment or element ratings, they are determined as part of the interconnected system.
2. Thermal SOLs are local, typically confined to one or maybe a few elements, like a transformer, breaker, line, or generator. Generation and transmission equipment are typically rated as a function of both time and load level. They have a “normal” or “long-term” rating, and one or more defined time-limit ratings, such as a 2-hour rating which may be based on 120% of the normal or long-term rating, or 15-minute rating which may be based on 200% of the normal or long-term rating. Therefore, the mitigation time, Tm, is a function of the equipment rating. It would be perfectly acceptable for a transformer to be loaded to its 2-hour rating for 2 hours, or its 15-minute rating for 15 minutes, but not longer. In this case, the SOL violation of the normal or long-term rating begins the moment the equipment continues to be loaded beyond its Tm.
3. This means the system operator must have a plan that ensure equipment will not operate longer than its time-limit rating.

The role of precontingency load shedding. Manual load shedding is an operating strategy that can mitigate an SOL or IROL violation very quickly. When the system operator knows the transmission system is violating an IROL, he quickly determines 1.) how much time he has to return to within the limit (it may be a few minutes, or less), and 2.) his operating options, such as redispatch (including transaction curtailments) or transmission reconfiguration or load shedding. The quickest of these may be manual load shedding, and the system operator will chose that option if, in his judgment, the risk of cascading failure or severe equipment damage (unacceptable performance) resulting from the next credible contingency is too great. Remember, IROL violations do not require a “triggering” event (contingency), and the system operator has to manage risk. So the choice to shed load “pre-contingency” is very prudent if the Interconnection is at risk for the next credible contingency and the system operator decides that redispatch or reconfiguration will take too long.

That said, how fast is “As Soon As Possible?” We have historically written in our standards that the system operator must mitigate in IROL “as soon as possible.” And then we try to define what that means. How soon is soon enough? How do we judge what is “possible?”

The simple fact is that there is no single term or expression that conveys both “do it right now” and “but don’t do anything rash.” Regardless of what we say here, it will ultimately be up to the experience and judgment of the system operator to weigh his options and manage his risk so the consequences are acceptable.

4. Voltage SOLs are relatively “local.” They might cause some customers to lose service, or damage customer or transmission or generating equipment, but they don’t radiate very far to other parts of the Interconnection. The system operator needs to mitigate these

SOL violations **according to the equipment rating** at that particular voltage level.

5. Interconnection Reliability Operating Limits are a function of instability, which is what distinguishes them from thermal or static voltage System Operating Limits. And that's an important distinction. There two varieties of instability: 1.) "steady-state," like a metronome or other object vibrating at its natural frequency, and 2.) "dynamic," like unsuccessfully balancing a broomstick on the palm of your hand. In either case, they are bad, and in the latter case, even worse.

6. Voltage instability occurs when the interdependency between voltage and reactive supply breaks down, while dynamic (or phase angle) instability occurs when the electro-mechanical "lock" of the generators connected to the Interconnection is lost.[14]

7. **Because instability can propagate through the Interconnection so quickly (from minutes to fractions of a second), the system operator must mitigate IROL violations very quickly: "as soon as possible." There is simply no specific time limit.**

8. **The system operator is also violating an IROL if he is operating outside the boundary conditions that were established in the operations planning timeframe.** Quite simply, the act of not knowing where you are, which means not knowing the results of the next credible contingency, means the system operator has no way of managing that risk. Therefore, the system operator must have a plan to return to the boundary conditions established in the operations planning timeframe, or to define new boundary conditions that the operator knows will be safe.

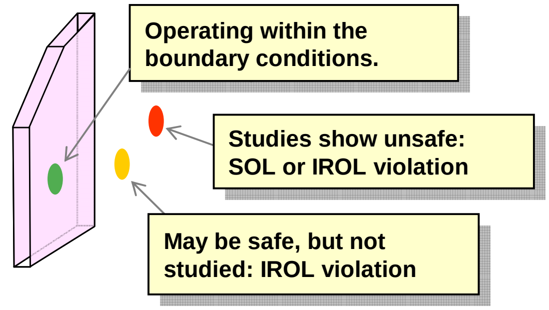
9. The system operator may mitigate any system limit violation as though it was an Interconnection Reliability Operating Limit violation.

Operating limit violations and contingencies

We hope it's clear that we don't need a contingency to cause a System Operating Limit or Interconnection Reliability Operating Limit violation. Violations of SOLs and IROLs are actually violations of the boundary conditions, which means the system operator is in a place that either 1.) operating planning studies reveal that credible contingencies will not produce acceptable performance, or 2.) that wasn't studied. It's just as possible for the transmission system to "wander" outside its boundary conditions as it is to be yanked by a contingency. If the system demand grows well beyond the forecast, or parallel flows increase from transactions elsewhere on the

[14] These are very simplistic explanations.

Interconnection, or the generation dispatch isn't properly considering congestion, the system operator may find he is outside the boundary conditions even though no single event landed him there. And he will know this because he is exceeding his system operating limits.



Suppose the new place he lands is actually perfectly safe. If a credible contingency were to happen, the transmission system would still respond as predicted. Is that OK?

The answer is no, it's not OK—it was simply fortunate. Remember that the boundary conditions, and ultimately the system operating limits, were derived from operating studies. We used our best load forecast based on our best econometric model, our best knowledge of the generators that would be available, our latest generator and transmission expansion plans, against a set of credible contingencies. We awarded a "green dot" to the tests that resulted in our acceptable performance and a "red dot" to those what didn't. And we interpolated—not extrapolated—between those green-dot studies to define the boundary conditions that looked like an enclosed box. Inside that box are the places that we know the system will respond acceptably following a credible contingency.

But because we cannot study every possible situation, we don't know for sure where *every* green dot *might* be. If we had studied more extreme load forecasts or higher interchange levels, we might have found more green dots and could expand the box. But we didn't do those studies and cannot assume green dots exist anywhere else.

Real-time Operations Time Frame

Next hour

By the "next hour" we mean the next 15 minutes, or 30 minutes, or 60 minutes during which the system engineers, operators, and reliability coordinators will 1.) run their state estimators and perform contingency analyses or plot where they are operating on pre-calculated system operating limit nomographs, and 2.) prepare to take some kind of action to operate within system operating limits. These actions are usually limited to generation regulation (AGC), redispatch (MW and MVAR), moving transformer taps, switching reactors in or out, adjusting interchange schedules, and regulating customer demand to the point of firm load shedding.

Credible contingencies in Real-Time

Before ending this section, we need to explain an important point: Transmission line and generator outages that have already happened are *no longer contingencies* in real-time. Contingencies, by definition, are events that haven't happened; in real-time, the transmission system is what it is. If six lines tripped out 43 minutes ago, then the lines aren't in service now, and the system operator must still prepare for the *next* credible contingency. If the system operator hasn't studied this new configuration or knows where he needs to posture the system, then he doesn't know where he is operating, and needs to figure this out very quickly.

Outages that recently happened are no longer contingencies that are about to happen, and the system operator must be prepared for the next credible contingency.

Summary

1. The boundary conditions established in the planning and operations planning timeframes become the system operating limits as the next-day and next-hour operating conditions become more defined.
2. Operating within the system operating limits should result in the expected performance of the Interconnection.
3. The points that were tested in the next-day and next-hour studies define the scope of coverage in real-time.
    a. Those studies may, or may not, have included adjacent transmission systems, or other more remote parts of the Interconnection. Therefore, boundary conditions are only as accurate as the depth and breadth of those studies.
    b. The system operator and reliability coordinator must clearly understand what the boundary conditions include and how they are calculated.
    c. Studies that don't converge or result in the Interconnection not performing as expected define operating states that are outside the boundary conditions.
    d. Operating outside the studied boundary conditions is an operating limit violation.
4. Events that happened in the past are not contingencies in real-time, because contingencies, by definition, haven't occurred.

Restoration

We are not going to delve into restoration in this document, other than to state quite directly that our planning and operating criteria must provide for it. If the system operator is in this process, it's because he was unable—for whatever reason—to successfully manage the risks that drove the system beyond the boundary conditions. We hope the concepts in this document will help NERC develop the operating and planning criteria and standards that result in credible contingencies result in acceptable performance.

Bibliography

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